**Michael D. Cannata, Jr. | Senior Consultant, Accion Group, Inc.**
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**As the former Chief Engineer of the New Hampshire Public Utilities Commission** and a former managing engineer with the Public Service Company of New Hampshire in transmission and generation planning, energy management, and system operations, Mr. Cannata supports Accion's team with his expert knowledge of power system studies and planning and interconnection analysis. Before joining Accion Group, Mr. Cannata served as a technical advisor to the Maine Public Utilities Commission, the Vermont Public Service Board, the Kentucky Public Service Commission, and the District of Columbia Public Service Commission regarding the public necessity and convenience for a multitude of 345 kV, 230 kV, 161 kV, 138 kV, 115 kV, and 69 kV facilities. Additionally, Mr. Cannata has conducted management audits of major utility organizations, executed prudence reviews of major fossil and nuclear plant outages, and served as the prime architect for one state's heavily litigated electric utility restructuring settlement.

## Experience

Chief Engineer, New Hampshire Public Utilities Commission
Director, Power Pool Operations, Public Service Company of New Hampshire
Manager, Computer Department and System Planning, Public Service Company of New Hampshire
Senior Consultant, The Liberty Consulting Group
Management audits of major utility organizations
Investigations of major system outages
State siting decision maker
State Office of Emergency management decision maker
Prudence reviews of major fossil and nuclear plant outages
Utility merger analyses
Prime architect for one state's heavily litigated electric utility restructuring settlement
Principal technical and analytical member of the Seabrook Nuclear Plant sale
Technical advisor for international DC interconnection facilities
Core participant in the resolution of a major utility bankruptcy

## Major Clients

Alabama Power Company
Arizona Public Service Commission
Confidential Investment Bankers
D.C. Public Service Commission
Georgia Power Company
Illinois Commerce Commission
Kentucky Public Service Commission
Maine Public Utilities Commission
Maryland Public Service Commission
New York Public Service Commission
NH Public Utilities Commission
Nova Scotia Utility and Review Board
Office of the MA Attorney General
Ohio Public Utilities Commission
Reliant Energy Corporation
Vermont Public Service Board

## Industry Specialization

Analysis of Utility Reliability, Safety, and Operating Practices
Economic Evaluations
Expert Testimony
Generation Planning
Generation Plant Siting
Mergers and Acquisitions
Non-Utility System Interconnections
Power System Operations
Risk Management
System Reliability Analyses
Transmission and Gas Line Siting
Transmission Planning
Utility Acquisitions
Vegetation Management

## Education

MBA, Northeastern University
MSEE Power Systems, Northeastern University
BSEE Power Systems, Northeastern University
Professional Engineer – New Hampshire #5618

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## Relevant Experience

### Audit and Operations Review

Lead Consultant for Liberty Consulting Group's review of the transmission system of Nova Scotia Power for The Nova Scotia Utility and Review Board. Liberty's review examined (1) system maintenance, inspection, structural design, materials, staffing, and related matters, (2) system planning, operations, system design, lessons learned, and other matters, and (3) utility communications, call center operations, staffing, outage management system, lessons learned, and related matters after the collapse of multiple transmission lines in November 2004.

Lead Investigator in the review of the response of Massachusetts Electric Company to the major snowstorm that occurred in October 2011 for the Office of the Massachusetts General.

Currently assisting the Staff of the New Hampshire Public Utilities Commission in its review of the response of four major electric companies to major storms occurring in 2011.

Lead investigator into the reliability of the Potomac Electric Power Company distribution system and the quality of service it provides to its customers for the Maryland Public Service Commission.

Lead Investigator in the management audit of Consolidated Edison Company of New York reviewing adequacy of multi-area transmission planning and resource adequacy within the multi-area system for the New York Public Service Commission, including review of the electric and gas system designs.

Lead Investigator monitoring Commonwealth Edison's implementation of T&D system reliability improvement recommendations resulting from major system outages for the Illinois Commerce Commission.

Lead Investigator in the prolonged outage of Ameren T&D facilities following severe wind and ice events in 2006 for the Illinois Commerce Commission.

Lead Investigator monitoring Ameren's implementation of T&D system reliability improvement recommendations resulting from major system outages for the Illinois Commerce Commission.

Lead Investigator in the investigation of transmission grid security in Illinois after the August 2003 blackout for the governor's blue ribbon committee.

Lead Investigator reviewing the operation and outage of the fossil power plants of Arizona Public Service Company for the Arizona Public Service Commission.

Lead Investigator reviewing the operation and outage of the fossil power plants of Duke Energy – Ohio for the Ohio Public Utilities commission.

Lead Investigator in the in-depth root cause analysis of a fire at a major Commonwealth Edison substation for the Illinois Commerce Commission.

Lead Investigator of the reliability of the T&D systems of four electric utilities in Maine.

Lead Investigator in the review of distribution and transmission practices at Alabama Power and Georgia Power Company.

Served as the principal technical member of the Seabrook nuclear unit sale team acting for the New Hampshire Public Utilities Commission.

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## Relevant Experience (continued)

Lead Investigator in prudence reviews of major fossil and nuclear plant outages for the New Hampshire Public Utilities Commission.

Investigated the causes of overlapping unit outages at a major Reliant generation facility.

### Dispute Resolution

Prime architect of the settlement between the State of New Hampshire and Public Service Company of New Hampshire (PSNH) that ended years of litigation and allowed statewide competition in the electric industry to proceed.

Re-drafted the State of New Hampshire Bulk Power Siting Statute and facilitated resolution of widespread legislative tensions.

### Renewable Energy Projects

Lead Investigator reviewing the adequacy of system interconnection requirements of a major renewable fuel resource for the Nova Scotia Utility and Review Board.

### Restructuring

Advisor for the New Hampshire Public Utilities Commission in the merger of National Grid and Key Span and the sale of Verizon assets to Fair Point Communications.

Principal technical and analytical member in the Seabrook Nuclear Unit sale team acting for the New Hampshire Public Utilities Commission.

Core participant in the merger/acquisition team activities culminating in the corporate reorganization of PSNH. Recognized and developed a successful employee retention program used during the acquisition.

### Strategic Energy Planning

Evaluated the appropriateness of the proposed Storm Fund Adjustment Factor and the Inspection and Maintenance Program Basis Service Adjustment Mechanism for Power Option, a load aggregator in Massachusetts Electric Company's first delivery rate case in 10 years.

Technical advisor to the Maine Public Utilities Commission, Vermont Public Service Board, Kentucky Public Service Commission, and the District of Columbia Public Service Commission regarding the public necessity and convenience for a multitude of 345 kV, 230 kV, 161 kV, 138 kV, 115 kV, and 69 kV facilities. Included in these many engagements were the Maine Power Reliability Project consisting of over 350 miles of 115 kV and 345 kV facilities.

Advisor to the Commission on utility system and operational issues including those of alternative energy generation.

### Transmission and Distribution

Responsible for the operation and dispatch of PSNH transmission and generation facilities through the New Hampshire Electric System Control Center.

Developed real time integrated transmission system loading capabilities for the New Hampshire Electric System Control Center.

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## Relevant Experience (continued)

### Utility Planning and Management

Managed a professional staff of engineers and analysts engaged in investigations regarding safety, reliability, emergency planning, and the implementation of public policy in the electric, gas, telecommunications and water industries.

Decision-maker on the Site Evaluation Committee responsible for siting major electric and gas production and transmission facilities.

Sat as decision maker at the New Hampshire Office of Emergency Management's Emergency Operations Center.

Instrumental in achieving quality of service levels among the highest in Verizon's service territory.

Core Task Force Member for the DC electrical interconnection between Hydro Quebec and the New England Power Pool.

Director of Power Pool Operations and Planning for Public Service Company of New Hampshire (PSNH)

- Represented PSNH at all major relevant national and regional reliability organizations including:
  - New England Power Pool - System planning Committee; System Operations Committee; Technical planning and operations task forces conducting regional and inter-regional studies and analyses
  - Northeast Power Coordinating Council - Joint Coordinating Council
  - Edison Electric Institute - System Planning Committee

Director of System Planning/Energy Management, PSNH

- Coordinated the company's capital planning requirements for generation and transmission. Integrated its load forecasting and energy management activities
- Lead Participant in the development and implementation of response strategies addressing the negative financial impacts associated with the proliferation of non-utility generation
- Ensured that the interconnections of non-utility generation met utility reliability requirements
- Re-designed the corporate budgeting system to allocate available resources by economic and need prioritization
- Driving force in re-directing corporate economic evaluations towards competitive business techniques

Manager of Computer Department and System Planning, PSNH

- Responsible for the Engineering Division's computer applications support and transmission system planning functions
- Principal in the development, design and implementation of the first-in-the-nation application of 345/34.5 kV distribution
- Resolved daytime corporate-wide computer throughput logjam
- Integrated the Engineering Department's computer applications into the corporate computer organization

## 2011 Capacity/Energy Transactions

### Background

Public Service Company of New Hampshire (PSNH) retains load serving responsibility for customers who have not selected a competitive supplier. PSNH's monthly peak load for 2011 ranged from 773 MW in April, to 1,240 MW during July. On-peak monthly energy ranged from 207 GWh in October to 276 GWh in August, and off-peak monthly energy ranged from 188 GWh in June to 271 GWh in July as highlighted below.

During 2011, PSNH met part of its total system need by purchases from other suppliers including contracts. In 2011, these external supplies ranged from 21% of monthly on-peak energy requirements in February to 78% during September. Off-peak supplies from the market in 2011 ranged from 20% of system need in January and February to 77% in September. For the year, the market supplied a total of 49% of PSNH's on-peak energy requirements and 47% of its off-peak requirements as highlighted below.

**Source of 2011 System Monthly Needs(1)**

| Period | System Peak (MW) | System Monthly Needs (GWh) | | Market Supply (Percentage) | |
|---|---|---|---|---|---|
| | | On-Peak | Off-Peak | On-Peak | Off-Peak |
| January | 1,013 | 261 | 257 | 30 | 20 |
| February | 953 | 239 | 216 | 21 | 20 |
| March | 898 | 252 | 207 | 25 | 31 |
| April | 773 | 209 | 191 | 48 | 45 |
| May | 866 | 210 | 202 | 65 | 68 |
| June | 993 | 251 | 188 | 46 | 33 |
| July | 1,240 | 269 | 271 | 37 | 40 |
| August | 993 | 276 | 216 | 58 | 54 |
| September | 936 | 223 | 205 | 78 | 77 |
| October | 800 | 207 | 196 | 68 | 70 |
| November | 830 | 224 | 202 | 56 | 51 |
| December | 932 | 245 | 243 | 60 | 57 |
| **Total for 2011** | **---** | **2,866 GWh** | **2,595 GWh** | **49%** | **47%** |

1 - Totals may not equal 100% due to rounding.

Accion Group, Inc. ("Accion" or "Accion Group") notes that the market supplied 27% of PSNH's on-peak energy and 18% of off-peak energy for 2010 and those values increased to approximately 49% and 47%, respectively, for 2011. The low gas prices resulted in very low market energy prices offered by the Independent System Operator – New England (ISO-NE) resulting in many times in which PSNH base-load coal units were placed in economic reserve and increasing the percentage of PSNH energy supplied from the market.

**PSNH's Sources of 2011 Energy and Capacity**

In 2011 and at summer ratings,[1] PSNH owned approximately 546 MW of coal-fired generation with four units at two stations, 419 MW of oil-fired generation from two units, 61 MW of hydro-electric generation from nine stations, 43 MW of wood-fired generation from a single unit, and 83 MW of combustion turbine generation from five units at four locations. PSNH also purchased 20 MW of nuclear capability from a single unit, 33 MW from various Public Utilities Regulatory Policy Act (PURPA)-mandated purchases, and 10 MW (no capacity) from an Independent Power Provider (IPP) buyout replacement contract.[2] The PSNH portfolio totals approximately 1,216 MW of summer capability, and 1,268 MW of winter capability. [3, 4]

PSNH must meet its 2011 share of the ISO-NE monthly capacity requirements, which ranged from 1,425 MW in February to 1,478 MW in March. The difference between PSNH resources and the ISO-NE monthly capacity requirement, including reserve requirements, must be met through supplemental capacity purchases. The market supplemental capacity requirement purchases varied from 100 MW during May to 249 MW in June.[5] PSNH also received variable monthly capacity credits from the Hydro Quebec interconnection.

Load obligation requirements were relatively easy to forecast in 2011 due to the persistent low market energy prices. At the beginning of January, approximately 694 MW of PSNH's large customers (33% of PSNH's monthly load) obtained their power supply from the market or self-supplied their energy requirements. By the end of December, the load obligation loss was 771 MW (35 % percent of monthly load). The energy related to customer migration was 232 GWh in January and 242 GWh in December. For the 2011 calendar year, capacity obligation associated with load migration totaled 8,866 MW-months (34% of annual amount) and energy associated with customer migration totaled 2,849 GWh (34% of annual amount). Customer migration hovered between 700 MW and 775 MW on a monthly basis due to the relatively stable and low

[1] In New England, generating units have winter and summer capability ratings. The summer ratings are generally lower to reflect higher ambient and cooling water temperatures.
[2] These figures do not include Lempster Wind or unit contingent contracts.
[3] These figures do not include any capability from the Bethlehem, Tamworth, or the Lempster Wind power purchase agreements.
[4] The units that are owned by PSNH, along with capacity under firm contract are, collectively, referred to as "PSNH Generation" or "own units" in this Exhibit.
[5] In July 2010, the ISO-NE revised its capacity requirements so that only the capacity needed for reliability would be supported.

energy prices in the market. Accion Group notes that in its 2011 Energy Service (ES) filings (including the update), PSNH was using the then-current level of migration occurring at the time of each filing. Those assumptions were reasonable, taking into account the stable and low market prices that existed compared to the PSNH ES rates proposed.

In its ES initial and mid-year forecasts, PSNH modeled that 17,229 MW-months of ES capacity obligation and 5,495 GWh of ES energy would be supplied by ES. In actuality, 17,384 MW-months of ES capacity obligation and 5,435 GWh of ES energy were required. Accion believes that this is a good correlation of forecast versus actual values.

To conduct business in the ISO-NE energy and capacity markets, PSNH uses the resources of its parent company, Northeast Utilities (NU). The table below depicts the number of Full Time Employees (FTEs) charged to PSNH to participate in the New England market.

**Time Sheet Allocation of Wholesale Marketing Department FTEs**

| | 2008 | | 2009[2] | | 2010 | | 2011 | |
|---|---|---|---|---|---|---|---|---|
| **Bidding & Scheduling** | 2.00 | 1.75 | 2.00 | 1.99 | 2.00 | 2.00 | 2.00 | 1.97 |
| **Resource Planning/Analysis** | 4.00 | 2.00 | 4.00 | 1.45 | 4.00 | 2.46 | 4.00 | 2.34 |
| **Energy & Capacity Purchasing** | 2.00 | 0.50 | 2.00 | 0.74 | 2.00 | 0.71 | 2.00 | 0.70 |
| **Standard Offer & Default Service Procurement** | 3.00 | 0.00 | 2.00 | 0.00 | 3.00 | 0.00 | 3.00 | 0.00 |
| **Contract Administration** | 3.00 | 0.00 | 3.00 | 0.00 | 3.00 | 0.00 | 3.00 | 0.00 |
| **Administrative Support** | 1.00 | 0.25 | 1.00 | 0.33 | 1.00 | 0.28 | 1.00 | 0.00 |
| **Renewable Power Contracts** | --- | --- | --- | --- | --- | --- | 1.00 | 0.28 |
| **Management** | 1.00 | 0.25 | 1.00 | 0.11 | 1.00 | 0.13 | 1.00 | 0.09 |
| **Total** | **16.00** | **4.75**[1] | **15.00** | **4.62** | **16.00** | **5.59**[3] | **17.00** | **5.38**[4] |

1 – In 2005 through 2008, PSNH was allocated 4.75 FTEs.
2 – In 2009, FTE allocation by function was by time sheet allocation.
3 – Duplicative manpower was required due to the transition of a new manager.
4 – Additional resources were required to support the Least Cost Integrated Planning (LCIRP) and Newington Continued Unit Operation (CUO) investigations that continued into 2011.

**PSNH's Management of Energy Procurement**

PSNH's energy procurement is managed and coordinated by Northeast Utilities Service Company (NUSCO). During 2011, NUSCO employed the equivalent of 17 FTEs in the Wholesale Marketing Department. Through 2008, an estimated 4.75 FTEs were allocated to PSNH. In 2009, FTEs were allocated to PSNH based on time sheet reporting and 4.62 FTEs were charged to PSNH. In 2010, 5.59 FTEs were charged to PSNH representing an increase of approximately one FTE due to the transitioning of a new department manager.[6] PSNH stated that it expected that the FTE allocation to PSNH to be more representative of historic values (i.e., pre-2010) in the future because the duplicative manpower required during the transition of the new manager in 2010 will not be required. The remaining FTEs were allocated to two other NU subsidiaries who do not have load-serving responsibilities.

In 2011, 5.38 FTEs were charged to PSNH. PSNH attributes the higher than expected charges due to the fact that additional resources were required to support the LCIRP and Newington CUO investigations that continued into 2011. The number of FTEs allocated to New Hampshire does not seem unreasonable given the circumstances given.

From an organizational viewpoint, the New Hampshire position reports to a Connecticut manager. The new manager is spending considerable time in the field at PSNH and, according to PSNH, the field time spent was comparable to historic levels.

**PSNH's Reliance on Supplemental Supplies**

To meet its load responsibility, PSNH requires supplemental on-peak and off-peak (defined by ISO-NE as weekends, holidays, and weekday hours 1-7 and hour 24) energy purchases that change hourly. In 2011, and during on-peak and off-peak periods, purchases varied by period and expected unit operation. PSNH made purchases that were 50 MW block bilateral purchases (described in the following paragraph) that best fit PSNH's supplemental needs. Accion Group considers these requirements to be "fixed," as their requirement is based on the assumed absence of specific contingencies occurring, but does include planned unit maintenance. PSNH stated that the unit capacity value used by PSNH includes a reduction in unit capacity factor reflecting estimated unpredictable forced outages and estimated reserve shutdowns between the planned maintenance periods. The supplemental energy and capacity requirements increase if any part of PSNH's generation portfolio is unavailable when needed to serve load, or if loads are higher than planned due to variations in the weather or customer migration. Likewise, these requirements are reduced when loads are less than planned due to variation in the weather or customer migration. Accion Group considers this portion of the energy supply to be "variable".

In general, PSNH supplemented its generation with monthly, weekly, and daily bilateral purchases to meet the "fixed" portion of its supplemental on-peak requirements and used the

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[6] A new manager was brought into this area in late 2009 due to the then current manager accepting another position within the NU organization.

ISO-NE spot market combined with daily bi-lateral purchases to meet the "variable" portion of its supplemental requirements. The table below shows how PSNH's on-peak and off-peak energy requirements were supplied both historically and in 2011 by its own resources and the bilateral and ISO-NE spot markets. Notably, in 2011 PSNH relied more on market energy due to low ISO-NE energy prices. Load migration was relatively constant throughout the year. Actual weather and major unit outages can also alter the year-to-year percentages.

**Percent Historic and 2011 Supply of PSNH Energy Requirements from PSNH and Market Sources[1]**

| | PSNH Owned Generation (Percent) | | Bilateral and Spot Energy (Percent) | |
|---|---|---|---|---|
| | On-Peak | Off-Peak | On-Peak | Off-Peak |
| **2008** | 56 | 71 | 44 | 29 |
| **2009** | 63 | 73 | 37 | 27 |
| **2010** | 74 | 82 | 27 | 18 |
| **2011** | 63 | 69 | 37 | 31 |

1 - Totals may not equal 100% due to rounding.

The following table shows how PSNH's units supplied PSNH's energy requirements for 2011.

**Percent of PSNH 2011 On-Peak and Off-Peak Energy Requirements Supplied by PSNH[1]**

| Source | On-Peak (Percent) | Off-Peak (Percent) |
|---|---|---|
| **Merrimack** | 34 | 32 |
| **Schiller** | 10 | 9 |
| **Hydro** | 6 | 7 |
| **Vermont Yankee** | 3 | 3 |
| **IPPs** | 8 | 10 |
| **Buyout Contracts** | 1 | 2 |
| **Newington & Wyman (Oil)** | 2 | 1 |
| **Combustion Turbines** | 0 | 0 |
| **Bilateral Purchases** | 23 | 7 |
| **ISO-NE Spot Purchases** | 13 | 24 |
| **Total** | 100 | 99 |

1 - Totals may not equal 100% due to rounding.

The following table depicts PSNH's historical and 2011 market purchases and their source by percent.

**Historical PSNH Supplemental Purchases and Source[1]**

| | Sup. Purchases (GWh) | LT Bilateral (%) | ST Bilateral (%) | ISO-NE Spot (%) |
|---|---|---|---|---|
| **On-Peak** | | | | |
| **2008** | 2,046 | 81 | 7 | 12 |
| **2009** | 1,703 | 90 | 3 | 7 |
| **2010** | 1,011 | 81 | 5 | 14 |
| **2011** | 1,114 | 43 | 23 | 34 |
| | | | | |
| **Off-Peak** | | | | |
| **2008** | 1,210 | 64 | 5 | 31 |
| **2009** | 1,139 | 85 | 2 | 13 |
| **2010** | 564 | 41 | 7 | 52 |
| **2011** | 820 | 8 | 15 | 77 |

1 - Amounts may not total to 100% due to rounding.

### Historic and 2011 PSNH Supply Approach

#### Historic Energy Supply

PSNH has historically altered its approach to supply procurement each year to deal with changing market conditions. In 2010, PSNH altered its procurement strategy from the longer term view used in prior years. PSNH used a much shorter term market focus when making its purchases rather than locking in supplemental supply far in advance. During 2010, PSNH's energy purchases were not from any long-term purchases in advance of delivery except for three 50 MW annual 2010 energy purchases made in 2008 and the Bethlehem and Tamworth unit contingent contracts. Those contracts expired at the end of 2010. Two 50 MW annual 2011 energy purchases also made in 2008 expired at the end of 2011.

#### 2011 Energy Supply

In 2011, PSNH remained heavily focused on short-term transactions due to decreasing market prices throughout the year. In fact, with exception to the two remaining long-term legacy contracts made in 2008 and described above, PSNH made no transactions longer than a month and those transactions were made within a week ahead of projected need.

PSNH conducts biweekly phone calls that include discussion with the generating stations, fuels, operations, and bidding/scheduling personnel. Plant personnel keep capacity/energy planning informed of impending developments at the plants. PSNH used to view Newington as the major unit on its system that interacts with the market. Other former base-load coal units at Merrimack and Schiller have now assumed that role due to the low market energy prices experienced during 2011. All other owned units are either hydro, wood, or long-term resources that are almost always economic or must take contracts[7] or peaking units that are rarely expected to run. PSNH's net monthly on-peak energy requirements were 32 to 100 GWh of bilateral purchases and four to 84 GWh of spot market purchases. PSNH's monthly off-peak net energy requirements were 13 to 71 GWh of bilateral purchases and 12 to 97 GWh of spot market purchases. PSNH determines its incremental energy needs from the market based on the actual weather that occurred, rather than the forecasted average weather in the energy forecast and actual unit operation.

PSNH made purchases based on monthly analyses that involved modeling hourly forecasts by month including a hydro schedule, hourly load forecast, IPP forecast, and its own resources. PSNH modeled its own resources as follows: Combustion turbines and Wyman-4 were excluded because they have extremely low capacity factors and the market price tends to mimic their cost when they do run. Coal units have planned outages specifically modeled and are derated to their annual forced outage rate for the periods in which they run. PSNH's modeling reduces the unit forced outage rate if the unit is projected to be in reserve shut down, but continues to apply historical forced outage rates to remaining generation. PSNH also discretely models the short planned reliability outages for each unit. Newington costs were modeled as the projected market cost of gas or oil corrected for $SO_X$ and $NO_X$ calculations and at a full load dispatch rate. If the cost of Newington was lower than the blocks of power to be purchased, Newington was run as loaded for that block. The remainder of energy requirements was assumed to be supplied by the spot market.

PSNH purchased 733 GWh of on-peak bilateral energy for $50.7 million and 185 GWh of off-peak bilateral energy in 2011 for $8.0 million. In 2011, PSNH also spot-purchased 382 GWh of on-peak energy for $19.4 million and 635 GWh of off-peak energy for $25.8 million. Total energy purchases totaled $103.9 million.

PSNH made spot sales into the ISO-NE spot market both from its own units and resale of unneeded purchased energy. PSNH sold 102 GWh of on-peak energy for $6.7 million and 121 GWh of off-peak energy for $5.8 million. The amount of purchased energy PSNH resold into the market in 2011 was significantly reduced when compared with prior years.

Some purchases are made in advance of expected energy needs. If actual loads are lower than expected, surplus energy may result in the system requiring its sale into the market. The market sold into very often is the spot market or other short term markets. Frequently, when there is surplus energy available, the short-term market prices are low because similar factors such as

[7] Although forecasted to be almost fully economic in 2011 at the time energy rates were set and updated, all PSNH base-load units except Schiller-5 were placed on economic reserve shutdown for many hours in 2011.

cool weather etc. affect all market participants at the same time. Sales into the market often result in unavoidable losses on the transaction.

Total PSNH sales activity of 223 GWh resulted in revenue of $12.5 million. Total PSNH energy purchases cost $103.9 million, resulting in a net cost of energy purchases of $91.4 million.

PSNH determined its 2011 projected unit capacity factors by explicitly modeling planned annual maintenance and through consultation with plant personnel. Short-term planned reliability outages were also discretely modeled and are not included in the overall annualized forced outage factor between outages. The capacity factor tables at the end of this exhibit shows that PSNH base-load units performed near or better than forecasted, except where reserve shutdowns became a factor due to the reduced price of energy in the ISO-NE market. PSNH modeled Merrimack and Schiller units as base load. PSNH personnel reported that their projections produced no reserve shutdowns for these units at the time the 2011 energy service rate was initially set, except for the months of May and October. PSNH personnel also stated that for 2011, load forecasts and supplemental purchase needs were evaluated four times in 2010 prior to the start of the year, and several times during 2011, including the times at which the December 2010 ES rate and June 2011 ES rate update was prepared[8].

**Historic Capacity Supply**

When the Forward Capacity Market (FCM) transition period rules took effect in December 2006, each load serving entity was responsible for meeting its percentage of the total ISO-NE qualified capacity resources. ISO-NE qualified capacity resources were reduced by their individual forced outage rates. The seasonal capabilities of PSNH's units were also discounted for theirs forced outage rates to determine PSNH'S percentage of the ISO-NE supply obligation. The FCM took effect in December 2006 and was in full effect from 2007 through May 2010 using set transition prices. Through May 2010, ISO-NE was in a surplus capacity situation. The FCM transition price of $4.10/kW-month was also clearing price at that time. In June 2010, the FCM floor price was $4.50/kW-month which also became the clearing price. The post-June 2010 $4.50/kW-month clearing price was adjusted downward so that only necessary capacity is supported.

**2011 PSNH Capacity Supply**

Under the FCM rules, PSNH was billed at the capacity rate of $4.50 per kW-month through May 2011, and $3.60 per KW-month from June through December 2011, for its 4.16 to 4.37 monthly percentage share of the 32,702 MW to 34,418 MW of qualified unforced monthly capacity in ISO-NE. This figure equates to 1,425 MW to 1,478 MW per month, less the value of its own resources. The FCM price for 2011 was reduced so that only ISO-NE required capacity was supported on a pro-rata basis. The ISO-NE capacity rates as adjusted became the clearing price and produced a bill for $62.1 million for capacity and PSNH unit capacity produced a $52.1 million credit, leaving PSNH with a net $10.0 million capacity cost for 2011 which was a

[8] During a 2010 technical conference, PSNH indicated that it is now updating its load forecast on a quarterly basis.

reduction of $2.2 million from 2010 capacity costs and a $19.9 million reduction from 2009 capacity costs.

**PSNH Generation Units' Interrelationship with the 2011 Energy Market**

Where much of PSNH's generating units have historically been considered either base-load generation (and generally lower priced) or peaking generation (and more expensively priced than the market, respectively), it was not expected that their operation would be significantly influenced by market prices. This relationship changed in 2011. Prices in the ISO-NE market fell to levels not previously experienced. PSNH base-load units at Merrimack and Schiller Stations except for Schiller-5 were at many times placed into economic reserve status.

The price of energy purchased from the ISO-NE market decreased in 2011 as additional gas supplies entered the northeast energy market. The lower energy prices in 2011 resulted in PSNH's previously base-load coal units (Merrimack-1, Merrimack-2, Schiller-4, and Schiller-6) being placed on economic reserve for many more hours than in previous years and many more hours than PSNH had forecasted. PSNH had to change operations and maintenance practices at its coal units much like it previously did for Newington to maximize operations and minimize costs in a changing marketplace.

In 2011, energy service loads generally were as forecasted by PSNH and PSNH continued to rely on the market for a significant portion of its energy requirements (including during times of system planned maintenance outages) even though approximately 35 percent of the monthly energy requirements of large customers were met from the market or self-supply, resulting in reduced supplemental purchase requirements.  Market prices were low throughout the year. With low market energy prices in 2011, PSNH continued to be very susceptible to both low market price in relation to the cost of its formerly base-load units, and to fluctuations in the supplemental purchase volume, which was due to changing economic conditions and to a lesser degree from customers migrating to and from competitive supply options. As market prices edged lower, however, customer migration appeared steady indicating that those customers who could migrate had already done so and that few, if any, customers returned to PSNH for energy service.

**Financial Transmission Rights**

PSNH uses Financial Transmission Rights (FTRs) in all hours where it expects its units to run to protect against congestion pricing in the market.  In essence, FTRs trade a potentially high and variable congestion price for a known price. FTRs are limited by actual system capability, function much like a hedge, and bring certainty to the price of generation with regard to congestion.  FTRs are purchased as needed between the major PSNH generation sources (Vermont Yankee, Merrimack, Newington, Schiller, and the Mass. Hub and collectively known as the source locations) for the months they are expected to run or in which purchases are made from the market and the New Hampshire load zone (referred to as the sink location). In 2011, PSNH significantly reduced FTR purchases such that a total of 1,605 GWh of on-peak and off-peak FTRs were purchased. PSNH factored in known outages and expected load into its decision process. Few FTR purchases were made for Newington in 2011 and those that were purchased were for off-peak conditions in a few months. The table below shows PSNH's historical and 2011 FTR purchases, their value regarding avoided congestion costs, and their cost to PSNH customers.

**PSNH Historical and 2011 FTR Costs and Savings**

| Year | Auction Cost (Thousands) | Avoided Congestion Costs (Thousands) | Net Cost (Benefit) (Thousands) |
|---|---|---|---|
| 2008 | 827 | 237 | 590 |
| 2009 | 10 | 122 | (112) |
| 2010 | 31 | 400 | (369) |
| 2011 | 16 | (7) | 23 |

With the 2011 reduction in market energy prices, PSNH appropriately reduced dependence on FTRs as lower market prices reduce the dependency of movement of energy on the ownership of FTRs.

**Historical and Actual Unit Performance**

The historical performance of PSNH units is considered when determining when to procure supply from supplemental sources. Heat rates are also a useful tool in tracking how efficiently a unit converts fuel to electrical energy. The table below depicts the historical average heat rates and average heat rates for 2011 for PSNH's major units and the units' current full load heat rates.

**PSNH Major Unit Historical, 2011, and Full Load Unit Heat Rates**

| Unit | Average Annual Heat Rate (BTU/kWh) | | | | Full Load Heat Rate (BTU/kWh) |
|---|---|---|---|---|---|
| | **2008** | **2009** | **2010** | **2011** | **2011** |
| **Merrimack-1** | 9,933 | 10,211 | 10,221 | 10,435 | 9,900 |
| **Merrimack-2** | 9,723 | 9,919 | 9,663 | 9,826 | 9,520 |
| **Newington** | 11,690 | 12,382 | 13,517 | 13,429 | 10,900 |
| **Schiller-4** | 12,244 | 13,019 | 13,073 | 14,545 | 12,900 |
| **Schiller-5** | 16,689 | 17,122 | 17,131 | 15,401 | 15,800 |
| **Schiller-6** | 12,072 | 12,644 | 12,588 | 14,195 | 12,300 |

The above table shows stability in the efficiency of Newington, declines in efficiency of the coal units at Merrimack and Schiller due to being placed on economic reserve shutdown more often, and an increase in efficiency at Schiller-5 due to maturity and experience in operation of the unit. The ISO-NE more frequently starts, stops, or runs the PSNH four coal units at reduced load. This mode of operation negatively impacts unit efficiency. The actual heat rates are consistent with a reduced mode of operation as dictated by the market.

**Historic and 2011 Unit Capacity Factors**

The table below shows the historical capacity factors and the projected capacity factors used for the 2010/2011 period.[9]

**Historic Actual, 2011, and Projected Annual Capacity Factors for PSNH Major Units in Percent (Annual Generation/Winter Rating/8760)**

| Unit | Actual Capacity Factor(2) | | | | Projected Capacity Factor (CF) |
|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2011 |
| **Merrimack-1** | 79.8 | 84.1 (1) | 67.2 | 57.9 | 65.2 |
| **Merrimack-2** | 72.8 | 56.1 | 67.5 | 47.9 | 70.8 |
| **Schiller-4** | 78.5 | 59.5 | 53.4 | 28.8 | 52.7 |
| **Schiller-5** | 79.8 | 79.6 | 79.0 | 78.3 | 75.7 |
| **Schiller-6** | 80.7 | 56.9 | 51.0 | 25.3 | 53.6 |
| **Newington** | 3.3 | 5.2 | 6.4 | 3.6 | 2.4 |

1 - No unit overhaul in this year.
2 – Actuals reflect reserve shut down periods.

One can demonstrate how coal unit capacity factor reductions are solely due to the placement of the unit on economic reserve and not poor maintenance practices. Add the actual 2011 coal unit capacity factor (above table) and the actual 2011 reduction of coal unit capacity factor (table below) together and subtract the PSNH projected coal unit capacity factor results in a value that is close to the historic base-load capacity factor of the unit (actual 2008 capacity factor in table above). Any other difference at Merrimack Station can be attributed to the lengthy outages related to the Clean Air Project tie-in.

In the following table Accion presents the impact of economic reserve shutdowns on normal capacity factors for the major units.

[9] Calendar 2011 is in this period.0

**Reduction of Unit Capacity Factor Due to Economic Reserve Shutdowns (Percent)**

| Unit | Actual Reduction in Capacity Factor | | Projected Reduction in Capacity Factor |
|---|---|---|---|
| | 2010 | 2011 | 2011 |
| **Merrimack-1** | 9.4 | 10.9 | 4.3 |
| **Merrimack-2** | 9.6 | 26.6 | 0.0 |
| **Schiller-4** | 10.8 | 46.2 | 12.5 |
| **Schiller-5** | 0.1 | 0.0 | 0.0 |
| **Schiller-6** | 20.2 | 53.4 | 17.0 |
| **Newington** | 78.4 | 85.3 | 92.6 |

**Historical and 2011 Availabilities**

Another important measure of the operation of a unit is the availability[10] of that unit to serve load. For base-load units, the availability is a good proxy to answer the question "Was the unit generating energy economies for customers?" because expected run time is any time the unit is available to run. For non-base-load units, the availability figure degrades in usefulness as the capacity factor of the unit decreases. For example, a combustion turbine may have an availability of 100 percent, but may never operate for appreciable times during the year. Accion Group believes that a more useful measurement of unit and management performance in a market environment is to look at the highest market priced days during the year.[11] The table below depicts unit and fleet historical availabilities during the 30 highest cost market days during the year as traditionally defined.

**PSNH Major Unit Historical Availability on the 30 Highest Priced Energy Days**

| Unit | 30-Day Availability (Percent) | | | |
|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 |
| **MK-1** | 97.6 | 98.4 | 99.2 | 99.3 |
| **MK-2** | 99.8 | 100.0 | 90.7 | 89.8 |
| **NEW-1** | 99.2 | 99.0 | 95.2 | 96.2 |
| **SCH-4** | 99.9 | 92.6 | 97.4 | 99.1 |
| **SCH-5** | 99.4 | 83.8 | 80.5 | 96.2 |
| **SCH-6** | 97.3 | 100.0 | 98.6 | 99.9 |
| **FLEET** | 98.0 | 97.4 | 93.8 | 94.6 |

[10] Normally, availability figures do not show if a unit was at reduced capability while it was available. The industry uses the availability$^{-1}$ metric for that purpose which is the percentage of time the unit would be available at full load.
[11] PSNH included an availability metric which it stated as the "service factor" and defined as the percentage of time the unit was running to serve load at any output level.

**Load Migration**
With regard to migration, Accion Group concluded that it is not difficult to do realistic forward looking market purchases when approximately 35% of the load to be served can come and go at will with the low market prices that existed in 2011. Remaining PSNH energy service customers see higher costs when other PSNH customers migrate away from the system as the departing customers seek lower power costs. Any excess energy resulting from the outward migration is generally of little value when resold because the market price is low enough to have caused the migration. Likewise, customers remaining on the system also see higher costs when migration into the system occurs. This customer migration occurs when migrating customers seek lower power costs. Any shortage of energy resulting from the inward migration is generally worth more when purchased because the market price is higher, and thus caused the migration. In addition, PSNH's lower cost generation at that time is diluted over a larger MWH load. Because customers have such a flexible menu of choices regarding energy supply, customer migration can vary widely in both directions within the calendar year, making the forecast of supplemental energy needs difficult for PSNH depending on ISO-NE market prices. In 2011, energy prices were relatively stable and low throughout the year, resulting in stable customer migration in the amount of approximately 35% of total customer load. In 2011, customer choice of supplier was not a significant influence on PSNH's market purchases.

**Evaluation**
Accion Group reviewed the capacity/energy planning testimony filed by PSNH, conducted an on-site interview with knowledgeable personnel responsible for the capacity/energy planning function at PSNH, submitted follow-up data requests, and reviewed detailed backup information of the summary results supplied by PSNH.

Accion Group concluded that the PSNH filing is an accurate representation of the process that took place in 2011. Accion Group believes that PSNH made sound management decisions with regard to capacity and energy purchases and sales in its market environment, and that PSNH's actions were consistent with its least cost plan as modified on March 28, 2008. Accion Group also concluded that the capacity factor projections used by PSNH in its purchase projections were reasonable at the time they were made.

**Merrimack Outages For 2011**

This exhibit covers the review of the specific outages that occurred at both Merrimack-1 and Merrimack 2 including the tie-in outage(s) for the Clean Air Project (CAP). The process of selecting the CAP tie-in outage approach, the reasoning behind why items were done at the time they were done, and the related prudency review, has been separated and is contained in a special exhibit entitled "Exhibit – MDC-3A".

The major projects at Merrimack Station this year were the maintenance overhauls of both units and the tie-in of the CAP. Merrimack Station is also approaching five years without a lost time accident.

**Merrimack-1**

The following outages occurred at Merrimack-1 during 2011. This unit is on a two-year overhaul schedule and had a scheduled overhaul performed in 2010. The major projects for this unit in 2011 were the water wash/vacuuming of the boiler, repairs to the cyclone burners, refractory cure and chemical cleaning of the boiler, and the CAP tie-in.

A - (Outage Report OR-2011-01)
1/4/11 – 2.8 days
The unit was taken off line due to excessive water use due to a furnace wall tube leak. PSNH also found that damage occurred to an adjacent tube. Repairs were made to both tubes and the unit returned to service.

B
1/24/11 – 0.1 days
The unit tripped from a no load steam flow trip activation. The unit is designed such that turbine steam is measured from the difference in pressure across a pressure sensing line at the first stage of the turbine to a pressure sensing line at the cold reheat section of the turbine to indicate that steam is flowing through the turbine. In this event, the cold reheat pressure sensing line froze which gave a zero pressure drop indication that tripped the unit. The Merrimack-1 turbine is located outdoors in an unheated but covered turbine deck with Unit 2. The Unit 1 and Unit 2 turbines provide the main source of heat to the area and both units were in operation at the time of the event. The temperature at the time of the trip was minus 9$^{o}$F with a wind chill of minus 28$^{o}$F. PSNH installed a temperature alarm in this area so that temperature can be monitored during cold snaps.

C

4/12/11 – 32.7days

This maintenance overhaul outage was scheduled for 38.1 days. PSNH obtained an ISO-NE outage window of 40.8 days for the outage. The unit returned to service approximately 5.4 days earlier than the scheduled completion date. The outage critical path throughout the outage was the cyclone and refractory work followed by chemical cleaning of the boiler. Cyclone and refractory work was performed with two 12-hour shifts seven days a week. The remainder of plant work was performed with single eight-hour shifts five days a week.

Early completion of water washing of the cyclones and boiler reduced schedule by approximately one day by Outage Day 8. PSNH also found that less stud replacements were required than expected allowing the gain of 1 day by Outage Day 9. The unit remained on the same schedule until Outage Day 25 when application of the cyclone refractory commenced nine hours earlier than expected. An additional 26 hours were gained during the chemical cleaning process by Outage Day 32 as some of the tasks could be performed in parallel. No difficulties or start-up holds were required during start-up gaining 45 hours during that process.

Since the 1990s, Merrimack has been on an approximate 10-year chemical cleaning cycle. In the 2011 chemical cleaning of the unit, approximately one ton of metals were removed from the boiler. This volume is consistent with previous cleanings.

D

5/17/11 – 0.1 days

A delayed start-up occurred when the governor valve actuator lock on the low side oil pressure valve vibrated loose allowing the valve to go out of calibration, which reduced the flow of oil. PSNH increased the speed of the turbine to increase the oil flow and was able to start the unit. After the unit was on-line, PSNH recalibrated the valve but was not able to determine the cause for the locking mechanism to loosen. A PSNH records search determined that the valve was not serviced during the 2011 maintenance overhaul or during recent overhauls.

E

5/29/11 – 0.7 days

A fitting came loose on the no load steam flow sensing line at the high pressure side of the turbine and began to leak. PSNH took the unit off-line to make repairs. Repairs were made and the unit returned to service.

PSNH determined that no work was done on this sensing line during Outage B above (same system) or during the maintenance overhaul. PSNH was unable to determine why the fitting loosened.

F
6/10/11 – 0.8 days
The unit was taken out of service due to a high vibration in the upper guide bearing of the 1A condensate pump. Repairs were made and the unit returned to service.

G
6/14/11 – 0.3 days
During Outage F above, PSNH noticed a drip coming from the floor of the boiler and had been trying to locate the source of the leak since that time. A small weeper leak was found and this outage was taken to determine the extent of the repairs required and to make ready for those repairs. Also see Outage H directly below.

H
6/16/11 – 0.8 days
PSNH took the unit off-line to repair the leak in the floor section of the boiler. Repairs were made and the unit returned to service.

I
7/13/11 – 1.7 days
During a previous start-up, PSNH identified that the right side turbine throttle valve did not open all the way. Investigation found that the guide pin that guides the linkage for the throttle valve was slightly bent. At this time, the unit was in economic reserve so PSNH took the outage to repair the valve linkage guide pin.

J
9/6/11 – 19.0 days
This outage was taken to tie Unit 1 into the CAP and was scheduled for 21.1 days. PSNH obtained an ISO-NE outage window of 21.6 days for the outage. The unit returned to service approximately 2.1 days earlier than the scheduled completion date. The outage critical path throughout the outage was the CAP tie-in to the supplemental precipitator outlet duct. Disassembly, assembly, and commissioning activities were worked with two 12-hour shifts for seven days a week. Critical path work was reformed with one 12-hour shift for seven days a week and reduced to one ten-hour shift for seven days a week as the outage progressed.

Prior to the outage, PSNH and URS (United Research Services), the Program Manager, who provides oversight of all projects/contracts, integrated the PSNH tie-in schedule with a conservative URS tie-in schedule. PSNH stated that its schedule was well ahead of the URS schedule. As noted below, all URS schedule gains were within the PSNH schedule capabilities.

The outage schedule gained 20 hours on Outage Day 3 when ash removal at the supplemental precipitator took less time than planned. Less than expected amounts of ash were found allowing the gain in schedule. The supplemental precipitator duct at the tie-in location was being removed in six sections. By Outage Day 7, there was a four-hour loss in schedule as demolition was slower than anticipated. An additional four hours of schedule was lost by Outage Day 10 due to longer preparation of the new supplemental precipitator outlet duct for welding to the supplemental precipitator duct. The outage schedule remained the same until Outage Day 17. By that time, URS had reviewed the start-up testing required for the CAP and was confident that it could be reduced by 24 hours. By Outage Day 18, further URS refinements in the start-up testing logic of which jobs could be done in series, or were required to be performed in parallel, allowed a further schedule gain of 22 hours. During start-up, tuning of the booster fan damper control logic took longer than expected and introduced an eight-hour delay to unit operation.

K
9/30/11 – 0.7 days
A 115 kV/4.16 kV transformer was installed at the station to provide station service to the CAP. Shortly after commercial operation, an operator was taking transformer readings and placed his ladder against the cabinet door to facilitate the visual reading. When the ladder was placed against the cabinet door, the sudden pressure relay activated, tripping the CAP and the unit. A sudden pressure relay is designed to measure a sudden pressure rise in the transformer indicating faulted conditions.

Investigation found that the sudden pressure relay was mounted to the thin metal cabinet door and the placement of the ladder must have jolted the relay, causing its operation. Sudden pressure relays are usually mounted to the transformer itself and are outdoor installations. PSNH relocated the relay to an area in the back of the cabinet where vibration would not be an issue.

L
10/4/11 – 0.2 days
The unit was in economic reserve shutdown and PSNH took this outage to inspect the Flue Gas Desulphurization (FGD) Absorber (mixer) to ensure that it was operating

properly. PSNH opened the doors to the absorber and inspected the mixer, but PSNH found nothing irregular so it returned the unit to service.

M
10/31/11 – 13.5 days
Most units have both forced draft and induced draft fans which push/pull air through the boiler respectively to regulate airflow and boiler pressure. Both Merrimack units have only forced draft fans for this function due to their cyclone design. The original Unit 1 forced draft fans had the capability to force air through the original unit and its initial precipitator, an SCR, and an additional precipitator. In order to incorporate the FGD system into the exhaust path, booster fans were required and were installed as part of the CAP.

After the unit returned to service and operated with the scrubber, unstable unit operations caused by furnace balance pressure upsets occurred. PSNH determined that timing of air changes was difficult and that recirculation (bypass) ducts around the booster fans were required to obtain the desired controllable and variable boiler airflow on October 27, 2011. The unit was operated with real time operator adjustments until this time as PSNH made ready for the required repairs. This outage was taken to install the booster fan recirculating ducts. The unit returned to service and has operated as expected since that time.

**Merrimack-2**

The following outages occurred at Merrimack-2 during 2011. The major projects at this unit in 2011 include the maintenance overhauls of the cyclones, furnace roof support replacements, and the tie-in of the unit to the CAP.

A - (Outage Report OR-2011-02)
1/25/11 – 3.9 days
The unit was taken off-line due to excessive water use that indicates the presence of tube leaks. PSNH found a front wall tube leak in the boiler and a second leak in the F cyclone. When a hydro test was performed on the boiler prior to returning to service, two additional leaks were found in the G cyclone. Repairs were made and the unit returned to service.

B - (Outage Report OR-2011-03)
3/5/11 – 2.7 days
The unit was taken off-line due to excessive vibration in the upper guide bushing of the 2A condensate pump. The bearing was replaced and the unit returned to service.

C
3/8/11 – 0.1 days
The unit was in the early stages of a start-up when it tripped on low steam temperature. Low steam temperature is generally caused by loss of the coal supply, low BTU fuel because of poor fuel quality or incomplete fuel mixing, or a coal "thin out". A coal "thin out" can occur if the coal is wet and a small or partial blockage occurs in the coal feed. PSNH states that no low coal flow alarm was received and that the operator on duty during start-up was experienced. PSNH increased the coal flow to the upper range of acceptable values and started the unit. The exact cause of the outage was not able to be determined, but PSNH was able to rule out wet coal as a potential issue.

D
4/21/11 – 8.0 days
This outage was required to perform high yard transmission work, install a breaker for the feed to MT-3 to the combustion turbines, and to install a 115 kV feed to the CAP. The high yard work required both units to be out of service due to electrical configuration. The outage was scheduled far in advance with ISO-NE and was one of the major reasons the Merrimack-1 annual overhaul was moved to its spring location.

While the unit was down, PSNH performed valve maintenance (including replacement of two valves), coal feeder and forced draft fan maintenance, and replaced or repaired 14 expansion joints. PSNH did as much work as possible so the focus of the fall Unit 2 tie-in outage could be on tie-in issues and not maintenance issues while maintaining resource focus on the concurrent Unit 1 maintenance outage.

E - (Outage Report OR-2011-04)
5/13/11 – 2.2 days
While conducting operator rounds, a steam leak was observed coming from the underside of the turbine. The unit was taken off-line to determine the cause. Investigation found the leak to be coming from the HP/IP turbine governor loop-pipe drain line. A crack in an original weld of the drain line was found and the cause was thought to be low cycle fatigue. The entire drain line was replaced, welds were stress relieved, Non-Destructive Examination (NDE) was performed according to the power piping code, and the unit was returned to service.

F

8/15/11 – 1.9 days

The unit was on economic reserve shutdown and PSNH took this outage to do a boiler inspection. A leak in the 2A cyclone, two in the 2C cyclone, two in the 2F cyclone, and a leak in the flue gas recirculation port were found and the unit was taken out of service for repair. All repairs were made and the unit returned to service.

PSNH had been monitoring pressure because of a small leak. During the outage, additional sealant had been pumped into the generator bearing bracket to stop the leak. Once back in service, PSNH determined that hydrogen loss was still excessive and that further action was required. See Outage G below.

G

8/20/11 – 1.7 days

After returning to service from Outage F, as described above, PSNH determined that the generator bearing bracket had to be removed to fix the hydrogen leak. PSNH enlisted Siemens to perform the work. The bracket was removed, resealed, and the unit returned to service.

H

10/12/11 – 32.9 days

The annual outage was scheduled for 29.6 days. The ISO-NE outage window was for 39.7 days. The unit returned to service in 32.9 days, which was 3.3 days behind schedule. The major work accomplished during this outage included the maintenance overhaul of the seven cyclones, furnace roof support replacements, the installation of new gas recirculation fan inlet dampers, and the tie-in of the CAP. Critical path for the outage initially was the cyclone and refractory work followed by start-up testing of the CAP. Deviations to the critical path schedule are enumerated below.

The boiler floor wash was able to commence 21 hours earlier than expected, resulting in a 21-hour gain in schedule on Outage Day 7. At Outage Day 14, United Dynamics Corp. (UDC) had completed its seven-section inspection of the boiler. UDC recommendations included major repairs to the economizer elbows. Because this work was tied to the leak testing of the boiler, it was in the critical path of the outage. The economizer work resulted in a loss of schedule of 30 hours and placed the economizer work on the critical path.

The A to Z Company (AZCO) performed the work on the booster fan recirculation duct installation project and introduced a 73-hour loss of schedule on Outage Day 16, the day that PSNH made the decision that booster fan bypass ducts were necessary to resolve airflow problems. The loss of schedule took the economizer elbow work off critical path, placed the recirculation duct work on critical path, and provided the economizer elbow work with 52 hours of float.

On Outage Day 24, AZCO made accumulating staffing and logic changes to the booster fan recirculation duct work resulting in a gain of 31 hours to the schedule, but the duct work still remained on critical path. On Outage Day 28, the Unit 1 and Unit 2 start-up schedules were revised requiring that certain tests and start-up procedures were to be conducted in series. This revision to schedule resulted in a loss of 28 hours to the outage schedule and placed the cyclone and refractory work back on critical path. The cyclone and start-up work remained on critical path until the end of the outage.

The original schedule was developed with the thought that the scaffolding placement would accommodate both installation of pin studs on the tubes and application of refractory coating. Such was not the case and the delay of scaffolding removal introduced an 11-hour delay to the commencement of refractory work. An additional 12 hours of schedule was lost due to the introduction of a 12-hour ramp-up delay for unit 1. The original schedule assumed a normal start-up, but additional time was required with the development of an updated start-up plan. Changes to lockout and tagout procedures to ensure safety during the FGD ductwork and damper work added three hours to the critical path. Changes to the booster start-up testing logic and shorter tuning times resulted in a 24–hour gain on Outage Day 34.

I – (Outage Report OR-2011-07)
12/7/11 – 5.5 days
The unit was taken off-line to address independent problems with the gas recirculation fans. These fans are used to recirculate flue gas back to the upper furnace to control stream temperature. Recirculation fan 2A was experiencing high vibration and the outboard fan bearing temperature of recirculation fan 2B was running high. A contractor honed and milled the rotors on both ends of the 2B fans and the bearings of the 2A fan were re-babbited. In addition, both drive couplings were replaced. With the repair work complete, the unit returned to service.

**Evaluation for Merrimack**

Accion Group reviewed the outages above and found them either to be reasonable and not unexpected for these units and their vintage, or necessary for proper operation of the unit. Accion Group concluded that PSNH conducted proper management oversight during these outages.

**Recommendations**

Accion believes that due to the installation of the scrubber at Merrimack Station, new situations exist that can result in common mode failures of both units. Accion recommends that PSNH review the interaction of the scrubber to each unit at Merrimack or the scrubber itself to identify these conditions to determine the necessity of spare parts or additional redundancy to maximize operational efficiency if it does not have plans to do so.

Accion recognizes that each planned outage is unique for one reason or another and that many decisions regarding assumptions must be made when developing an outage schedule. In the case of the Unit 2 tie-in outage, assumptions of conducting start-up of both units in parallel, scaffolding distance and normal start-up procedures required refinement during the outage, resulting in abrupt schedule planning and changes. Accion recommends that PSNH review its planned outage schedules prior to the outage to detect assumptions that need to be verified.

## Merrimack CAP Tie-in Outages For 2011

This exhibit covers the review of the specific outages that occurred at both Merrimack 1 and Merrimack 2 relating to the tie-in for the Clean Air Project (CAP). The process of selecting the CAP tie-in outage approach, the reasons items were done at the time they were done, and their prudency review has been separated and is contained in this exhibit. The specific conduct of the annual maintenance outages, CAP tie-in outages, and other outages required at the station are included in exhibit, "Exhibit – MDC-3".

**The Original Tie-in Schedule**

PSNH's initial 2010 plan to tie-in Unit 1 and Unit 2 to the CAP consisted of taking the Unit 1 maintenance overhaul 35-day outage from 9/6/11 – 10/10/11, directly followed by the maintenance outage of Unit 2 from 10/12/11 through 11/11/11. Other known outages at the station in 2011 were the eight-day transmission yard outage that required both units to be out of service so that planned high yard work and a high side breaker could be installed on MT-3 (combustion turbines step-up transformer).

In late 2010 and early 2011, PSNH recognized the risks associated with the initial outage plan. Some of the major risks identified were:

- Performing never-before-done CAP tie-in work on top of a major maintenance outage for both units at Merrimack Station diverting focus between two major outage objectives.
- Potential of tie-in problems or maintenance outage problems with Unit 1, extending its outage to overlap with that of Unit 2.
- Potential of tie-in or maintenance outage problems extending the outage time of Unit 2 into colder and potential higher priced operating times.

**Revised Tie-in Schedule**

After analyzing the outages at the station that were necessary, PSNH determined that a revised schedule was warranted and that the revised schedule could be implemented for approximately $400,000 (less savings achieved by the changed outage schedule as discussed below) while significantly reducing the risks stated above.

The revised unit outage schedule required Unit 1 to take a separate maintenance outage in the spring (4/12/11 through 5/20/11) and a CAP tie-in outage at the time of its originally scheduled fall maintenance outage (9/6/11 through 9/27/11). Unit 2 outages would remain in place as originally scheduled and consisted of an outage to accomplish the transmission high yard and its combined maintenance and CAP tie-in outage from 10/12/11 through 11/11/11. Additionally, Unit 2 was taken out of service in the spring (4/21/11 through 4/29/11) to complete CAP substation work.

By way of summary, the CAP tie-in proceeded as follows. In September 2011, Unit 1 was disconnected from its stack and was tied directly to the CAP. The stack of Unit 1 will not be used again. In October, Unit 2 was disconnected from its stack and tied directly to the CAP. Additionally, Unit 1 was fitted with bypass duct work such that it could use the old stack of Unit 2 if, for some reason, bypass of the CAP is required. Unit 2 would only be able to operate through the CAP.

PSNH cites the following benefits that it identified in taking a 38-day spring and 21-day fall outage for Unit 1 at a gross cost of $400,000 compared to the original single 35-day fall outage. Each of these benefits have value, however, some cannot be specifically quantified.

- The Unit 1 spring outage allowed outage focus to be solely on maintenance-related issues and the fall outage to focus solely on CAP tie-in related issues.
- Unit 1 would be more reliable for the summer period, having just returned from its maintenance overhaul versus being at the end of its two-year maintenance cycle, if a fall maintenance outage was taken.
- Unit 1 saved having to take a separate eight-day outage in the spring to accommodate the long planned transmission high yard outage.
- The shorter fall outage allowed for approximately two weeks of Unit 1 operation tied to the CAP, providing a window to resolve tie-in issues prior to the tie-in of Unit 2 where no such window existed in the original schedule.

**Impact of Booster Fan Recirculation Bypass Duct Requirement**

As part of the CAP, PSNH installed booster fans to augment the forced draft fans because the original forced-draft fans were operating at their full capability to maintain adequate airflow through the boiler due to the addition of pollution control equipment in past years. PSNH states that the controllability of airflow was recognized at the time of design but that insufficient justification existed to warrant corrective action at that time. When Unit 1 returned to service from its CAP tie-in outage in late September, PSNH noticed immediately that furnace balance pressure upsets were occurring due to the difficulty to control furnace air flow and boiler pressure. To resolve this issue, PSNH placed the airflow controls on manual and had an operator adjust the airflow on a real-time basis. PSNH analyzed various alternatives that could obtain the desired controllable and variable boiler airflow. On October 7, 2011, PSNH decided that the most economical and reliable manner to obtain the desired control of airflow was to install recirculation bypass ducts around the booster fans of both units. Once this decision was made, PSNH expedited fabrication and required that all materials had to be on site by 10/31/11 to coincide with the Unit 1 outage.

Unit 1 was taken off line to have recirculation bypass ducts installed around its booster fan on 10/31/11 for an outage of about 14 days. On 10/28/11, the A to Z Company introduced a revised schedule for the Unit 2 tie-in outage that indicated the installation of recirculation bypass ducts around the booster fan would add approximately three days to the tie-in outage. The outages proceeded close to schedule and both units commenced operation tied into the CAP with virtually no issues.

**Evaluation for Tie-in Outages**

As stated earlier, PSNH conduct during the outages is evaluated in Exhibit MDC-3. Accion reviewed PSNH's actions in planning the upcoming CAP tie-in outages, the relationship of the tie-in outages to other outage requirements at the station, system economics, management approach to risk management, overall management oversight, and overall understanding of the issues. Accion concludes that given the information at the time decisions were required to be made, PSNH exercised good judgment and proper management oversight in the CAP tie-in process for Unit 1 and Unit 2.

## Newington Outages For 2011

### Newington-1

No major capital projects occurred in 2011, as much of the unit's required capital projects were completed in prior years. Newington's overall availability was about 95 percent (98 percent excluding planned maintenance). For 2011, Newington's capacity factor was approximately 3 percent. Historically, Newington's heat rate has been between 11,000 Btu/kWh and 12,000 Btu/kWh. In 2011, the unit heat rate was approximately 13,000 Btu/kWh. Newington's full load heat rate is approximately 10,800 Btu/kWh. The increase in heat rate is due to the manner in which the unit is operated. Unit operation has changed because PSNH now starts the unit on a regular basis in order to ensure that the unit is ready to run if called upon; the unit runs for short periods when called upon for economic operation; and the ISO-NE has calls for operation as spinning reserve more frequently at approximately 100 MW. The additional start-ups and lower operational level translate to a higher heat rate for the unit.

The operation of Newington has changed markedly in recent time. The unit operates many times at reduced loads and at extremely high availability. PSNH believes that these traditional unit metrics are not indicative or reflective of Newington's operation. PSNH has been tracking another metric that it thinks more closely fits the unit's operation. PSNH calls this metric the service factor and is a measure of the time the unit is on-line providing service at any output level. In recent years, from 2009 through 2011, while the Newington capacity factor was 5, 6, and 3 percent respectively, its service factor was 10, 18, and 11 percent respectively.

PSNH gave notice to Nextera in 2010 that its lease of facilities at both Schiller and Newington would be terminated in 2010 in accordance with the lease. The lease terminated and Nextera removed all material from the site. The monies paid by Nextera to PSNH flowed through the ES/SCRC mechanism. Because of the termination of the leases at the end of 2010, no monies are accounted for in the 2011 ES/SCRC review.

Newington Station completed 10 years without a lost-time accident in August 2011 and has had only one lost-time accident in 22 years.

The following outages took place at Newington during 2011:

A
1/14/11 – 0.8 days
While the unit was cold, a leak developed in the furnace corner tubes. This area of the boiler had four similar tube leaks late in 2010. PSNH made the decision to order replacement tubes to be installed during the annual maintenance overhaul. The tube leak was repaired and the unit returned to service. See Outage C, below.

B
3/9/11 – 0.2 days
The unit tripped on high gas pressure during its second all gas start-up. The unit converted to an all gas start-up procedure in 2010 and the unit trip is related to the transfer to the new all gas procedure. When the breaker closed during start-up at 20 MW load, the steam flow requirement increased, thus sending a signal for more fuel. The gas inrush was of such volume that it created a high gas pressure and caused a high gas pressure trip of the unit.

During the conversion to an all gas start-up, PSNH configured the start-up procedure to use two gas guns while rolling the turbine and to pick up load when the breaker was closed. The first all gas start-up picked up load at 17 MW. With what appears to be a sensitivity to pick-up load level, PSNH changed the start-up procedure to, in addition to using two gas guns during the roll of the turbine, the procedure also requires a third gas gun to be in service prior to closing the breaker to pick-up load. In this manner, the inlet gas pressure is reduced when load is picked up. Since this change in procedure was made, no further incidents have occurred during start up.

C
3/26/11 – 15.5 days
This planned outage was the annual maintenance and inspection outage for the unit. The scheduled outage was scheduled for approximately 16.5 days. The major project and critical path for this outage was the coordinated replacement of problematic 345 kV switches and insulators and the replacement of 20 boiler corner tubes. See Outage A, above. PSNH also replaced the 345 kV disconnect on the high side of the generator step-up transformer and two 345 kV lightning arrestors. The remaining lightning arrestor was replaced in 2009 when it failed electrical testing.

Work in the transmission yard continued on a 7-day, 10 hours per day schedule. PSNH performed normal inspections and cleaning during this outage and one abnormality was identified with a lube oil system as described below. PSNH also completed all major priority work existing in its backlog list.

The lube oil system for the turbine and boiler feed pump consists of three oil pumps where two redundant AC pumps are augmented by a DC pump that is used if AC power is lost while the unit is operating.

While performing testing on the pumps, PSNH found that when the 1A pump was simulated as lost, the 1B pump came on and the DC remained in standby mode. This was a correct operation. When the loss of the B pump was simulated, the 1A pump came on but did not build pressure as quickly as it should which initiated operation of the DC pump because of indication that both AC pumps were lost. Investigation found that the discharge flanges of the 1B pump had cracked. No evidence of the crack was given as the flange sits in an oil bath and is not readily visible. Any leak was captured by that oil reservoir.

The lube oil system had this same issue in 2010. GE recommended that the check valves to the pumps be changed. PSNH did so at that time but the issue remained.

The original manufacturer no longer supports, or supplies parts for these pumps. After verification that the pump internals were good, PSNH had two course pump housings manufactured by its maintenance shop in case of a machining error. One housing was machined to final dimensions and the other rough housing was put into stock. A new housing was installed on pump 1A during this outage. During the installation of pump 1A, PSNH noticed that a rack in pump B had developed. The unit was returned to service operating on the A pump with its DC backup. Pump 1B was scheduled to be replaced at a later date. See Outage E below.

D
7/23/11 – 0.1 days
The unit was in operation on Friday and was scheduled to run Friday night and Saturday. On Friday, a high-pressure differential alarm across the boiler feed pump suction line was received. Such an alarm usually indicates that the strainer is plugging. In this case, the unit is operated and the pressure drop is monitored until the pressure drop reaches its limit value. The pressure drop across the suction line increased slightly on Saturday but was within operating limits when the unit tripped on high-pressure drop across the boiler feed pump. PSNH found the boiler feed pump suction line strainer plugged. PSNH checked other strainers and found no buildup in those locations. PSNH attributes the sudden pluggage to a buildup of scale in the system local to the boiler feed pump that

suddenly became separated from the piping walls. The strainer was cleaned and the unit returned to service.

E

9/21/11 – 2.2 days

This planned maintenance outage was taken to perform priority maintenance items prior to the winter season. Included in the outage was the replacement of the turbine/boiler feed pump 1B lube oil pump (See Outage C, above) and the installation of the new condensate pump motor spare for validation. This is the last large motor spare that requires validation. Validation requires that the original motor be removed, the new spare motor installed, and run for a period of time. The original motor is reinstalled at another time and the new spare is put into stock.

F

9/24/11 – 0.1

While in operation on this Saturday, the packing in the main steam valve stub line blew. After consultation with management and with proper steps taken for safety, an attempt was made to seat and reseat the valve without success. This steam stub line acts as a steam equalizing line between the two throttle valve sensors. The steam leak caused the balance between the two throttle valves to become upset, the governor valves began to "hunt", and the unit tripped. The unit was taken off line, the valve repacked, and the unit returned to service.

G

9/25/11 – 0.1 days

The unit was in start-up on this Sunday. When in start-up, the start-up boiler feed pump is used until the unit is loaded to 80 MW where it is swapped over to the main boiler feed pump. When swapped over to the main boiler feed pump, the unit tripped on high drum level. The main boiler feed pump discharges excess water that is not needed to maintain proper drum level through its discharge valve to the recirculation system. Upon investigation, PSNH found a broken coupling between the discharge valve and its actuator. While the indication was that the valve was in the open position because the actuator was in the open position, the valve was actually fully closed. This caused the drum level to rise because all main boiler feed pump water was being fed into the drum, and the unit tripped. PSNH made a temporary weld repair and returned the unit to service. Permanent repairs were made at a later date.

H
10/13/11 – 0.0 days
The unit tripped due to reaching the 10-mil high vibration limit for the turbine during start-up. PSNH rolled the turbine at a slow speed for an hour and then performed a successful start-up. PSNH suspects that unequal leakage at the two throttle valves put an uneven temperature on the turbine during warm-up because of the steam imbalance. The temperature differential in turn causes causing a slight warp in the turbine shaft resulting in the vibration that tripped the unit.

Throttle valve maintenance will not occur until the unit undergoes a major HP/IP turbine overhaul during the next major maintenance cycle. In the meantime until that maintenance can be performed, PSNH has installed an alarm when the turbine rolls off turning gear allowing the operator to take immediate action to prevent turbine shaft distortion. In this manner PSNH can meet ISO-NE start-up time requirements, control added costs, and the address the unpredictable nature of the turbine rolling off turbine gear.

**Evaluation for Newington**

Accion Group reviewed these outages and found them either to be reasonable and not unexpected for this unit and its vintage, or necessary for proper operation of the unit. Accion Group concluded that PSNH conducted proper management oversight during these outages.

**Schiller Unit Outages For 2011**

The major projects at Schiller Station in 2011 were:

The overhaul of Unit 4 that included the five-year inspection of the LP turbine and generator, replacement of the 480 V switchgear to meet new switchgear flashover requirements, and the installation of a new integrator for the multitude of independent control systems.

The overhaul of Unit 5 was its first five-year overhaul since commercial operation of the wood-fired boiler and included complete teardowns of the HP turbine, LP turbine, and generator. Other major projects during the outage included retubing of the air heater and significant refractory work.

The major work of the overhaul of Unit 6 included replacement of the 480 V switchgear to meet new switchgear flashover requirements and general boiler repairs.

Schiller Station had 1 lost-time accident during 2011; an employee slipped while walking up a flight of stairs, which resulted in a hand injury. Prior to this incident, the last lost-time accident was in 2010. Since this incident, Schiller has not had a lost-time accident.

**Schiller-4**

The following outages occurred at Schiller-4 during 2011.

A
5/17/11 – 0.6 days
The unit was in the process of shutting down just after midnight when the main steam stop valve packing developed a leak. The unit was shut down, the valve packing was repaired the next day, and the unit returned to service.

B
6/1/11 – 2.2 days
The unit was taken off-line when it developed a tube leak in the superheater. One leak was found, repaired, and the unit returned to service.

C

6/8/11 – 0.0 days

An operator had reported that the boiler was not acting in its normal fashion. PSNH was in the process of investigating the report when the unit tripped due to low drum level. PSNH continued its investigation and found nothing out of order. The unit was returned to service. See Outage D, below.

D

6/8/11 – 0.1 days

The unit had just returned to service from Outage C, above, when it tripped due to low drum level. PSNH found that the deaerator level indicator was not accurately depicting the drum level. The problem was traced to a bad deaerator controller card. The card was replaced and the unit returned to service.

E

7/6/11 – 0.0 days

The unit had just phased when it tripped a few minutes later. No relay targets were indicated so PSNH re-phased the unit. The unit again tripped without indicating any relay targets. After troubleshooting, PSNH suspected the 67M relay (reverse power relay) was the problem. Reverse power relays are installed to prevent the unit from running backwards as a motor. At Schiller-4, the 67M relay operates in parallel with the 32TT relay which is a similar device and was installed to provide reserve power redundancy from the low steam flow protection system.

The relay was pulled and sent to Eaton for testing. The relay was found to be bad. Eaton procured a used 67M relay, functionally tested it, and found it to be in working order. PSNH installed the used relay on 7/14/11 while the unit was off-line. See Outage F, below.

F

7/18/11 – 0.0 days

The unit was in its first start-up since the used 67M relay was installed in Outage E above when it immediately tripped when phased. No relay targets were annunciated. PSNH pulled the used 67M relay and the unit successfully started. Functional testing of the used 67M relay found it to be good.

On 7/26/11, PSNH set up equipment to record test data on start-up. On 7/27/11, PSNH started the unit without the used 67M relay and the unit started successfully. A repeat test was conducted using the 67M relay from Unit 5 and the unit also started successfully. PSNH made the determination that the used 67M relay was bad. Eaton set up actual field conditions to test the used 67M relay and found that it was bad. When Eaton originally received the relay following Outage E directly above, functional testing was performed as stated above. The functional test ensured that the relay was not damaged in shipping and a mechanical trip check was performed. The field testing conducted as a result of the current outage was what a manufacturer would perform and is much more thorough. During this more extensive testing, Eaton found that the relay trip coil would not drop out when power was flowing away from the generator so that it was always in the trip position. The manufacturer repaired the relay, and PSNH reinstalled it.

G
10/1/11 – 35.4 days
This outage was conducted to perform the five-year maintenance overhaul of the LP turbine and generator, install a Distributed Control System (integrates many independent control systems) and change out 480V switchgear that does not meet new flashover requirements. The outage had an ISO-NE window of 37.3 days. The original PSNH schedule was planned to be 34.1 days. The unit returned to service 1.3 days later than projected. The critical path of the outage involved the complete disassembly and inspection of the LP turbine and generator. This work was to be done on site. Work schedule for the outage consisted of a single ten-hour shift six days a week with overtime worked as necessary to remain on schedule or complete needed backlog maintenance items.

The unit outage stayed on schedule until Outage Day 28. At that time fitting the generator bearing brackets took 12 hours longer than expected. At the end of the outage on Outage Day 34, the air leakage test revealed a small but unacceptable leak in the hydrogen cooler for the generator. The cooler covers were removed and one tube leak was found in cooler #1 and one tube leak was found in cooler #2. Both tubes were plugged and the air leakage test was successful, but an additional 18 hours of schedule was lost.

The unit typically runs at 15 psi of hydrogen to cool the generator. Air leak testing is done at 20 psi.

During the outage, the fourth generator turning gear was inspected and found to be approaching its end-of-life. This is a long lead-time item which PSNH has ordered and will be replaced during the next five-year outage.

H
11/5/11 – 0.0 days
The unit returned from its maintenance overhaul in Outage G, above, and PSNH noticed that the governor was not responding to load as expected. The unit was taken off-line to

make an adjustment to the governor response time. The adjustment was made and the unit returned to service. Governor logic updates were made during the overhaul in Outage G, above.

I
11/9/11 – 1.0 day
Shortly after the unit came on-line, the operator observed a drop in the hydrogen pressure indicating there was an air leak in the hydrogen coolers. PSNH scheduled an outage and tested all hydrogen coolers for leaks. All tested okay. PSNH put extra sealant on the hydrogen cooler covers and returned the unit to service. Air leakage ceased. Accion notes that air leakage tests on 11/5/11 and 11/9/11 were conducted in a cold shutdown condition, which makes finding very small hydrogen leaks very difficult.

As an additional note PSNH air tested the coolers at a later date and they passed the air leak test. Also, in 2012 PSNH increased the air leak test pressure to 25 – 30 psi and found two small tube leaks, not on the sealant surface area. The two tubes were identified and plugged. No leakage problems have occurred since that time. In addition, PSNH has modified its hydrogen cooler testing procedure such that it is done at the higher pressure.

**Schiller-5**

The following outages occurred at Schiller-5 during 2011.

A
2/28/11 – 2.5 days
The unit was shut down due to the request of the Portsmouth Fire Department to put out a fire in the wood yard processing system. The wood processing system has two wood chip paths. Both paths have a mechanism that separates the oversize wood chips, regrinds them, and returns the material to the main chute. The systems are gravity-fed and all have plugged chute detection systems. PSNH investigation found that one of the systems that grinds the oversize chips plugged the chute that feeds the reground chips back to the main feed line. The plugged chute detector failed, and the oversize chip grinder ignited the compressed chips (embers) in that leg of the chip system.

The operator detected smoke and when the operator opened the chute to use a fire extinguisher, the wood chip embers erupted into flames. The operator immediately called 9-1-1. The unit was shut down at the request of the fire department. The fire was contained to the chutes, so no sprinklers were activated. Once the fire was extinguished, power was returned to the wood process system, repairs to belts and pulleys were made, and the unit returned to service.

Since this outage, PSNH has replaced all the plugged chute detectors in the wood yard with a different design that is expected to be more reliable.

B

3/3/11 – 0.0 days

The forced draft fan controller indicated that the forced draft fan motor bearing was at 178°F and tripped the unit while the trip point setting was 203°F. PSNH tested the bearing temperature and found it to be only 80°F. PSNH attributed the difference between the 178°F temperature indication and the 203°F trip setting was due to cool-down time since the trip. Investigation found that the soft-start controller card was bad, indicating an incorrect bearing temperature.

PSNH also recognized that no other fan protection schemes designed by PSNH have trip logic for protection of the bearings and that the trip logic was an Alstom original design. Normal action is to have an alarm function that gives time for the operator to investigate the alarm and take appropriate action. In an effort to prevent similar future trips, PSNH isolated the bearing temperature trip circuit, left the alarm circuit intact, and returned the unit to service. Also see Outage C, below.

C

3/6 /11– 0.3 days

The unit tripped when a high forced draft fan motor stator temperature was indicated. PSNH tested the stator temperature and found that the stator temperature trip was not legitimate. PSNH found a faulty soft start controller card indicating that the trip occurred simultaneously with the alarm. PSNH found that this fan was also protected with the same temperature trip logic found in Outage B above as designed by Alstom. PSNH replaced the soft start controller card, isolated the stator temperature trip circuit, left intact the alarm circuit, and returned the unit to service.

D

4/1/11 – 46.8 days

This outage was the first five-year major maintenance overhaul for the unit since commercial operation of the wood-fired boiler. The outage had an ISO-NE window of 44.4 days. The original PSNH schedule was contemplated to be 43.6 days. The unit returned to service 3.2 days later than scheduled. The critical path of the outage involved the inspection and repair of the HP turbine conducted at Siemen's facilities in Charlotte, North Carolina. The work schedule was as follows: two ten-hour shifts for seven days a week for disassembly and assembly of the HP turbine, 24 hours per day for seven days a week while the turbine was in Charlotte: and, one shift of ten hours for six days a week for HP turbine work at PSNH. All other activities were performed on straight time with overtime worked as necessary to remain on schedule or complete needed backlog maintenance items.

On Outage Day 13, Siemens reported that additional machining in the journal of the rotor bearing and that replacement of the rotor seal strips would be required. Schedules were developed for this work and 72 hours of critical path were lost when the PSNH outage schedule was updated on Outage Day 15. The rotor body seal work progressed slower than anticipated at Siemens and by Outage day 29, an additional 60 hours of schedule was lost. By Outage Day 33, Siemens had gained 24 hours of schedule back on the rotor work. Siemens gained an additional 16 hours of critical path on the rotor work by Outage day 35. By Outage Day 39, Siemens gained a further 22 hours of schedule during the remaining work and was able to ship the HP turbine earlier than projected.

In the early stages of installation of the HP turbine, PSNH made an 11-hour gain in schedule by Outage Day 40. However, on Outage Day 41, 24 hours of schedule were lost when problems developed in the alignment of the HP to LP coupling. An additional six hours of critical path was lost on Outage Day 42, due to the coupling alignment issue, but 11 hours were gained on Outage Day 43 due to easy installation of the HP to LP coupling spacer. In the last days of the outage, a four-hour gain was made on Outage Day 46, a three-hour gain on Outage Day 47, and an eight-hour loss on Outage Day 48.

E
5/21/11 – 0.1 days
The unit tripped due to high forced draft fan vibration. Similar to other events, PSNH found the indication reading to be faulty, isolated the trip circuit, left the alarm circuit intact and returned the unit to service. PSNH found that a previous logic update it made was incompatible with the Emerson controller logic format installed during the overhaul.

F
5/30/11 – 0.1 days
The furnace draft was acting erratically (up and down) and finally tripped on high furnace pressure. Investigation revealed no cause and the unit was returned to service. See Outage H, below.

G
6/20/11 – 0.6 days
The furnace draft was acting erratically (up and down) and finally tripped on high furnace pressure. Investigation revealed no cause and the unit was returned to service. See Outage H, below.

H

6/26/11 – 0.3 days

The furnace draft was acting erratically (up and down) and finally tripped on low furnace pressure. Investigation revealed that the lag time air demand signal was too long and reduced it. PSNH also found that the boiler bias time master (monitors MW demand and boiler steam pressure to determine air and fuel amounts) needed setting changes. The changes were made and PSNH found that similar setting changes were made in May 2010, and were transferred to Emerson for the DCS upgrade during the spring 2011 overhaul.

Emerson investigation found that the logic control updates made by PSNH were not compatible with their update and the system reverted to default settings. Emerson states that because of this incompatibility with the new update logic version, updates to this controller need to be made manually.

PSNH has held discussions with Emerson on this issue and the process for future updates has been changed to reduce the chance of similar occurrences. The new process prescribes a series of steps that need to be sequentially-completed by PSNH and Emerson to ensure that the appropriate information can be transferred.

I

7/23/11 – 0.0 days

The unit tripped due to a high-pressure furnace trip. A wood feed chute had plugged, and when cleared by the operator it created a surge of wood into the boiler, created a pressure transient, and tripped the unit. Where the chutes had already been cleared, the unit was returned to service.

At the time of this outage, there were no plugged chute warnings or alarms in place for the feed chutes. The operator monitors the boiler, and depending on conditions, may be able to determine that a plugged chute condition was occurring, and mitigate the condition before a trip is initiated. Since this outage, PSNH has installed an alarm to indicate when the difference between the freeboard evaporator and the furnace temperature separation reaches 100$^{o}$F, and uses this value as a proxy indication that a wood pluggage event may be occurring.

J - (Outage Report OR-2011-06)

11/12/11– 6.5 days

The unit was taken off line due to the pluggage of three cyclones. The unit was running at 85% to 90% of capability due to increasing pluggage conditions. During the outage the trash screens were inspected and found to have no holes. The water boxes were opened, inspected, and found to have an excess of debris. The water boxes were cleaned and the unit returned to service.

K

11/19/11 – 0.5 days

While coming back on line from Outage J, above, the unit tripped due to a high drum level. Schiller 5 has a small drum and during start-up conditions, small fluctuations in the feed water or steam flow coupled with the addition of bed materials during the start-up can result in a unit trip. Unit 5 is a base load unit and starts infrequently during the year. Also, during this outage and unrelated to the trip, PSNH inspection found that leaves had partially plugged the intake screen and water boxes. The debris was removed from the intake screen and water boxes and the unit returned to service. See Outages L and M below, which occurred during the same start-up.

L

11/20/11 – 0.0 days

The unit tripped during start-up because of a high drum level while trying to stabilize the drum level. See Outage K, above.

M

11/20/11 – 0.1 days

The unit tripped during start-up because of a high drum level while trying to stabilize the drum level.

N

11/25/11 – 0.1 days

The unit tripped due to a high-pressure furnace trip. A wood feed chute had plugged and when cleared by the operator it created a surge of wood into the boiler, created a pressure transient, and tripped the unit. Where the chutes had already been cleared, the unit was returned to service.

O

11/27/11 – 0.6 days

The unit tripped due to a high furnace pressure trip. Based on PSNH's investigation, it thought that one or both of the primary airflow dampers were sticking in the closed position. When the boiler called for more air, the damper opened rapidly, and a surge of air was created that tripped the unit. PSNH could not find a reason at that time for the problem and returned the unit to service. See Outage P, below.

P

12/2/11 – 0.1 days

The unit tripped due to a high furnace pressure trip. PSNH found that the forced draft inlet and dilution primary airflow dampers were not sticking, but fighting each other and over-controlling the combustible air system. To resolve the issue, PSNH put the dilution damper in manual mode and would not allow the damper to be more than 70 % closed. In this mode of operation, the forced draft inlet damper has the capability to pick up the slack.

PSNH looked at the dampers again during the 2012 maintenance overhaul and found nothing out of place. PSNH has left the dampers in manual operation mode.

Q

12/2/11 – 0.1 days

The unit tripped during start-up because of a high drum level while trying to stabilize the drum level. See Outage K, above.

R

12/2/11 – 0.1 days

The unit tripped during start-up because of a low drum level while trying to stabilize the drum level. See Outage K, above.

**Schiller-6**

The following outages took place at Schiller-6 during 2011.

A

3/4/11 – 20.7 days

This outage was the planned maintenance overhaul outage for the unit. The outage had an ISO-NE window of 23.4 days. The original PSNH schedule was set to equal the ISO-NE outage window. Major projects during this outage included replacement of the 480V switchgear and general boiler repairs. The unit returned to service 2.7 days ahead of schedule. The critical path of the outage involved the inspection and repairs related to the boiler. The boiler remained on critical path for the duration of the outage. The work schedule for the outage was one eight or ten-hour shift worked on weekdays, with overtime as necessary to remain on schedule or complete needed backlog maintenance items.

On Outage Day 6, a review of the boiler work progress resulted in a gain of 48 hours to the critical path schedule. The outage remained on schedule until Outage Day 11 when updates to work progress showed that schedule gains were being made. The schedule gains resulted in a 24-hour gain to critical path. By Outage Day 19, minor delays were experienced in performing the hydro test of the boiler resulting in a loss of eight hours to the critical path.

B
3/26/11 – 1.0 days
The unit was in start-up mode after completion of its overhaul in Outage A, above. The unit starts on oil and then switches to coal. When on oil during start-up, primary air is blown through a header that disperses air to the oil nozzles via six pipes. When running on coal, the primary air is forced into the burner with the coal through the pulverizer. In this outage, the coal was coming out of the primary air header while on oil. The actuators for the six louvers that control the direction of primary air were replaced during the overhaul in Outage A, above, and required adjustment. Adjustments were made and the unit returned to service.

C
5/5/11 – 0.0 days
The unit was tripped when an operator was cleaning the emergency electrical panel. The operator hit/bumped the DC breaker for the Burner Management System (BMS) and tripped it. Loss of the BMS then tripped the unit. PSNH states that it was 10 pm in the evening and that the area was dark.

D
5/8/11 – 0.0 days
The unit tripped on low drum level. PSNH's investigation found a bad feedwater controller card. The controller was replaced and the unit returned to service.

E
5/13/11 – 1.1 days
The unit was taken off line due to a tube leak in the superheater. PSNH was able to secure easy access to the leak, make repairs, and return the unit to service.

F
7/5/11 – 0.0 days
The unit tripped on low drum level due to the trip of the 6A coal feeder that tripped the 6A coal pulverizer. PSNH tried to duplicate the conditions during the trip but was

unsuccessful in inducing a trip. The unit was returned to service. As a note, no further problems have been recorded at this equipment.

G

7/6/11 – 3.2 days

The unit was taken off-line due to excessive water usage. A tube leak was found in the superheater and repaired. While the tube leak was being repaired, deteriorated refractory was also corrected. When the unit was hydro tested, another weeper leak was found in the superheater. The second leak was repaired and the unit returned to service.

H

7/11/11 – 0.0 days

The unit was in cold start mode (available in eight hours). ISO-NE had called for the unit at 10:30 PM the prior evening for an online time of 5:00 AM. Even though the start-up notice was only 6.5 hours, PSNH accepted the bid. PSNH was not able to phase the unit until 6:00 am resulting in a delayed start, but still making its 8-hour start time designation.

PSNH states that many times the ISO-NE calls for unit start-up shorter than the eight-hour requirement and that PSNH always does its best to satisfy the pool needs by phasing as soon as possible. There appears to be some misunderstanding between PSNH and the ISO-NE that what should have been a best efforts start-up became a PSNH commitment. PSNH should make clear to all operators and ISO-NE that start-up requests shorter than committed start-up time requirements are on a best efforts basis only.

I

8/8/11 – 0.8 days

The unit was leaking a small amount of hydrogen from the generator hydrogen cooler and the leak was being monitored. The unit has four hydrogen cooler bundles and the leak was isolated to cooler #3. PSNH took the unit out of service at the most economic time, found and repaired a single tube leak in cooler #3, and returned the unit to service.

J

9/26/11 – 0.0 days

The unit tripped when the 32TT relay tripped the unit on low turbine steam flow during start-up. As noted above (see Outage 4E), the 32TT performs a similar function to the reverse power relay. In this case, the 32TT relay is also used as a low turbine steam flow indicator (as there is no steam flow indicator) and is set to trip at 5 MW. The operator phased the unit somewhere between 3 MW and 5 MW and the unit tripped. The operator recognized what had happened and took corrective action to re-phase the unit. The unit returned to service when steam flow was above 5 MW.

The operator involved was a new operator and just recently trained on phasing the unit prior to this outage. PSNH discussed the event with the operator.

K
10/1/11 – 0.3 days
This outage was taken to prepare for the Schiller starting station service (used during unit start-up) replacement project scheduled to be done during the Unit 4 maintenance outage. Because the Unit 4 and Unit 6 station service interface at the primary voltage level, the Unit 6 station service was required to be isolated. The station service was isolated and the unit returned to service.

L
10/17/11 – 0.0 days
The unit was taken out of service 15 minutes earlier than its scheduled shut down time because the unit ran out of fuel. As part of the make-ready process to ensure that units that may be on economic reserve shutdown for extended periods of time are able to start when requested, PSNH now empties the coal bunkers when such a condition is likely to exist. PSNH estimates the amount of coal in the bunker, BTU content, and run rate to determine when to stop adding coal to the bunker. In this case, the calculation was 15 minutes off.

M
10/19/11 – 0.1 days
When preparing for the unit to come on-line, both the induced draft and forced draft fans must be running. When the primary air fan is started it boosts furnace pressure with a bump. In this case when the primary air fan was started (start #1) the furnace pressure increased too much and tripped the induced draft, forced draft, and primary air fans.

When the starting the primary air fan, the forced draft fans are reduced to make room for the input from the primary air fan. The reduction is dependent on specific operating conditions at the time so there are no detailed operating values specified. The operator cut the reduction in airflow too close and all fans tripped as noted above. The fix in this case was to restart the fans with the induced draft fans started first in the starting sequence. When restarted (start #2), the induced draft fan tripped after a few seconds of operation. PSNH tried to start the induced draft fan again (start #3) without success. At that point, PSNH was prevented from starting the motor again for 30 minutes because of the new motor protection relay installed in the spring overhaul. When the induced draft fan was started (start #4), the fan ran for 20 seconds and tripped again. After that start, the motor protection relay required a one-hour delay before restart to remain within the thermal capabilities of the motor.

After the one-hour pause, a fifth attempt was made to start the motor and was successful. Investigation found that new motor protection relays installed during the spring overhaul had a more conservative-than-necessary overload curve built into the start logic. PSNH with vendor assistance, modified the overload logic to be less conservative. PSNH also stated that the issue was never discovered because the induced draft fans never tripped since the spring overhaul.

The result was that the unit sustained a delayed phasing to the system. PSNH also counseled the operator.

**Evaluation Except for Outage 6C**

Accion Group reviewed the outages at Schiller and found them either to be reasonable and not unexpected for these units and their vintage, or found them necessary for proper operation of the units. Accion Group concluded that PSNH conducted proper management oversight for these outages.

**Evaluation for Outage 6C**

PSNH attributes the tripping of the breakers to the fact that it was 10 PM at night and that it was dark in the area. Most breaker panels have breaker "on" positions that are from left and right towards the center of the panel. Dusting left to right could be done if done lightly, but increases the chance of opening a breaker if performed with excessive force. An inadvertent trip is virtually eliminated by vertically dusting the breaker panels up and down. An operator with a reasonable understanding of the breaker panel function in relation to his/her duties and a reasonable attention level would recognize this. Accion attributes this outage to inattentive operator action. As such, PSNH should reinforce its expectations of attentiveness to its operators. Accion recommends that the replacement power costs associated with this outage not be recovered from customers.

**Recommendations**

Accion believes that PSNH more than likely will be using increased amounts of used or refurbished equipment as its unit fleet ages. Accion recommends that PSNH add to the part's history documentation, the testing performed on that particular part. Such nomenclature could be "functional, manufacturer, etc." and should include new parts also. This recommendation should be implemented at all stations, and the hydro group and PSNH expectations be made clear to vendors.

Accion recommends that PSNH make clear to the ISO-NE that all unit starts are made on a best efforts basis only if the start-up time is less than the committed start-up time.

## Hydroelectric Unit Outages For 2011

The following section describes the outages at PSNH's hydroelectric ("hydro") stations during 2011. The outage durations listed have been stated as the actual duration of the total outage regardless of whether there was water to run the unit. Accion Group, Inc. ("Accion" or "Accion Group") indicates water availability during any portion of the outage by a "Y" or "N" next to the outage designation. In order to simplify the outage descriptions, a separate outage description appears as "M" where multiple units were out of service for the same duration and reason. If the multiple unit outages are not returned to service within an hour of each outage, the outages are separated into and as reported as single unit outages.

In 2011, due to more rainfall than the average water year, the PSNH hydro fleet generated 368,500 MWh of energy, which is 7% more than the 344,500 MWh in an average water year. This level of generation was achieved despite the largest unit on the system (Smith) out of service for a period of four months where an estimated 48,000 MHh of generation was lost. Maintenance schedules were revised to accommodate additional flow wherever possible.

In 2011, there were 23 hydro unit outages caused by distribution system disturbances. Additionally, there were no independent transmission disturbances that resulted in hydro generation outages in 2011.

### Amoskeag Station

Major planned projects at Amoskeag station in 2011 included the inspection and repair of the trash racks, plugging of the east side flood gates, and commencement of the east side eel passage project.

**Multiple Unit Outages**
M-A
Units #1 and #2
7/14 – 0.1 days – Y
Unit #1 and Unit #2 at Amoskeag have black start capability and must demonstrate that capability to the Independent System Operator (ISO-NE) each year. The units were taken off-line, successfully completed their tests, and returned to service.

M-B
Units #2 and #3
9/8 – 0.1 days – Y
The units tripped off-line when the emergency generator automatically started for its weekly test. When the emergency generator starts, all station loads are transferred to the emergency

generator via the automatic transfer switch. PSNH found this transfer switch to be unreliable on 2/27/12 in that it would not transfer back to normal operating mode automatically. On 4/19/12, PSNH had Onan Generator Services further troubleshoot the switch. The switch was found to have a bad limit switch and a new switch was ordered. A new limit switch arrived on 9/17/12 and will be installed at the next available opportunity.

While waiting for the new limit switch, PSNH made a temporary program change to the transfer switch requiring operator action to switch the generator from emergency mode to normal supply. This action retains the black start capability of the station.

**Amoskeag - 1**

A

1/10/11 – 8.3 days – N

This planned five-day outage was taken to perform the annual inspection of the unit. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. The water flow was low at this time and the generator was not needed for power production. PSNH diverted manpower to other locations where outage timing was more important. PSNH's approach increased the time of the outage to perform the scope of work.

B

6/7/11 – 0.1 days – N

The unit failed to start when requested to do so. PSNH started an alternate unit. Investigation revealed that the coil on the 65S2 switch had a burnt open coil. The 65S2 allows governor oil pressure to be applied to the wicket gate servo motor to open the wicker gates, allowing water to flow through the turbine. The coil was replaced, passed testing, and the unit was returned to service. PSNH determined that the coil failed because it was at the end of its useful life.

C

12/24/11 – 0.2 days – Y

The unit tripped when the 65SX2 switch coil failed in service. The 65SX2 switch picks up the 65S2 switch, described above, allowing its start-stop solenoid to become energized. The coil was replaced, passed testing, and the unit was returned to service. PSNH determined that the coil failed because it was at the end of its useful life.

**Amoskeag – 2**

A

2/14/11 – 4.3 days – N

This planned five-day outage was taken to perform annual inspection of the unit. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

B

2/23/11 – 0.1 days - Y

The unit was taken out of service to conduct testing of the unit's braking system. Operators noticed that the unit would not come to a full stop when shut down. Investigation found that the governor was not going to zero gate, not shutting off water flow, and thus prevented engagement of the braking system due to debris caught in the wicket gates. The unit was operated manually to release the debris. PSNH stated that the intake screen had been inspected, was found to have holes, and replacement is scheduled in 2012.

C

6/23/11 – 0.3 days - N

The unit was taken out of service to repair an oil leak on the governor gate lock piston. Oil seals and rings were replaced on the piston and the unit returned to service. See Outage D, below.

D

7/7/11 – 0.3 days – N

The unit was taken out of service as there was still a small oil leak found in the area of the hydraulic gate lock. A leak was found at the hydraulic valve on the gate lock. A new valve was ordered on overnight availability and the unit returned to service. See Outage E, directly below.

E

7/8/11 – 0.2 days – N

The unit was taken out of service to install the new hydraulic valve on the gate lock. The valve was installed and the unit returned to service. See Outage D, directly above.

**Amoskeag – 3**

A

1/5/11 – 0.1 days – N

The exciter brushes were arcing, requiring a closer inspection and cleaning of the brushes. The unit was taken off-line and replaced with another unit. The exciter, brushes, and brush holders were cleaned and inspected. When work was completed, the unit returned to service.

B

2/22/11 – 7.0 days – N

This four-day planned outage was taken to perform the annual inspection of the unit. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. The water flow was low at this time and the generator was not needed in-service to capture the existing flow. PSNH diverted manpower to other locations where outage timing was more important. PSNH's approach increased the time of the outage to perform the work scope.

C
8/15/11 – 0.1 days – N
Results of the 1/31/11 oil sampling indicated slightly higher concentrations of lead and copper than desired in the lower guide bearing oil. The unit was taken out of service at this time because there was insufficient water to run the unit, the oil was replaced, and the unit was returned to service.

D
9/13/11 – 0.1 days – N
PSNH lowered the pond level to that of the dam crest for safety purposes in order to replace the flash boards. By FERC license, PSNH can only refill the pond at a rate equal to 10 % of the inflow value. After the flashboards were repaired, the unit was removed from service to meet the FERC refill requirement. When the pond refilled, the unit was returned to service.

E
9/25/11 – 0.3 days – Y
The unit was taken off-line by the pond control system. The bladder at the dam (inflatable flash board section) had lowered and the pond control system activated when the low head water height was reached. PSNH manually raised the bladder to its appropriate level. Investigation found that the transducer for the bladder height was out of adjustment. PSNH adjusted the bladder height transducer, visually verified that the bladder returned to its proper height, and returned the unit to service.

The transducer is attached to a cable suspended over the gatehouse. Where adjustment to the transducer has been routinely required, PSNH has made changes to the pond control Programmable Logic Controller (PLC) that allows for quicker unit response to pond level.

F
10/30/11 – 1.0 days – Y
The unit tripped. PSNH was unable to pinpoint a cause either from within the plant or externally. The unit returned to service after the investigation was completed.

**Ayers Island**

Major planned projects at Ayers Island for 2011 included the completion of dam reinforcement, FERC's changed earthquake remediation measures, and the fabrication of a new draft tube for Unit #3 that will be installed in 2012.

**Multiple Unit Outages**
M-A – (Related to a T&D event)
Units #1 through #3
6/2/11 – 0.1 days – Y
A tree outside the 115 kV right-of-way caused a fault on the E-115 line while the A-111 line was out of service for planned work. PSNH states that relay operations were correct and that the tree in question was not identified as a danger tree or flagged as a potential problem during the last inspection in 2006. The tree was cleared and the system was returned to a state where the units could return to service.

Accion notes that PSNH states that they have not addressed danger trees that were off the right-of-way.

M-B – (Related to a T&D event)
Units #1 and #2
11/23/11 – 0.0 days – Y
The units tripped due to a tree coming in contact with the 345 34.5 kV line that was located outside of the right-of-way. This tree was not identified as a hazard tree during the last inspection in 2006. The tree was removed and the units returned to service.

Accion notes that PSNH states that they have not addressed danger trees that were off the right-of-way.

**Ayers Island – 1**
A
1/17/11 – 4.4 days – N
This planned five-day outage was taken to perform the annual inspection of the unit. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. The work scope was completed within the outage time and the unit returned to service.

B
2/3/11 – 0.0 days – Y

There was not enough water to run the unit after it returned from its annual overhaul in Outage A, above, until this time. Once operating, the unit tripped due to high oil level in the lower guide bearing reservoir. 2½ gallons of oil was removed from the lower guide bearing reservoir to bring the oil back to a normal operational level.

PSNH's procedures require that when oil is removed from the reservoir, it is measured and the same volume of oil is replaced. Oil levels are monitored when the unit returns to service. PSNH's investigation found that during the annual inspection in Outage A, above, too much oil was added due to inaccurate measurement.

C
11/17/11 – 0.0 days – Y
The unit tripped on low operating output limit while conducting annual System Control and Data Acquisition (SCADA) point testing. SCADA testing is performed to validate the circuits and the output limit set points to maximize unit flexibility. The existing low operating output limit was used as a starting test point in this test, as that point was validated the previous year. Testing must be conducted to ensure valid operating limits are available to operations.

D
11/18/11 – 0.0 days – Y
The unit tripped again on low operating output limit while conducting annual SCADA point testing. A new and higher low operating output limit was used as a test point in this test. Testing must be conducted to ensure valid operating limits are available to operations, and pulse changes of approximately 200 kW are made. However, when operating at the low end of unit output, a small change in river flow or governor fluctuation can result in a unit trip.

**Ayers Island – 2**

A
1/31/11 – 11.4 – N
This planned five-day outage was taken to perform the annual inspection of the unit. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. The water flow was low at this time and the generator was not needed to capture the existing flow. PSNH diverted manpower to other locations where outage timing was more important. PSNH's approach increased the time of the outage to perform the work scope.

B
2/14/11 – 0.0 days – N
The unit was taken out of service to cut in and test extra wiring modifications made during the annual maintenance overhaul in Outage A, directly above, that separated the spider and thrust

bearing oil flow and temperature indications. This work was not part of the annual maintenance outage scope and was completed when the unit was available. The testing was completed and the unit returned to service.

C
2/14/11 – 0.2 – N
During the start-up from Outage B, above, it was noticed that the electronic overspeed switch was not performing properly. Investigation found that the switch was bad. PSNH ordered a new electronic overspeed switch, disabled the electronic overspeed system, and returned the unit to service using the manual overspeed system.

When the electronic switch for Amoskeag was received, the switch was diverted and installed at Canaan to reinstate the auto phase feature at that location. An additional electronic switch was ordered for Unit #2 and is currently on backorder.

D
6/21/11 – 0.1 days – N
The unit tripped due to a high thrust or spider bearing temperature (indication is coupled). A check of the bearing temperatures showed no high temperatures. PSNH thought that a momentary loss of oil to the one of the bearings could have triggered the unit trip. PSNH removed the bearing oil flow switch from its place in parallel with the shutdown string logic, reconnected it to a Programmable Logic Controller, and introduced a 60-second time delay into its trip function, thus allowing a "ride through" of oil flow transient events. If such an event continues to occur in the future, the one-hour shutdown timer will initiate shut-down as it is programed to do.

PSNH states that this issue is a carry-over from the Garvins 4 October 2010 exciter fire lessons learned, and installations are being implemented at all other hydro facilities to separate these functions.

E – (Related to a T&D event)
8/19/11 – 0.0 days – Y
A lightning strike on the V-182 115 kV line from Garvins to Webster resulted in an incorrect overtrip operation trip/reclose of the E-115 115 kV line (north of the Pemigewasset tap). PSNH notes that this overtrip has happened before. PSNH ultimately determined that the original relay equipment installed had a manufacturing defect that resulted in intermittent problems. Setting changes made as a result of the first incorrect operation in 2010 could not address the current misoperation because the equipment was defective. The relay equipment has since been replaced.

F

8/28/11 – 0.7 days – Y

The unit tripped during Tropical Storm Irene when many system disturbances were occurring simultaneously. PSNH's investigation found that a 0.45 pu[1] voltage sag occurred at the Pemigewasset substation for 0.45 seconds. PSNH could find no evidence that a disturbance occurred on either the transmission or distribution system that correlated with this event. After investigation, the unit was returned to service.

**Ayers Island – 3**

A

1/21/11 – 0.1 days – Y

A suspected bad relay on Unit #1 was being investigated by PSNH. During the troubleshooting, the DC control power switch was inadvertently opened on Unit #3. The relays were reset and the unit was returned to service.

PSNH stated that these cabinets were not labeled from behind on an individual unit basis. PSNH also states that the operator checked the front of the cabinet for labeling prior to entering the rear of the cabinet and operating the switch. PSNH checked the entire station and found no similar areas without front labeling and proper reverse labeling behind the cabinet. PSNH also checked other hydro stations and found no deficiencies in labeling in this regard. Accion attributes this outage to operator confusion resulting in error, and has labeled the rear of the cabinet.

B

2/15/11 – 0.0 days – N

The unit was taken out of service to cut in and test extra wiring modifications made that separated the spider and thrust bearing oil flow and temperature indication. This work was completed when the unit was available. The testing was completed and the unit returned to service.

C

[1] Per Unit is the term industry uses to normalize variables. In this instance a 0.45 pu voltage sag means that the voltage sagged to 45% of the normal 34.5 kV value.

2/16/11 – 0.2 days – Y

The unit tripped off-line due to low bearing #38 oil flow, high bearing #38 temperature, and loss of field provided as annunciator targets. Unit #2 was started to take this unit's place in the dispatch order. PSNH was not able to determine the cause of this trip and the multiple targets received. PSNH reset the targets and returned the unit to service. PSNH reports that there have been no similar problems since that time.

D

8/21/11 – 0.0 days – N

The unit was not operating when several alarms were received. PSNH's troubleshooting revealed no cause. PSNH reset all alarms and returned the unit to service. PSNH notes that there were lightning storms in the vicinity, but was not sure if they contributed to the outage.

E

8/23/11 – 0.5 days – Y

The unit was requested to start on 8/22/11 after the pond had been drawn down prior to an up-coming rainstorm. To refill the pond, this unit was commanded to stop and when it did it went to a "no go" position because of reverse power conditions. When the operator arrived, an additional attempt to start the unit resulted in another trip on reverse power.

The investigation revealed that the phase sequence under voltage flag was not reset from Outage D, directly above. PSNH was unable to determine why the phase sequence under voltage flag was not reset. The directional power relay card and its fingers were cleaned, adjusted, and tested. The unit was restarted and returned to service.

F

9/29/11 – 1.3 days – Y

For diver safety, the unit was taken out of service to complete a Non-Destructive Examination (NDE) inspection of the Unit #3 draft tube and to take dimensions for the new draft tube that will be constructed in 2011 and installed in 2012.

**Canaan**

Major projects completed at Canaan in 2011 included inspection and painting of the surge tanks, installation of a Tuff Boom (screen attached to a floating barrier) system at the intake, and concrete repairs on the downstream side of the powerhouse.

**Canaan – 1**

A

2/22/11 – 0.3 days – Y

This outage was scheduled to reinstall and test the auto phasing function of the unit. Auto phasing allows for three restarts if the unit fails to stay on line for five minutes. The auto phasing system was shut off in 2010 because it was not working properly and the unit has been phased manually since that time. The electronic switch and a replacement governor gate limit motor were installed, tests were made, and the unit returned to service with remote phasing capability.

B – (Related to a T&D event)
3/18/11 – 0.1 days – Y
A minor storm was in progress at this time accompanied by windy conditions. The 355 34.5 kV line tripped and reclosed causing the unit to trip. PSNH patrolled the line, found no reason for the operation, and returned the unit to service.

PSNH identified 36 danger trees both within and outside of the right-of-way in 2011 during the NHPUC requested patrol. Any tree posing an imminent threat to the operation of the line was removed at that time and the remaining trees will be addressed during the 2013 mowing cycle. In addition, PSNH plans to re-patrol the line in late 2012 to capture additional danger trees that have developed since the 2011 patrol.

C – (Related to a T&D event)
4/21/11 – 0.2 days – Y
The 355 34.5 kV line tripped and reclosed due to contact from a small pine tree. PSNH found a tree resting on the neutral conductor (which had contacted the phase conductor), removed the tree, and returned the unit to service.

D – (Related to a T&D event)
5/26/11 – 0.1 days – Y
The D-142 115 kV line between the Whitefield to Lost Nation substations line tripped due to contact from a tree outside of the right-of-way. PSNH states that the tree was not identified as a danger tree or a potential threat during the 2009 right-of-way (ROW) inspection. During the 2009 inspection, PSNH identified five locations where vegetation needed to be corrected within the right-of-way and did so in 2009 and 2010. PSNH also states that it performed side trimming of this line in 2010.

Accion notes that PSNH states that they have not generally addressed danger trees that were off the right-of-way.

E – (Related to a T&D event)
5/27/11 – 0.0 days – Y
There was a lightning storm in the area at the time. The 376 34.5 kV line from Lost Nation to Whitefield experienced a lightning strike. When the line tripped, the unit tripped. This is an

overtrip condition. Upon investigation, PSNH found that the Whitefield end reclosed as designed, but that the Lost Nation end had a faulty breaker-close mechanism. Once the issue was identified, the unit returned to service, and the breaker closure mechanism was repaired.

F – (Related to a T&D event)
6/1/11 – 0.1 days – The 376 34.5 kV line between the Lost Nation and Whitefield substations tripped causing the unit to overtrip. A tree from outside of the right-of-way was found on the line. The tree was removed and the unit returned to service.

PSNH states that it generally does not perform inspections off of the right-of-way. The last inspection for line 376 was 2010, and hazard trees identified within the right-of-way were addressed during vegetation maintenance follow-up.

G – (Related to a T&D event)
6/3/11 – 0.0 days – Y
The unit tripped and the hydro outage report indicated that there was a fault on the station service line. No dispatcher interruption reports or distribution trouble reports were generated at this time. Line crews were dispatched, but nothing was found that could explain the trip. The unit was automatically phased in five minutes according to the automatic phasing sequence logic.

H
8/1/11 – 10.4 days – Y
This planned 12-day outage was taken to perform the annual inspection of the unit. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. The critical path of the outages was the painting of the surge tank, which required a longer outage than the normal five-day overhaul.

I – (Related to a T&D event)
12/8/11 – 0.1 days – Y
A minor storm was in progress in the area when the unit tripped. PSNH found a tree on the line at pole 3/44 on the 355X10 distribution circuit. The tree was removed and the unit returned to service.

**Eastman Falls**

The major projects completed at Eastman Falls in 2011 included preparation for FERC relicensing, fabrication of fish louvers for installation in 2012, and extensive work on the wicket gate arms and Bestobell seal on Unit #2.

**Multiple Unit Outages**

There were no multiple unit outages at Eastman Falls in 2011.

**Eastman Falls-1**

A

11/28/11 – 4.4 days – Y

This planned five-day outage was taken to perform the annual inspection of the unit. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

B

12/19/11 – 0.3 days – Y

The unit phased as requested but immediately tripped on reverse power because the governor failed to stop. Investigation found that the switch to the speeder spring motor (controls governor speed) was faulty. PSNH cleaned, lubricated, and exercised the switch. The unit was started and stopped four times to ensure proper operation and was then returned to service.

**Eastman Falls – 2**

A

6/6 – 43.3 days – Y

This planned 49-day outage was taken to perform the scheduled annual inspection of the unit. The straight time schedule was developed after input from PSNH Hydro, PSNH Generation Maintenance, and vendors that would be providing outage support. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. In addition, extensive repairs were made to the wicket gate arms and shifting ring (connects to the wicket gate arms, and was binding and sticking above the 90 percent set points) plus a complete inspection of the Bestobell seal.

During the outage, PSNH found that the problem was not the shifting ring, but that barnacles and rust had built up at the wicker gates which are located at the Bestobell penstock. PSNH further found that lead paint was used in the construction of the Bestobell and had to mitigate that situation before work could commence. The work scope was completed and the unit returned to service ahead of schedule.

B

8/18/11 – 0.1 days – Y

The unit was taken out of service to change the filters at the lube and hydraulic oil tank. PSNH had been having problems with water incursion into the lube and hydraulic oil system that frequently fouled the filters. In 2010, PSNH designed an oil/water separator that could remove the estimated 30 gallons of water per day that could accumulate in the system and installed the system on 12/16/10.

It appears to PSNH that the oil/water separator did not fully resolve the issue in that the separator cannot keep up with the volume of water, at times penetrating the separation seals. PSNH has been unable to correlate river flow or other unit conditions to the amount of water intrusion, and believes that it exceeds the 30 gallon per day design under some conditions. While outages like the instant outage are required to change the filters, PSNH states that the multitude of trips due to this issue have been eliminated. See outages C, D, E, and F, below.

PSNH plans to continue its work to mitigate this issue. The lube and hydrolytic systems are one system in the design of this unit. PSNH plans to install redundant filters in 2012 that can be valved so that taking the unit off-line will not be necessary to service the filters in the future.

C

8/26/11 – 0.1 days – Y

The unit was taken out of service to change the filters at the lube and hydraulic oil tank. The filters were changed and the unit returned to service. See Outage B, above.

D

9/3/11 – 0.1 days – Y

The unit was taken out of service to change the filters at the lube and hydraulic oil tank. The filters were changed and the unit returned to service. See Outage B, above.

PSNH believed that the Bestobell seal was stuck allowing water to enter the lube/hydrolytic oil system. PSNH changed its procedure and had operators drain water from the hydraulic oil tank on a daily basis. PSNH also revised its procedure to include exercising the Bestobell seal and resetting the seal pressure to between 7 and 9 psi during each filter event.

E

9/41/11– 0.0 days – Y

The unit was taken out of service to change the filters at the lube and hydraulic oil tank. The filters were changed, the Bestobell seal was exercised and reset, and the unit returned to service. See Outage B, above.

F

9/10/11 – 0.0 days – Y

The unit was taken out of service to change the filters at the lube and hydraulic oil tank. See Outage B, above. The operator ran the Bestobell pressure up and down eight to ten times until the Bestobell seal was not sticking. The operator reset the Bestobell seal pressure between 7 and 9 psi and returned the unit to service.

G – (Related to a T&D event)
10/30 – 0.3 days – Y
The unit tripped during the October 2011 snowstorm and multiple operations were occurring in the area. PSNH could not identify any system operations that would explain this outage. When the storm quieted down, the unit was returned to service.

H
10/31 – 0.0 days – Y
The unit was taken out of service to change the filters at the lube and hydraulic oil tank. See Outage B, above. The filters were changed, the Bestobell seal was exercised and reset, and the unit returned to service.

I
11/15/11 – 0.0 days – Y
The unit was taken out of service to change the filters at the lube and hydraulic oil tank. See Outage B, above. The filters were changed, the Bestobell seal was exercised and reset, and the unit returned to service.

J
11/19/11
– 0.1 days – Y
The unit tripped due to high hydraulic oil level that exceeded the trip setting at the lube and hydraulic oil tank. See Outage B, above. The filters were changed, the Bestobell seal was exercised and reset, and the unit returned to service.

K – (Related to a T&D event)
11/23/11 – 0.2 days – Y
The unit tripped during a heavy wet snowstorm and multiple operations were occurring in the area. PSNH could not identify any system operations that would explain this outage. When the storm quieted down, the unit was returned to service.

L
11/27/11 – 0.0 days – Y
The unit was taken out of service to change the filters at the lube and hydraulic oil tank. The filters were changed, the Bestobell seal was exercised and reset, and the unit returned to service. See Outage B, above.

M

11/28/11 – 0.0 days – Y
The unit was taken out of service because the operator, while preparing for the annual overhaul of Unit #1, switched out the Unit #2 control panel instead of the Unit #1 control panel. This error did not trip the unit but did require that the unit be taken out of service to reset the PLC logic. The logic was reset and the unit returned to service.

PSNH states that the panels were marked, that the event was due to operator oversight, and that the operator has been counseled.

N
12/1/11 – 0.1 days – Y
The unit tripped due to high hydraulic oil level at the lube and hydraulic oil tank. The lube and hydraulic oil level is also alarmed. An alarm was received but the unit tripped prior to operator arrival. The filters were changed, adjustments were made to the Bestobell seal pressure, and the unit returned to service. See Outage B, above.

O
12/12/11 – 0.0 days - Y
The unit was taken out of service to change the filters at the lube and hydraulic oil tank. The filters were changed, the Bestobell seal was exercised and reset, and the unit returned to service. See Outage B, above.

**Garvins Falls**

Major work at Garvins Falls in 2011 included the replacement of the stairs to the weir monitoring pool, repairs to the weir monitoring pool, and a canal drawdown to inspect the intake canal and headworks.

**Multiple Unit Outages**
M-A
Units #1 and #3
1/12/11 – 0.0 days – Y
The pond control system signaled that a unit needed to come off-line to control the pond to its proper level. Both Units #1 and #3 tripped when only Unit #1 should have tripped. PSNH found that a very narrow tolerance of the bandwidth parameters between the two units existed. PSNH restarted Unit #3 for proper flow control and adjusted the bandwidth between Unit #1 and #3. Also see Outage 1A, below.

M-B

Units #1 through #4
5/4/11 – 0.0 days – Y
FERC requires that the fish louvers have to be installed and operational by April 1st or when the flashboards are installed. PSNH shut the station down at this time to meet that FERC requirement as a crane on site for another project could be utilized.

M-C
Units #1 and #2
6/3/11 - 0.1 days – Y
These units were shut down to ensure diver safety while the lower cells of the fish louvers were installed.

M-D
7/18/11– 22.3 days – Y
Units #1 through #4
This planned 26-day outage was taken to dewater the canal, inspect the canal walls, and dredge the canal. In addition, the annual inspections of Unit #1 through #3 were performed. The straight time schedule was developed after input from PSNH Hydro, PSNH Generation Maintenance, and vendors that would be providing outage support. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. The annual inspection of Unit #4 was not done at this time as it was completed during the exciter problem that occurred in 2010. Canal work dictated the critical path of the outage.

M-E – (Related to a T&D event)
Units #1, #2, and #4
9/5/11 – 0.2 days – Y
During Tropical Storm Irene, a fault occurred on the Unitil system due to wind and subsequently tripped the units. The fault was cleared and the units returned to service.

M-F
Units #1, #2, and #4
10/13/11 – 0.0 days – Y
The units were taken off-line to support the installation of a new trash diverter called a Tuff Boom. Diver work required these safety precautions. The boom exists upstream of the intake structure and prevents trash from entering the intake structure. This particular phase of the work was completed and the units returned to service.

M-G
Units #1, #2, and #4
10/13/11 – 0.0 days – Y

The units were taken off-line to support the installation of the new Tuff Boom trash diverter. Diver work required these safety precautions. This particular phase of the work was completed and the units returned to service.

M-H
Units #1, 2 and #4
10/13/11 – 0.1 days – Y
The units were taken off-line to support the installation of the new Tuff Boom trash diverter. Diver work required these safety precautions. This particular phase of the work was completed and the units returned to service.

M-I
Units #1 through #4
10/21/11 – 0.0 days – Y
The units were taken off-line to collect and remove excessive debris collected along the fish louver line due to high river flows bringing a large amount of debris into the canal. The Tuff Boom flipped over after being hit by large trees etc., allowing a large amount of debris to enter the intake canal. The debris was removed and the units returned to service.

M-J
Units #1 through #4
10/28 /11– 0.0 days – Y
The units were taken off-line to collect and remove excessive debris collected along the fish louver line due to high river flows bringing a large amount of debris into the canal. The Tuff Boom flipped over after being hit by large trees etc., allowing a large amount of debris to enter the intake canal. The debris was removed and the units returned to service.

Accion notes that PSNH is working with the boom vendor on ways of stabilizing the screens and keeping them from flipping over.

M-K
Units #3 and #4
12/11/11 – 0.1 days – Y
The dispatcher received a trash rack differential (delta water level alarm from both sides of the trash rack indicating pluggage) alarm for Units #3 and #4. The operator ran Unit #3 and #4 in the motor mode to place back pressure on the trash rack. The rack differential alarm came in again and the operator repeated the process. Further investigation revealed that the rack differential alarm needed to be adjusted. Adjustments were made and the units were returned to service.

M-L
Units #1 through #4
12/21/11 – 0.0 days – Y
The units were shut down to remove the remainder of the fish louver equipment for the winter. The equipment was removed and the units returned to service.

M-M
Units #1 through #4
12/21/11 – 0.1 days – Y
The units were shut down to remove the remainder of the fish louver equipment for the winter. The equipment was removed and the units returned to service.

M-N
Units #1 through #4
12/22/11 – 0.1 days – Y
A scheduled station outage was taken to complete the annual black testing of Units #3 and #4. Tests were successfully completed and the units returned to service.

**Garvins Falls-1**

A
1/12/11 – 0.1 days – N
After the operator made adjustments to increase the bandwidth between Unit #1 and #3 in Outage M-A, above, to allow proper sequencing of the units from command of the pond control system, the pond control system requested that Unit #1 start. It did not do so. Unit #3 started in its place. PSNH found that the actuator would not allow the Unit #1 gate positioner to move to the proper gate setting and, thus, the unit could not come up to proper phasing speed. Further adjustments were made to the gate settings, the operator started Unit #1 manually, and the unit returned to service. See Outage 1B, below.

B
1/13/11 – 0.0 days – N
PSNH required this outage to make further adjustments to the actuator so the gate positioner would move to the proper gate setting.

C
2/15/11 – 0.2 days – N
This planned shutdown was taken to inspect the internal gears of the speed increaser. Upon inspection, it was determined that the speed increaser needed to be overhauled. Because of the similar hours on the Unit #2 speed increaser, PSNH ordered rebuild kits for both Unit #1 and

#2. The Unit #1 overhaul was planned to be completed during the July canal dewatering outage and Unit #2 was planned to be done at some time in the future. After the inspection was made, the unit was returned to service.

D – (Related to a T&D event)
8/28/11 – 0.0 days – Y
During Tropical Storm Irene, a fault occurred on the Unitil system due to wind and subsequently tripped the unit. The fault was cleared and the unit returned to service.

**Garvins Falls – 2**

A
6/1/11 – 0.0 days – Y
The unit was taken out of service to replace the switch for the governor actuator hydraulic pump motor that had been sticking in the open position. The switch was replaced, tested, and the unit returned to service.

B
8/9/11 – 15.2 days – Y
The unit was taken out of service to overhaul the speed increaser because of the similar number of hours of operation as Unit #1. After the canal drawdown outage, Outage M-D, above, which included the repair of the Unit #1 speed increaser, PSNH decided to repair the Unit #2 speed increaser at this time because the rebuild kits were on site, the special tooling was on site for the Unit #1 work, and flows were sufficiently low enough so that significant economic penalties would not be occurred.

C
8/28/11 – 0.2 days – Y
During Tropical Storm Irene the unit tripped and reclosed. PSNH was unable to pinpoint a cause either from within the plant or externally. The unit returned to service after the investigation was completed.

**Garvins Falls – 3**

A
3/30/11– 0.1 days – Y
The unit tripped off-line due to high oil level in the lower guide bearing oil reservoir. Investigation found that the Mercoid start/stop switch (mercury bulb) for the lower guide

bearing oil pump was out of adjustment. PSNH adjusted the bulb on the Mercoid switch, tested the switch, and returned the unit to service. PSNH also ordered "Reed" replacement switches at this time. See Outages B and C, below.

B
4/10/11 – 0.1 days – Y
The unit tripped off-line due to high oil level in the lower guide bearing oil reservoir. Investigation found that the Mercoid start/stop switch for the lower guide bearing oil pump failed. PSNH adjusted the bulb on the Mercoid switch, tested the switch, and returned the unit to service.

PSNH states that, since 2008, New Hampshire law has prohibited PSNH from buying new Mercoid switches. PSNH can purchase some spare parts for the Mercoid switches and is phasing out the use of these switches on a case-by-case basis. See Outage C, below.

C
4/14/11 – 0.1 days – Y
The unit tripped off-line due to high oil level in the lower guide bearing oil reservoir. Investigation found that the Mercoid start/stop switch for the lower guide bearing oil pump failed. PSNH adjusted the bulb on the Mercoid switch, tested the switch, and returned the unit to service.

Accion notes that the replacement switches ordered in Outage A, above, were received and were replaced during the canal drawdown outage in Outage M-D, above.

D
7/5/11 – 0.1 days – N
The unit was requested to start by the pond control system, but failed to do so. Unit #2 was called upon to handle the increased load. PSNH put Unit #3 on-line manually for troubleshooting, tested the start chain, found it to be working appropriately, and returned the unit to service.

E – (Related to a T&D event)
8/28/11 – 0.1 days – Y
During Tropical Storm Irene, a fault occurred on the Unitil system due to wind and subsequently tripped the unit. The fault was cleared and the unit returned to service.

**Garvins Falls – 4**

A
1/1/11 – 32.6 days – Y

This outage is the continuation of the thrust bearing outage reported as Garvins Outage 4D in Docket DE 11-094. Accion reports outages that overlap calendar years in the year that the majority of the outage days occur. Where 110.2 outages days of this outage occurred in 2010, the outage was reported, discussed, and recommendations made during Docket DE 11-094. This outage needs no further discussion here.

B
5/26/11 – 0.0 days – Y
The unit tripped due to a high lower guide bearing temperature. The operator responding to the outage reported a building air ambient temperature of 113$^{o}$F. The operator opened the doors of the building and restarted the unit.

PSNH states that the fan/louver system was on winter settings and that record high temperatures were not expected so early in the year. PSNH dispatched an operator when the alarm was first received, but the lower guide bearing reached trip level prior to arrival. PSNH states that it is evaluating enhancements to this system. Accion suggests that PSNH include increasing the time period considered to be “summer” in its evaluation or eliminate the winter period altogether.

C
5/27/11 – 0.0 days – Y
The unit was taken off-line due to low oil level in the lower guide bearing oil reservoir. PSNH suspected a sticky Mercoid switch. The switch was lubricated and cycled several times before returning the unit to service.

D
5/27/11 – 0.0 days – Y
The unit tripped due to low oil level in the lower guide bearing oil reservoir. Further troubleshooting revealed that the Mercoid switch was not the problem, but that the lower guide bearing oil pump was not providing sufficient oil flow to the lower guide bearing. PSNH states that this valve does need to be adjusted with changing seasonal conditions. The unexpected unseasonably hot weather required that the valve allow more oil flow to maintain proper bearing temperature. The oil valve setting was adjusted and the unit returned to service.

E
5/27/11 – 0.1 days – Y
The unit tripped off-line due to high oil level in the lower guide bearing oil reservoir. PSNH made further adjustments to the outlet valve, cycled the valve, and returned the unit to service. The valve adjustment is a manual adjustment that requires an iterative approach to attain the proper valve position. Items such as changing the oil during the previous overhaul (exciter outage) most likely changed the viscosity of the oil thus forcing valve adjustments to be made.

F

5/29/11 – 0.0 days – Y

The unit tripped off-line due to low oil level in the lower guide bearing oil reservoir. The system reset itself and restarted the unit 35 minutes later because the pond level was such that the generation of this unit was required.

G

5/30/11 – 0.0 days – Y

The unit tripped off-line again due to low oil level in the lower guide bearing oil reservoir. The system reset itself and restarted the unit 35 minutes later because the pond level was such that the generation of this unit was required.

H

5/30/11 – 0.0 days – Y

The unit tripped off-line due to low oil level in the lower guide bearing oil reservoir. The system reset itself and restarted the unit 35 minutes later.

PSNH initially determined that due to the number of previous intermittent shutdowns, that the Mercoid switches were not functioning properly and ordered new Reed switches to replace them. Further investigation attributed the cause of the outage to be low oil level and require manual oil flow valve adjustments. The new switches were installed on 6/13/11.

I

7/3/11 – 0.1 days – N

The unit tripped off-line due to high thrust or spider bearing temperature. Investigation found that the trip was caused by rodent damage to control cables. Replacement of these controls cables was part of the work scope planned during the 7/18/11 dewatering of the canal outage. Damage was repaired and the unit returned to service.

J

8/18/11 – 0.0 days – Y

The unit tripped on a high thrust bearing temperature. PSNH found that both the alarm and trip points were set to 82$^{o}$C. The alarm point was reset to 90$^{o}$C and the trip point was set to 98$^{o}$C according to the bearing manufacturer's nominal 10$^{o}$C delta recommendation.

PSNH states that the device was labeled in accordance with its system wide ongoing and comprehensive labeling program expected to be completed in 2013. PSNH speculates that where the temperature location of the dials is at about waist height, they could have been bumped by an operator during his rounds.

With respect to PSNH's explanation, Accion considers it unlikely that an operator would bump both the alarm and trip temperature dials, the dials would be bumped to the exact same temperature setting, and that a seasoned operator bumping the dials with the force required to change the settings would not take action to assure that settings were not changed.

K
9/15/11 – 0/1 days – Y
The unit was taken out of service (all four units operating) to hold water at the dam crest level so the flashboards could be reinstalled. The flashboards were removed in anticipation of high flows from Tropical Storm Irene. The flashboards were reinstalled and the unit returned to service.

## Gorham

Major projects at Gorham in 2011 included the canal drawdown, dredging of the canal, replacement of the Unit #3 and Unit #4 trash racks, and concrete repairs at the upper gate house and the Unit #3 and Unit #4 trash racks.

**Multiple Unit Outages**
M-A – (Related to a T&D event)
Units #1 through #4
5/27/11 – 0.1 days – Y
There were storms in the area and both the 351 and 352 34.5 kV lines connected to Gorham tripped and reclosed due to lightning at the same time. After the system was checked, the unit returned to service.

M-B
Units #1 through #4
8/8/11 – 30.2 days – Y
This planned 31-day outage was taken to perform the scheduled annual inspection of the unit. The straight time schedule was developed after input from PSNH Hydro, PSNH Generation Maintenance, and vendors that would be providing outage support. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected In addition to the normal maintenance work, the work scope of this outage included the canal drawdown, dredging of the canal, replacement of the Unit #3 and Unit #4 trash racks, and concrete repairs at the upper gate house and the Unit #3 and Unit #4 trash racks.

M-C - (Related to a T&D event)
Units #1 through #4
9/12/11 – 0.0 days - Y
There were storms in the area and the Gorham to Whitefield 351 34.5 kV line tripped and reclosed at Whitefield only. PSNH patrolled the line and found nothing to explain the trip. The

relay systems and circuit breakers were also checked and no issues were identified. The unit was returned to service.

**Gorham – 1**
There were no single unit outages of Unit #1 in 2011.

**Gorham – 2**
There were no single unit outages of Unit #2 in 2011.

**Gorham – 3**
There were no single unit outages for Unit #3 in 2011.

**Gorham – 4**
There were no single unit outages for Unit #4 in 2011.

**Hooksett**

There were no major projects completed at Hooksett in 2011.

**Hooksett – 1**
A- (Related to a T&D event)
2/18/11 – 0.0 days – Y
The 332/335 34.5 kV line between Garvins and Rimmon tripped and locked out at Rimmon during windy conditions. Hooksett Hydro is tapped off of this line and tripped when the line tripped. PSNH patrolled the line and nothing was found. The unit was returned to service.

B- (Related to a T&D event)
2/22/11 – 0.1 days – Y
The 332/335 34.5 kV line between Garvins and Rimmon tripped and the Rimmon end reclosed under clear conditions. Hooksett Hydro is tapped off of this line and tripped when the line tripped. PSNH patrolled the line and nothing was found. The unit was returned to service.

C
9/3/11– 0.1 days – Y
The unit tripped off-line due to low oil level in the lower guide bearing. Investigation found the oil level float switch stuck in the position, so the lower guide bearing oil pump would not start. The switch was cleaned, lubricated, and tested after which the unit returned to service.

D – (Related to a T&D event)
11/1/11 – 0.1 days – Y
During the third day of restoration efforts following the October snow storm, a contractor attempted to close a cutout fuse door (closing the fuse), but the cutout door was misaligned and

failed when closed. The failed equipment caused an outage to the distribution circuit and tripped the unit. The outage was cleared and the unit returned to service.
PSNH states that the contractor properly reported the event to PSNH. It is PSNH's responsibility to enter all safety related events into the Safety Incident Reporting System (SIRS), but no entry was made in this instance. It is PSNH's expectation that all safety-related events are reported in SIRS in a timely manner by PSNH personnel. In this case, PSNH believes that the report was internally overlooked due to the significant restoration effort in progress. By not being entered into SIRS, no investigation report was requested from the contractor. Management has discussed the event with the responsible supervisor and the importance of reporting events in SIRS. In addition, the event was discussed in detail with the contractor.

Accion views this event as an employee error under the conditions of restoration.

E
12/5/11 – 4.1 days – Y
This planned five-day outage was taken to perform the scheduled annual inspection of the unit. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected.

F
12/13/11 – 0.1 days – Y
After returning from the annual maintenance outage in Outage E, above, the unit could not have certain systems tested until high tail water receded. When the unit restarted on this date, the E-SCC noticed that the unit would not go to full load. PSNH had intended to test this system on this date as part of the annual inspection follow up. Investigation found that cam on the clutch that drives the micro switches that control the governor was misaligned. The clutch was adjusted and tested and the unit returned to service.

## Jackman

The major projects completed at Jackman in 2011 included concrete repairs at the toe of the dam and the replacement of the 2400 V cable between the low side breaker and the step-up transformer.

### Jackman-1

A
7/6/11 – 0.2 days – N
This was a scheduled outage to ensure the safety of divers conducting an underwater inspection of the dam. The inspection was completed and the unit returned to service.

B – (Related to a T&D event)
9/29/11 – 0.0 days – N
A lightning strike to the 3140 34.5 kV line caused the line to trip and reclose. When the line tripped, the unit tripped. This is the type of overtrip situation currently under study by PSNH. The unit was returned to service.

C
11/15/11 – 6.2 days – N
This planned 12-day outage was taken to perform the scheduled annual inspection of the unit. A visual inspection, general cleaning, and equipment tests were performed. Both the turbine and generator were inspected. The 2400 volt cable between the step-up transformer and the breaker was also replaced during this outage. The cable work was originally planned to be completed in series with the annual inspection, but was able to done in parallel, reducing the outage time by approximately six days.

D – (Related to a T&D event)
12/8/11 – 0.2 days – Y
A tree from outside of the right-of-way fell on the L-163 115 kV line between the Keene and Jackman Substations. When this event occurred, the A-164 terminal at the Weare substation and the F-162 terminal at Greggs substation overtripped. The unit also overtripped for this fault. PSNH investigation found that there was a setting error on a relay associated with the F-162 and A-164 lines at Greggs.

PSNH states that this type of relay is checked on a six-year schedule and was installed in 2009/2010 so that it had not reached its first maintenance cycle. The incorrect setting was associated with the original installation of the Weare Substation. PSNH also states that they have not addressed danger trees that were off the right-of-way.

## Smith

Major projects at Smith in 2011 included the unplanned replacement of the failed TB66 breaker. The annual inspection was also conducted during this repair.

### Smith-1

A
5/26/11 – 0.0 days – Y
The unit tripped on a high thrust bearing temperature. The unit had alarmed but tripped prior to operator arrival. Investigation found that the bearing temperature increased because the cooling water pump tripped. The initial investigation did not determine the cause of the cooling water pump trip indicating that the problem was intermittent. The unit was returned to service and a

full inspection and repairs were scheduled to be performed during the annual maintenance outage.

B - (Related to a T&D event)
7/15/11 – 0.1 days – Y
The unit tripped when the phase one 115 kV lightning arrestor blew on TB-115 115/34.5 kV transformer at the East Side Substation in Berlin. The arrestors at this location are the silicon carbide type of arrestor and were installed over 45 years ago. PSNH believes that this type of arrestor reaches life's end at 45 to 50 years and is replacing these units on its system. PSNH replaced all three lightning arrestors at this location and the unit was returned to service. PSNH notes that there have been no other lightning arrestor failures in this area of the system in the recent past.

C – (Related to a T&D event)
9/1/11 – 120.0 days – Y
The event initiated as a 115 kV event on the short 115 kV line between Smith Hydro and the East Side Substation in Berlin (Z-177). The disturbance did not operate TB-66 (Smith 12.47 kV 2000 amp breaker operated at 6.6 kV) because the disturbance drew less current than the 364 amp bus setting that PSNH uses as a permissive prior to allowing operation of the 115 kV bus differential protection scheme at Berlin. The fault remained at or below 250 amps for an unknown amount of time. (Accion believes that the time to trip was less than 30 seconds based on the fact that the S-136 second zone relay at Whitefield or the D-142 second zone relay at Lost Nation did not operate.) The TB-66 breaker failed to open and the W-179 and S-136 115 kV breakers at Berlin opened 0.71 seconds later after the fault evolved into a bolted phase B to ground fault. There is also a ten-cycle delay in the operation of the 115 kV bus differential to allow proper coordination between the 115 kV bus and the 115/34.5 kV transformer differential protection schemes.

PSNH performed a climbing inspection of the Z-177 115 kV line and found no trace of a disturbance. Lightning arrestors at Smith were tested and passed. All equipment at the East Side Substation was tested and passed. PSNH did an internal self-assessment and could not determine the cause of the breaker's failure to open at Smith Hydro. PSNH requested that Eaton Electric do a comprehensive forensic analysis of the failed breaker. Eaton could not come to a definite conclusion as to the failure mode of the breaker. Eaton was not able to rule out failure modes related to 1) insulation failure due to surface contamination, 2) insulation failure due to increased electrical stress, 3) insulation failure due to foreign object, and 4) mechanical failure of a post insulator, with each cause by itself or in combination representing possible failure modes that are consistent with and not ruled out by the evidence.

PSNH evaluated either repairing or replacing the breaker at Smith and chose to replace the breaker due to repair schedules. The outage was expected to last for approximately 110 days, but was extended by approximately ten days due to PCB abatement that took longer than projected.

Accion notes that PSNH uses a common industry approach to bus protection. A margin is used for pickup of the bus protection impedance relays so that inadvertent trips are all but eliminated. PSNH uses industry rules of thumb when setting the impedance relays. Those rules of thumb are that the minimum available three-phase fault current must be two or more times the bus protection pickup current, and that the minimum available single phase fault current must be three or more times the bus protection pickup current. Both rules of thumb were met at the Berlin Substation.

While Eaton did not rule out any of the four possible failure modes listed above, Accion believes that based upon our review and experience, tracking (electrical stress) was the most probable initial cause of failure.

**Evaluation for Hydro Unit Outages, Except for Outages Ayers Island 1B, Eastman Falls 2M, Jackman 1D, and Garvins 4F, 4G, and 4H**

Accion Group reviewed these outages and found them either to be reasonable and expected for these units and their vintage, or necessary for proper operation of the units. Accion Group concluded that PSNH conducted proper management oversight in the operation of these units.

**Evaluation for Ayers Island Outage 1B**

PSNH states that the procedure that is to be followed when oil is removed from the bearing reservoir is that the volume of oil removed is measured and that amount of oil is added back when the work is completed. Fluid levels are then monitored when the unit returns to service. In the instant case, PSNH states that the amount of oil measured was in error by 2½ gallons resulting in the trip of the unit due to high guide bearing oil level. Accion finds that if 2½ gallons of excess oil can overfill the reservoir, that the operator was inattentive or did not grasp the significance of the volumetric change. Accion recommends that PSNH not recover replacement power costs for the outage from customers.

**Evaluation for Eastman Falls Outage 2M**

While preparing for the annual overhaul of Unit #1, an operator switched out the marked control panel for Unit #2. Although Unit #2 did not trip and the operator rectified the situation, Unit #2 had to be taken off-line to reset the Programmable Logic Controller. Accion attributes this outage to operator inattention and recommends that replacement power costs not be recovered from customers.

**Evaluation for Jackman Outage 1D**

The overtrip of the relay at Greggs Substation associated with the A-164 115 kV terminal at Weare Substation and the F-162 115 kV terminal at Greggs Substation occurred for a single system design event. Good utility practice for the design of this condition would lead to the fact that this event should have been considered in the design of the new Weare Substation. Either PSNH did not consider this single design event or PSNH considered this design event and did not implement required changes. In either case, PSNH did not exercise due care in the design of the Weare Substation. Accion recommends that PSNH not recover replacement power costs for this outage from customers.

**Evaluation for Garvins Falls Outages 4F, 4G, and 4H**

PSNH had been having trouble in maintaining proper oil level in the lower guide bearing reservoir as reported in Outages 4C, 4D, and 4E, above, on 5/27/11, the Friday before a long holiday weekend. Over the weekend, on 5/29/11 and 5/30/11, the outages related to this problem continued as reported in Outage 4F, 4G, and 4H, above. In each of these outages, the generator restarted in 35 minutes because the pond level was such that the unit was required to generate, but PSNH did not dispatch an operator under those conditions. Accion believes that PSNH either did not fully understand the reasons for the continued unit trips and did not dispatch an operator to investigate the repetitive problem or understood the problem and let it wait until normal business hours on Monday. Accion believes that good utility practice would be to dispatch an operator in either case. Accion recommends that PSNH not recover the replacement power costs for these outages from customers.

**Recommendations**

PSNH is experiencing many overtrip conditions of its smaller units nested into the lower levels of its distribution system. Accion understands that PSNH's reliability design of its distribution system incorporates the loss of a system element with one unit out of service. If the overtrip outages are found to be systemic upon conclusion of the PSNH analysis of this issue, Accion recommends that the system reliability design incorporate the overtrips into the system design criteria on a local basis only if other economic remedies are not available.

Regarding Smith Outage 1C, PSNH is rebuilding the Berlin 115 kV bus to accommodate new generation. While that construction is undertaken, PSNH is also installing a 115 kV breaker on the Z-177 115 kV line, so that the generator is not tapped directly off the bus and exposed to bus faults that are cleared on a permissive basis. PSNH is performing similar work at Merrimack Station with regards to the two combustion turbines. Accion recommends that PSNH review all of its generation tie-in configurations, assess the risk of similar failures at those locations, and appropriately and economically address the risks found.

PSNH is experiencing more unit interruptions due to misoperations of the multitude of Mercoid switches employed across its hydro system. PSNH can no longer purchase new Mercoid switches as it has been prohibited to do so since 2008 by New Hampshire law. PSNH has identified a replacement for these switches identified as the "Reed" switch and replaces the Mercoid switches with Reed switches on a case-by-case basis. Given the legislative mercury mandate, and the identification of a suitable replacement, Accion recommends that PSNH develop a program approach with a finite time frame (to be determined) for replacement of Mercoid switches at its hydro stations and all other generating facilities.

Extreme temperatures at earlier (or later) times during the year are causing outages because ventilation fans or louvers have not been put on or have been taken off summer temperature settings. Accion recommends that PSNH review and modify the times of year it initiates changes summer temperature settings in its hydro station buildings, so that such early (or late) season events are within the summer time bandwidth, or eliminate the winter temperature period all together.

## Combustion Turbine Outages For 2011

The following outages took place at PSNH's combustion turbine units during 2011:

**Lost Nation**

Major work that was completed at Lost Nation CT-1 during 2011 included a full removal and inspection of the hot system section of the turbine.

**Lost Nation – CT-1**

A
4/26/11– 17.3 days
This scheduled 19-day outage was taken to perform the annual maintenance/inspection overhaul. The work performed included a visual inspection, general cleaning, annual equipment tests, and servicing the diesel starter engine. In addition, a full removal and inspection was performed on the hot system section of the turbine. Testing and inspections revealed no abnormalities.

B
5/13/11 – 0.2 days
At the end of the annual inspection in Outage A above, PSNH conducted the required ISO-NE black start 10-minute test. The unit passed the test and returned to service. Accion notes that PSNH separates the two events for ISO-NE recordkeeping purposes.

**White Lake**

Major work that was completed at White Lake CT-1 during 2011 included a full removal and inspection of the hot system section of the turbine.

**White Lake – CT-1**

A
2/6/11 – 0.3 days
While in reserve shutdown, the Electric-System Control Center (E-SCC) received a "Not-Ready-to-Start" alarm from the unit. Investigation found that water infiltrated the fire strobe/horn housing for the fire system causing the alarm. The fixture was replaced, a successful test startup run was performed, and the unit returned to service.

B

3/6/11 – 0.0 days

Again while in reserve shutdown, the E-SCC received a "Not-Ready-to-Start" alarm from the unit. Investigation found that water also infiltrated the electrical box that supplies power to the fire strobe/horn for the fire system, causing the alarm. The alarm was isolated and the unit returned to service. On March 24, 2011, the fire strobe/horn fixtures were upgraded with NEMA rated waterproof fixtures.

C

4/4/11 – 17.3 days

This scheduled 19-day outage was taken to perform the annual maintenance/inspection overhaul. The work performed included a visual inspection, general cleaning, and annual equipment tests. In addition a full removal and inspection was performed on the hot system section of the turbine. Testing and inspections identified several issues (anti-ice controls, deteriorated exhaust elbow packing, and the pressure differential switch for the jet engine lube oil filter cleaner that will be addressed in the 2012 maintenance outage. An ISO-NE black start test was also performed at the conclusion of the outage and the unit returned to service.

D

4/27/11 – 0.0 days

The unit was started to perform an ISO-NE claimed 10-audit test. In that test, ISO-NE calls without notice and the unit must be at 90% load within 9 minutes. While on line, a trip occurred due to the "TT7 Max/Min Spread" alarm, meaning that a 150$^{o}$F differential from the average temperature of the 6 temperature thermocouples within the engine exhaust had occurred (alarms at 100$^{o}$F). Investigation indicated that the cause was either a bad or obstructed fuel nozzle, or a bad thermocouple. A suspect thermocouple was removed from the protection scheme, which can operate on three thermocouples, and PSNH decided to schedule a future outage to determine the exact cause of the problem. The unit was returned to service. See Outage E, below.

E

5/2/11 – 0.1 days

The outage was scheduled to replace the suspect thermocouple from Outage D, above and determine the exact cause of Outage D. All thermocouples tested fine. At this time the fuel manifold was now the suspected problem and a refurbished manifold was ordered for replacement in the future. See Outage G, below.

F
5/5/11 – 0.0 days
The high-pressure air system is inspected for insurance purposes every two years. During the 2011 inspection, the inspector found that the unit start air tank, which is rated for a maximum pressure of 500 psi, had its pressure relief valve rated at 550 psi. This was clearly an improper application of the pressure relief valve. The unit was taken out of service, the unit start air tank was drained, a used 500 psi pressure relief valve was installed, and the unit was returned to service. A new 500 psi pressure relief valve was ordered for replacement in the future. See Outage G, below.

Upon investigation, PSNH states that an incorrect pressure relief valve was installed after the 2009 inspection, which required that the high-pressure relief valve be replaced due to minor air leakage. This was done in accordance with manual drawings of the start air system, which listed the pressure rating of the valve to be 550 psi. The drawings also list the air tank nameplate rating as 500 psi operation along with other air start system components. PSNH checked the station drawings and made necessary corrections to the station drawings.

G
5/21/11 – 0.5 days
The unit was taken out of service to replace the defective fuel manifold identified in Outage E, above. The new pressure relief valve for the start air tank ordered as a result of the investigation conducted in Outage F, above, was also replaced at this time.

**Schiller**

There were no major projects scheduled at Schiller CT-1 during 2011.

**Schiller - CT-1**

A
1/20/11 – 1.0 day
A phase B to ground fault occurred on the 13.8 kV feed to the coal unloader. The appropriate breaker tripped in the coal unloader 13.8 kV load center and no other operations occurred. However, during the fault, the phase B lightning arrestor failed at the original Schiller 13.8 kV switchgear room. The failure was witnessed by a station operator. The 13.8 kV coal unloader load center is fed from the 13.8 kV coal conversion load center, which was constructed with what was then new equipment for the Schiller coal conversion project in the mid-eighties. The coal conversion load center is fed from the original Schiller 13.8 kV switchgear room and all equipment in this load center was

replaced two years ago. In order to isolate the breaker at the original 13.8 kV load center for repair, an outage of CT-1 was required as that breaker also provides service to the CT. Once the breaker was isolated, the unit was returned to service with an alternate 13.8 kV feed.

PSNH did determine that the fault occurred in the flexible coal unloader arm where the electrical cables must move in tandem with the operation of the unloader arm. No cause has yet been determined for the failure of the lightning arrestor.

B
1/24/11 – 0.1 days
In preparation for an impending cold spell, PSNH wanted to roll the unit to ensure its availability during the cold weather. The unit failed to phase when requested to start in the required time allowed. PSNH found that the lube oil was too thick resulting in a slower turn speed during start-up that resulted in the time out. The oil pump was operated for a few hours and the unit started successfully.

PSNH believes that the air pressure issue identified in Outage C, below, may have contributed to the failed start. Procedures have been changed to leave the oil pump in service during periods of extreme cold to ensure that the oil is warm.

C
4/22/11 – 0.0 days
The unit failed to start when requested, due to a timing sequence failure. The unit started on the second attempt; however, it missed its required ISO-NE 10-minute window and had to be declared out of service. It was suspected the problem related to the start air controls. An adjustment was made to those controls after the successful start and the unit has operated properly since that time. In addition, an air pack was installed to improve the capabilities of the start air system.

D
5/16/11 – 4.3 days
This scheduled 5-day outage was taken to perform the annual inspection. The work performed included a visual inspection, general cleaning, and annual equipment tests. Testing and inspections revealed no abnormalities.

E

12/8/11 – 0.0 days

The unit was taken out of service so that the transformers in the control building could be safely tested for PCB contamination. The tests were performed and the unit returned to service. The tests were negative, so no further outages for this purpose will be required.

**Merrimack**

Major work that was completed at Merrimack combustion turbines in 2011 included the installation of a high side 115 kV breaker for the common MT-3 step-up transformer which serves both CTs.

**Merrimack CT-1**

A

4/14/11 – 7.6 days

This scheduled 5-day outage was taken to perform the annual inspection in conjunction with unit CT-2 as they share a common step-up transformer. The work performed included a visual inspection, general cleaning, and annual equipment tests. Testing and inspections revealed no abnormalities. The annual inspection was coordinated to take place during the transmission yard work required for the Clean Air Project, which extended the duration of the outage. See Outage CT-2B, below.

B

7/22/11 – 4.3 days

The unit failed to start when requested. The problem was traced to the fuel system module fuel controller card. PSNH maintains two vendors to do combustion maintenance work rather than incorporating expensive on-call requirements into the contracts. PSNH requested both vendors troubleshoot the card but had difficulties obtaining either vendor over the weekend because of other service calls or projects. One of the vendors arrived on-site on Tuesday July 26, 2011, calibrated, and tested the card. The test results were okay and the unit returned to service.

C

8/3/11 – 0.1 days

While making a routine operator inspection round, the operator discovered a location that was dripping fuel. A slightly pinched O ring was found between the solenoid valve and the fuel control valve, replaced, and the unit returned to service. PSNH suspects that the damage most likely occurred during the installation during the spring annual inspection outage. Repairs were made and the unit returned to service.

D
9/6/11 – 0.0 days
The unit's fire protection system is tested annually by a contractor. A fire control solenoid was found to be faulty. The unit was taken out of service as the fire control solenoid must be in service for the unit to start, as it is part of the permissive start procedure. The faulty solenoid was replaced and the unit returned to service.

E
9/8/11 – 14.5 days
At Merrimack Station, Unit 1 and the two combustion turbines connect to the #1 115 kV bus. Unit #1 has the ability to be isolated from the #1 bus, but the combustion turbines do not. An outage of Unit 1 is, therefore, required to address issues with the combustion turbines. This outage was planned to install a 115 kV breaker on the high side of MT-3, the common step-up transformer for the two CTs. With this breaker installed, the reliability of Unit 1 is increased. This outage was taken to install a new high side disconnect switch, make preparations for the installation of the new MT-3 breaker, and to install a strain bus that would allow for operation of the CTs after MK-1 returned to service. This outage was coordinated to take place during other 115 kV transmission work at the station.

F
10/3/11 – 4.6 days
During Outage E, above, a temporary strain 115 kV bus was installed to facilitate operation of the unit. This outage was scheduled to remove the temporary facilities and testing of MT3. The temporary facilities were removed, MT3 testing was performed, and the unit returned to service.

G
10/19/11 – 0.3 days
PSNH's electrical contractor, Eaton Electric, did a coordination study and found that the main 13.8 kV breaker for the CT was over its interrupting capability and that it did not meet arc flash standards. PSNH discussed the possibilities as to the cause of the over duty condition and determined that the likely cause dated back to the installation of CT-2 in 1968.

CT-1 was installed in 1967 and has a main 13.8 kV breaker that was sized to handle available fault duty existing at that time. It appears that when CT-2 was installed in 1968, that its main 13.8 kV breaker was sized the same as the CT-1 breaker. With two combustion turbines installed, both breakers were under rated. This condition was not identified until studies were performed relating to the installation of the new MT-3 high side breaker. Regardless of the 13.8 kV breaker rating, replacement at this time was required to meet the new arc flash standards.

H
12/20/11 – 0.0 DAYS
The unit failed to start when requested. Investigation found that the fuel control valve was acting sluggishly. The valve was cycled a few times and the unit successfully started.

**Merrimack CT-2**

A
3/30/11 – 0.0 days
One of PSNH's combustion turbine service contractors is new. That contractor needed the unit to be taken out of service so that the dimensions for the jet engine inlet air filter could be determined and fabricated for the upcoming annual maintenance overhaul. The dimensions were not on the manufacturer's drawings. The dimensions were determined and the unit returned to service.

These inlet filters are not changed often. The last time the filters were changed was approximately ten years ago and PSNH did not have records that indicated the exact filter dimensions. PSNH contacted Pratt & Whitney regarding the dimensions of these filters and Pratt & Whitney could not confirm filter measurements due to the multiple filter designs used for this vintage unit.

B
4/14/11 – 8.2 days
This scheduled 5-day outage was taken to perform the annual inspection in conjunction with unit CT-2 (common step-up transformer) during the scheduled transmission high yard outage. The work performed included a visual inspection, general cleaning, and annual equipment tests. Testing and inspections revealed no abnormalities. See Outage CT-1A, above.

C

5/5/11 – 0.2 days

When the annual maintenance overhaul was performed in Outage B, above, an insufficient number of jet engine inlet air filters were fabricated and available for replacement. This outage was required to replace those air filters that were not replaced during the annual maintenance overhaul.

In Outage CT-2A, above, the contactor confirmed the dimensions of the inlet filters and made a count of the number of assemblies required. Approximately 100 inlet filter assemblies exist in this unit and it appears that the contractor mis-counted the number of filter assemblies required. The remaining filters were installed during this outage at no labor cost to PSNH.

D

7/22/11 – 5.0 days

The unit started but would not control voltage in the automatic mode. PSNH took the unit off line, put the voltage regulator in manual control, and started the unit. Once running, voltage control was switched to automatic. This voltage regulator is near the end of its useful life. A replacement has been in stock since early 2011 pending previous application to ISO-NE for approval to replace the regulator.

The CT-2 generator voltage regulator is identical to that in CT-1 and it also needs replacement. PSNH had previously determined that the generator voltage regulator for CT-2 was in worse condition than CT-1 and would be replaced first. The generator voltage regulator for CT-2 was received in early 2011 and as of the end of 2011; PSNH is still awaiting approval from the ISO-NE to install the equipment.

PSNH states that it received approval from ISO-NE in 2012 to also include the CT-1 voltage regulator in the approval for the installation of the CT-2 voltage regulator. The scope of the studies has been approved and studies are to be performed in the fall of 2012 with approval to follow. Once approval is obtained from the ISO-NE, PSNH will install the CT-2 voltage regulator and procure and install the CT-1 voltage regulator.

E

9/8/11 – 14.5 days

Please see Outage CT-1E, above

F

10/3/11 – 4.6 days

Please see Outage CT-1F, above.

G
10/19/11 – 0.3 days
Please see Outage CT-1G, above.

H
12/20/11 – 0.2 days
When requested to start, the unit would not properly ramp up to speed. Investigation found that a fuel control valve actuator failed, preventing the unit from attaining desired speed. The actuator was replaced and the unit returned to service.

**Evaluation for Combustion Turbine Outages**

Accion Group reviewed the outages, above, and found them either to be reasonable and not unexpected for these units and their vintage, or necessary for proper operation of the unit. Accion Group concluded that PSNH conducted proper management oversight during these outages.

**Recommendations**

Regarding Outage White Lake 1F, above, Accion recommends that PSNH place a “hold” on work and question the replacement when an engineer, operator, or mechanic is replacing equipment that is not “in kind” until the replacement is well understood. This recommendation would fit well with a training program that trains the employee to have a questioning attitude.

Problems with the installations of gaskets and other interface mediums such as the O ring in Outage Merrimack CT-1C, above, and the hydrogen coolers at Schiller Station have become problematic in both 2010 and 2011. In 2010, Accion recommend that PSNH set up a system where installers of gasket materials bring issues to management’s attention during the outage to prevent down time once back in service. Accion believes that PSNH needs to both review the changes in compatibility of materials used in interface connections and strengthen its training of proper installation of the various interface sealing mechanisms and recommends that it do so at all of its stations, including hydro operations.

## W. F. Wyman 4 Outages For 2011

### W. F. Wyman Station

The W. F. Wyman Station was sold in the 1990's to a competitive power supplier and competes in the New England competitive market to sell its power. PSNH is a minority owner (approximately 3%) of Unit #4 at the station. Nextera Energy Resources (Nextera) owns the majority of the unit and is responsible for day-to-day operations. As a minority owner, PSNH is aware of how the plant conducts business. However, PSNH has little influence over day-to-day operations of the plant. Accion Group makes this distinction because it believes the extent of outside ownership makes the measurement of prudence different than the measurement used for PSNH's wholly-owned and controlled units providing energy at cost to PSNH customers. This unit is a high cost oil unit operating under tight environmental restrictions and at an annual capacity factor of less than 5%.

The major projects performed at Wyman 4 in 2011 were the replacement of both the A and B preheater baskets and seals in addition to the complete boiler inspection performed during the annual overhaul in Outage G, below.

**W. F. Wyman 4**

A
1/22/11– 0.0 days
The unit was requested for a 6 AM start by ISO-NE, but experienced a delayed phase until 7 AM. During start-up, the 4A gas recirculation fan would not engage. Investigation found that the mechanical linkage that makes electrical contact to close the 4A recirculation fan breaker was broken. Repairs were made and the unit returned to service.

B
3/29/11 – 4.1 days
In 2011, W. F. Wyman 4 was in the process of changing its annual maintenance outage position from spring to fall. The unit has a State of Maine boiler operation certificate that is only valid for 12 months and which expired in spring 2011, coinciding with the existing maintenance schedule. In order to change the outage schedule, the unit needed to be taken out of service to have a boiler inspection performed so that a new valid certificate could be issued. The boiler inspection was completed and the unit returned to service.

C

5/13/11 – 14.9 days

The unit was taken out of service by ISO-NE to accommodate a transmission outage request by Central Maine Power for reliability upgrades in the area. Because the work was transmission related, no further information was given to the plant owners. See Outage D, below.

D

7/16/11 – 1.3 days

The unit was taken out of service by ISO-NE to accommodate a transmission outage request by Central Maine Power for reliability upgrades in the area. Because the work was transmission related, no further information was given to the plant owners. See Outage F, below.

E

7/21/11 – 0.0 days

The unit tripped on loss of generator stator temperature. Investigation found that a fuse had blown in the transducer that transmits the generator stator coolant temperature, which caused the loss of the generator stator temperature signal, as coolant temperature is an input to the stator temperature calculation. The fuse was replaced and the unit returned to service.

F

9/9/11 – 0.1 days

The unit was in reserve shutdown when two 115 kV and one 34.5 kV lines were simultaneously lost causing a complete power outage to the station. The plant inquired as to the cause from Central Maine Power Company, but the company would not give the plant any information.

G

9/17/11 – 29.4 days

The outage was taken to perform the annual overhaul of the unit. The outage had an ISO-NE window of 30 days and was internally scheduled for completion in 30 days. The critical path throughout the outage was the work associated with the replacement of the A and B preheater baskets and seals. Other major work during the outage was a complete inspection of the boiler. The work was completed on schedule.

**Evaluation**

Accion Group reviewed the above outages and found them either to be reasonable and not unexpected for this unit and its vintage, or necessary for proper operation of the unit. Accion Group concluded that PSNH conducted proper management oversight.

**Open Stipulation Items from Prior Years**

**Stipulation Items from the 2008, 2009, and 2010 Energy Service/Stranded Cost Recovery Review**

**(Docket DE 09-091 Labeled as 2009-XX), the 2009 Energy Service/Stranded Cost Recovery Review (Docket DE 10-121 Labeled as 2010-XX), and the 2011 Energy Service/Stranded Cost Recovery Review (Docket DE 11-094 Labeled as 2011-XX)**

During the 2008 Energy Service/Stranded Cost Recovery Charge reconciliation (ES/SCRC) conducted in 2009 in Docket DE 09-091, PSNH and the parties stipulated to a number of items to resolve outstanding issues in the case (2009 Stipulation). The 2009 Stipulation was filed on November 20, 2009 and approved in Order No. 25,060 (December 31, 2009). The stipulated items were reviewed in 2010 as part of the 2009 ES/SCRC reconciliation in Docket DE 10-121. The 2010 Stipulation was filed on January 11, 2011 and approved in Order No. 25,216 (April 29, 2011). The stipulated items were reviewed in 2011 as part of the 2010 ES/SCRC reconciliation in Docket DE 11-094. Many items were closed at that time. Accion Group, Inc. ("Accion Group" or "Accion") reviewed the actions taken by PSNH on each remaining 2008, 2009, and 2010 open stipulated items from the ES/SCRC reviews in Docket DE 09-091, Docket DE 10-121, and Docket DE 11-094. Accion's comments follow.

**2009-1 – Mitigation of Customer Costs Regarding Certain 2008 Generation Unit Outages**

PSNH presented an accounting of all replacement power costs related to the 2008 Merrimack Turbine outage. In the initial claim, PSNH put in a property claim of $21.0 million, replacement power cost of $13.9 million. The replacement cost claim resulted in a mutually agreed upon amount of $12.5 million and the $21.0 million claim was reduced by its deductible of $1.0 million. PSNH customers received $32.5 million and credited that amount to customers. As noted below in Item 2010-1, PSNH is also pursuing reimbursement of the $1.0 million property damage deductible. This information is detailed in the PSNH response to STAFF-01, Q-STAFF-005 in Docket No. DE 12-116.

**Recommendation**

Staff is satisfied with PSNH's accounting in this matter and advises Accion that it recommends the item be closed.

**2009-2 – Schiller Warranty Items**

PSNH booked the final two Schiller warranty settlement amounts of $750,000 each in January and June of 2011. Of these credits, $1.0 million was booked capital accounts and $500,000 was booked to O&M. This information is detailed in the PSNH response to TECH-01, Q-TECH-001 in Docket No. DE 12-116.

**Recommendation**

Staff is satisfied with PSNH's accounting in this matter and advises Accion that it recommends the item be closed.

**2009-5 - Interconnection of PSNH Generating Units to the PSNH Distribution System**

In Section III-D of the 2009 Stipulation, PSNH agreed to perform an interconnection analysis of all its units connected to its lower voltage distribution system. Over the years, many incorrect unit trips occurred as a result of unrelated system outages. This analysis is an effort to determine if protection coordination is part of the problem. PSNH additionally committed to file a report on its progress on this matter along with an estimated completion schedule with the Commission in the 2009 ES/SCRC review (Docket DE 10-121).

PSNH filed a progress report with the Commission on May 7, 2010. The studies were reviewed as part of the 2009 ES/SCRC review in Docket DE 10-121. At that time, only the undervoltage studies had been completed and implemented. The remaining studies remained open. PSNH agreed to report on this issue as part of its filing for the 2010 ES/SCRC review on May 1, 2011 (DE 10-121 Stipulation [2010 Stipulation] Section III.E.5).

In its May 1, 2011 filing in Docket DE 11-094 for review of the 2010 ES/SCRC, PSNH reported that overvoltage relay studies were complete and settings were implemented in the field. PSNH also reported that relay testing was complete, and that a comprehensive relay testing program was in place. The remaining studies remained open.

During its analysis, PSNH found issues relating to protection coordination in the areas near the hydro units. However, solutions were not identified and implemented until late 2010, so inadvertent trips still appeared in quantity in the 2010 ES/SCRC review conducted during 2011. PSNH stated that the coordination review would be completed in 2011. PSNH agreed to report on this issue as part of its filing for the 2011 ES/SCRC review in May 2012 (DE 11-094 Stipulation [2011 Stipulation] Section IV.E).

PSNH filed a progress report with the Commission on May 2, 2012 as part of its 2011 ES/SCRC review. The progress report was attached to the testimony of William H. Smagula at Appendix A, Recommendation 5. Prior to continuing with the coordination studies at the hydro stations, PSNH needs to obtain the ability to analyze its distribution power system from a transient stability viewpoint. That item became a separate action item apart from the coordination studies and is discussed in Item 2011-6 below.

**Recommendation**

Accion recommends that this item remain open while transient stability analyses are completed and incorporated into the overall coordination analysis.

**2010-1 - Tracking Insurance payments from the 2008 MK-2 Turbine Outage**

From Section III-B of the 2009 Stipulation, PSNH agreed to provide a showing of its efforts to mitigate customer costs related to certain 2008 generating unit outages: Outage MK-2 E, Outage NEW 1-C, and Outage NEW 1-D. Only the Outage of MK-2E remained open to capture the final settlement of insurance reimbursement. PSNH agreed to report on this issue as part of its filing for the 2010 SCRC review on May 1, 2011 (DE 10-121 Stipulation, Item III.E.1). PSNH reported on this issue as part of its May 2011 filing for the 2010 SCRC review. Where replacement power costs were settled in Docket DE 11-094, the Commission assigned a new stipulation number (2010-1) for tracking the machinery insurance deductible recovery payments from the lawsuit (DE 11-094 Stipulation, Item III.E) and required PSNH to report on progress as part of its May 1, 2012 filing for the 2011 ES/SCRC review (Docket DE 11-094). PSNH reported on this issue in its May 2, 2012 filing in Appendix A of the testimony of William H. Smagula as Recommendation No. 7.

According to PSNH, its insurance carrier performed an independent analysis regarding the root cause of the foreign material that damaged the MK-2 turbine. The insurance carrier believes it has sufficient documentation to show that Babcock & Wilcox (B&W) was the source of the foreign material and has initiated legal action against B&W to try to recoup its loss. PSNH stated that it has joined in the insurance carrier’s suit. If recovery is made, PSNH would receive the first $1,000,000 of recovery representing its deductible for its boiler and machinery claims policy. Any recovery made by PSNH would be credited to customers. PSNH states that the legal action is in the discovery stage and a conclusion date is undetermined at this time.

**Recommendation**

Where litigation relating to this issue is still ongoing, Accion recommends that this issue remain open and that PSNH file an update of its progress as part of its 2012 ES/SCRC filing in May 2013.

## Stipulation Items from the 2010 ES/SCRC Review in Docket DE 11-094

During the 2010 ES/SCRC review conducted in 2011 in Docket DE 11-094, PSNH and the parties stipulated to a number of items to resolve outstanding issues in the case (2011 Stipulation). The 2011 Stipulation was filed on November 22, 2011 and approved in Order No. 25,321 (January 26, 2012). The stipulated items were reviewed in 2012 as part of the 2011 ES/SCRC reconciliation in Docket DE 12-116.

### 2011-1 – Preparing Units for Longer than Previous Normal Shut Down Times

In the 2011 Stipulation, PSNH agreed to review start-up procedures for all its major units (Merrimack, Schiller, and Newington) to determine if changes needed to be made to start-up (or shut-down) procedures when coming on line after longer than normal downtimes (2011 Stipulation, Section IV.D.1).

PSNH reported on this item in its May 2, 2012 filing (See the testimony of William H. Smagula, Appendix A, Recommendation 1). PSNH states that the management teams of Merrimack and Schiller Stations discussed this issue with the management team of Newington Station who has been addressing this issue for the past two years, the equipment manufacturers, and PSNH's Generation Maintenance rotating equipment specialists. While the changes in procedures may vary from station to station because of fuel, capacity factor, etc., PSNH used the Newington procedures and findings as a starting point and then adapted the logic specifically to the other stations. The primary focus of PSNH's assessment was to use a more proactive approach to confirm that critical equipment is in a ready-to-run state and functional when a unit is called for in the dispatch with minimal adjustments to existing ISO-NE start-up times.

A short summary of PSNH's procedure changes that have been made to date follows:

#### Merrimack Station

**Turbine** – Keep the rotor on turning gear, keep the turbine oil system in service, install a temporary heating source to the exciter, and cycle the turbine throttle valves.

**Bulk Material Handling Systems** – Routinely run system belts of the clean coal, limestone, and gypsum feed systems of the units and scrubber to avoid hardening or agglomeration. Prepare bunkers for extended layup by managing the level of coal (running them down on shutdown).

**Scrubber** – Rotate ball mills, ensure motor heaters are in service, routinely operate mill pumps, and manage the limestone silo level.

**Boiler** – PSNH currently lays up its boilers at Merrimack with the "dry" method where the boilers are drained and inert gas is added to prevent corrosion. A boiler may also be layed up with the "wet" method where the boiler is not drained and chemicals are added to prevent corrosion. PSNH is currently analyzing the pros and cons of each method.

**Schiller Station**

**Turbine** - Keep the turbine oil system in service, install a temporary heating source to the exciter, and cycle the turbine throttle valves.

**Bulk Material Handling Systems** – Routinely run fuel system belts. Prepare bunkers for extended layup by managing the level of coal (running them down on shutdown) and clean coal feed system to reduce the chance of pluggage.

**Boiler** – Because the boilers at Schiller are different than at other stations, auxiliary steam is required for the oil tank farm temperature so the boilers are left full and under auxiliary steam pressure. Units #4, #5, and #6 have a common auxiliary steam system which can be kept pressurized by any unit. The boiler can also be kept pressurized by the wood unit if the coal units are in reserve shutdown or by oil if all units are out of service.

PSNH states that it continues to explore this issue looking forward.

**Recommendation**

Accion believes that PSNH has adequately addressed the concern presented in Docket DE 11-094. In addition, conversations with PSNH indicate that they have full knowledge of the topic and understand what changes need to be made to procedures if the situation reverses and the units are called upon to supply more energy to the market place. Accion recommends closure of this item.

**2011-2 – Addressing Potential Gasket Problems within the Confines of the Existing Outage**

In the 2011 Stipulation, PSNH agreed that when any contractor or company personnel suspects that gasket installations are problematic, PSNH management should be notified of such problems to evaluate the need for rework at that time within the confines of the existing outage schedule rather than potentially impede the maintenance schedule at the conclusion of the outage. This issue was to be addressed at all plants (2011 Stipulation, Section IV.D.2).

PSNH responded to this item in its filing on May 2, 2012 in the testimony of William H. Smagula, Appendix A, Recommendation 2. PSNH states that its current practices reinforce the importance of quality work and that during any outage PSNH assigns a liaison to oversee the work and to facilitate communication between the contractor and station management on safety, work quality, and productivity.

PSNH states that in an effort to reinforce the importance of quality workmanship and proper communication, it has instituted specific actions to discuss this issue with contractors at pre-planning outage meetings and to discuss these issues at the daily outage meetings during the outage. This practice has been implemented at all plants and hydro as appropriate.

**Recommendation**

Accion believes that the PSNH action addresses the concern put forth in its recommendation during Docket DE 11-094 and recommends that this item be closed.

Accion also notes that there are issues with gasket installation and addresses those issues in other another module of its review.

**2011-3 – Vegetation Outages along the 355 and 355X10 34.5 kV Circuits**

In the 2011 Stipulation, PSNH agreed to conduct a vegetation inspection of the 355 and 355X10 34.5 kV circuits that are connected to the Canaan Hydro Station. Multiple outages had occurred due to vegetation contact. Accion had further recommended that recovery of the replacement power costs for Outages Canaan 1C, 1D, 1E, 1F, 1G, 1K, and 1M be deferred until this issue was reviewed in the 2011 ES/SCRC review, the instant docket DE 12-116 (2011 Stipulation, Section IV.D.3).

PSNH responded to this item in its filing on May 2, 2012 in the testimony of William H. Smagula, Appendix A, Recommendation 3.

> **355 34.5 kV Line**
>
> Outages 1C, 1D, and 1E were directly a result of vegetation events. Outage 1F could not be confirmed as a tree related outage, but is suspected that the cause was a tree. PSNH states that its vegetation management practices include removal of hazard trees for circuits in rights-of-way. In phase one of the Reliability Enhancement Program (REP)/Vegetation Management Program (VMP), PSNH reduced the trim cycle for rights-of-way to five years and increased hazard tree removal. In addition, and beginning on July, 1, 2010, PSNH introduced phase 2 into the REP/VMP which included the reclamation of rights-of-way to full width. With respect to the subject outages, PSNH identified most of the trees causing the outages as being from outside of the trim zone. PSNH's inspection in 2010 identified 36 hazard trees in the right-of-way. Trees that posed an imminent danger of causing an outage were immediately removed and the remaining danger trees were scheduled for removal.

Scheduled right-of-way maintenance was to take place in 2012. PSNH deferred this maintenance trimming to 2013 but also scheduled another vegetation management patrol in late 2012 to pick up additional vegetation problems so they could all be addressed at that time.

**355X10 34.5 kV Distribution Circuit**

PSNH identified Outages 1G, 1K, and 1M as tree related events, mostly from outside of the trim zone. PSNH states that its vegetation management practices include scheduled tree trimming, enhanced tree trimming, maintenance enhanced tree trimming, mid-cycle tree trimming, and hazard tree removal. PSNH states that regularly scheduled tree trimming for this circuit is scheduled for 2012.

Accion notes that no specifics were supplied by PSNH pertaining to what parts of its vegetation management programs were applied to this distribution circuit nor were a number of danger trees found. Accion believes that less extensive record keeping practices is the cause for the lack of information.

**Recommendation**

Accion refers the reader to 2011 Stipulation Item 2011-4 discussed directly below as it is similar to the instant issue and Accion presents its overall recommendation for Item #3 and Item #4 there.

**2011-4 – Vegetation Outages along the 335/332 34.5 kV Circuits**

In the 2011 Stipulation, PSNH agreed to conduct a vegetation inspection of the 335/332 34.5 kV circuits that are connected to the Hooksett and Garvins Hydro Stations. Multiple outages had occurred due to vegetation. Accion had further recommended that recovery of the replacement power costs for Outages Hooksett 1A, 1B, and 1C plus Garvins Outage M-A be deferred until this issue was reviewed in the 2011 ES/SCRC review, the instant docket DE 12-116 (Stipulation, Section IV.D.4).

PSNH responded to this item in its filing on May 2, 2012 in the testimony of William H. Smagula, Appendix A, Recommendation 4. PSNH identified these outages as tree related events with most of the trees located outside of the right-of-way. PSNH states that it conducted a patrol in late 2011 for this line consistent with current vegetation management practices and found 22 danger trees within the right-of-way.

Accion notes that normal vegetation management practices generally do not address vegetation issues that are outside of the right-of-way.

**Recommendation**

Tree related outages are numerous and, in many instances, caused by trees that are outside of the maintained right-of-way. PSNH has obtained rights as part of its easements to remove trees that are out of the right-of-way if they pose a danger to operation of the power system for most of its transmission lines and an unknown amount of its 34.5 kV lines. These trees are identified as danger trees could cause the following operational problems:

- Potential interruption of service to PSNH generation
- Potential interruption to the multitude of market generators connected to the PSNH system (most bought by PSNH)
- Potential interruption to customers during severe weather events.

PSNH addresses what they call hazard trees (danger trees within the right-of-way) during the vegetation management process but generally does not address danger trees outside of the right-of-way even though in many cases it has the easement rights to do so. PSNH is aware of the operational danger to the transmission and distribution (T & D) system from trees outside of the right-of-way. The Northeast Utilities (NU) transmission vegetation management budget for 2013 proposes (not yet approved) to spend $800,000 on danger trees that are outside the right-of-way and the distribution vegetation management program has begun to identify easements which allow PSNH to address danger trees outside of the right-of-way.

Accion recommends that PSNH initiate a five-year program that continuously addresses danger trees that are outside of the right-of-way as part of its regular vegetation T&D maintenance cycles. As Accion understands the jurisdictional differences, the cost of addressing danger trees on the transmission system would flow through transmission charges, while PSNH would be responsible for funding the program on the distribution side.

Accion further recommends that the cost associated with the outages discussed in Item 2011-3 and Item 2011-4 not be recovered from customers.

**2011-5 – Planning for Emergent Issues at Small Hydro Stations**

In the 2011 Stipulation, PSNH agreed to focus its non-destructive examinations (NDE) on major hydro components (runners, draft tubes, etc.) and develop a comprehensive plan to address the results of the NDE examinations. Specifically, it was expected that items such as exciters, runners, step-up transformers, rotors, stators, and draft tubes be explicitly addressed (2011 Stipulation, Section IV.D.5).

PSNH responded to this item in its filing on May 2, 2012 in the testimony of William H. Smagula, Appendix A, Recommendation 6. PSNH stated that it has created a Project Plan that incorporates NDE examinations of the equipment specifically mentioned into its maintenance planning process with the intention of creating a comprehensive NDE plan. PSNH has completed an assessment of the equipment that is listed above and has identified the proper NDE practices based on industry standards for each piece of equipment. PSNH is reviewing the appropriate NDE schedule for each piece of equipment, determining proper schedule placement that aligns with unit overhaul schedules, and will incorporate its findings into the unit maintenance schedules.

**Recommendation**

PSNH has implemented an ongoing process which directly addresses the concerns set forth in Docket DE 11-094. Accion recommends that this issue be closed.

**2011-6 – PSNH In-House Transient Stability Analysis (Unresolved Issue)**

In the 2011 Stipulation, Accion recommended with the support of Staff that PSNH obtain the in-house ability to perform transient stability analysis to aid the resolution of inadvertent generator overtrips caused by faults on the distribution system, and to aid in the determination of proper time delays of undervoltage relays to maintain stability for properly cleared faults (2011 Stipulation, Section IV.G).

The issue was presented to the Commission at the hearing on the merits held on November 29, 2011. At the hearing, PSNH requested that it be given time to review the resource requirements of acquiring the ability to perform the studies and the resource requirements to perform the analyses. In its order in Docket DE 11-094, the Commission granted the ability to address this issue in a post hearing forum (Order No. 25,321 dated January 26, 2012, P17-P18).

Post hearing, on December 8, 2011, PSNH and Accion participated in a conference call on this subject. During that conference call, PSNH agreed to acquire the capability to perform in-house transient stability analyses. PSNH responded to this item in its filing on May 2, 2012 in the testimony of William H. Smagula, Appendix A, Recommendation 5. PSNH informed Staff that it could utilize the in-house transient stability program currently used by its transmission engineers for such purposes. Transmission planners use the Power System Simulator for Engineers (PSS/E) software that is supported by Siemens Power Technologies Inc. This program is considered as state-of-the-art by the power industry.

PSNH is in the process of training in-house personnel. PSNH is sending technical personnel to attend courses at the Siemens Power Academy TD in Schenectady, NY. Topics studied include modeling and building tools, data development and software operation, and analysis and mitigation of power system voltage and stability problems. PSNH is currently gathering data to construct models to analyze the Canaan and Jackman hydro areas. Accion agrees that these two areas are the highest priority for analysis.

**Recommendation**

Where analyses are not complete, Accion recommends that this issue remain open and further recommends that PSNH file an update of its progress as part of its 2012 ES/SCRC filing in May 2013.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-001**
**Page 1 of 2**

**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Baumann testimony, Attachment RAB-2. Please provide a schedule in the same format as the response to STAFF-01, Q-STAFF-029 in DE 11-094 detailing the calculation of replacement power costs. Please specifically detail any changes in the calculation method as compared to prior years

**Response:**
Please see the attached table for the requested information.

There were no differences in calculation methodology as compared to previous submittals.

The replacement power costs were calculated hourly. For each hour, all supply resources (owned units, IPPs, bilateral purchases and ISO-NE spot purchases) were ordered based on their estimated dispatch prices from lowest cost to highest cost. The hour's actual energy expense was estimated by adding up the expenses of the resources whose output added up to the load. In a subsequent analysis, the unit out of service was placed back into the supply stack at an assumed availability and at the appropriate place in the dispatch order. The hour's energy expense was then recalculated as if the unit had been available. The replacement power cost was the difference in the cost to serve load between the two analyses.

The attached table summarizes by day the replacement power cost for each outage reported in RAB-2. The table lists each day's total replacement power costs, replacement power costs attributable to ISO-NE spot market purchases, replacement power costs attributable to bilateral purchases, replacement power costs attributable to PSNH generation and the avoided fuel expense attributable to the unit out of service.

**Merrimack 1**

| Date | Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|---|
| 01/04/2011 | 10,152 | 27,736 | 0 | 671 | (18,256) |
| 01/05/2011 | 32,132 | 5,646 | 11,205 | 21,915 | (6,633) |
| 01/06/2011 | 32,796 | 56,261 | 0 | 6,352 | (29,817) |
| 01/07/2011 | 29,321 | 4,152 | 0 | 25,711 | (541) |
| Total | 104,401 | 93,794 | 11,205 | 54,649 | (55,246) |

**Merrimack 2**

| Date | Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|---|
| 01/25/2011 | 182,821 | 222,060 | 0 | 13,048 | (52,287) |
| 01/26/2011 | 292,053 | 77,331 | 193,743 | 47,743 | (26,764) |
| 01/27/2011 | 252,201 | 118,101 | 336,919 | 0 | (202,819) |
| 01/28/2011 | 292,170 | 126,406 | 297,467 | 13,662 | (145,366) |
| 01/29/2011 | 163,120 | 41,545 | 0 | 121,575 | 0 |
| Total | 1,182,364 | 585,443 | 828,129 | 196,028 | (427,236) |
| | | | | | |
| 03/05/2011 | 42,811 | 235,072 | 0 | 0 | (192,261) |
| 03/06/2011 | 34,361 | 258,980 | 0 | 0 | (224,619) |
| 03/07/2011 | 120,423 | 328,286 | 0 | 0 | (207,863) |
| Total | 197,595 | 822,338 | 0 | 0 | (624,742) |
| | | | | | |
| 05/13/2011 | 6,329 | 24,794 | 0 | 449 | (18,915) |
| 05/14/2011 | 56,783 | 212,938 | 0 | 0 | (156,155) |
| 05/15/2011 | 36,784 | 219,007 | 0 | 0 | (182,224) |
| 05/16/2011 | 223 | 2,790 | 0 | 0 | (2,568) |
| Total | 100,118 | 459,530 | 0 | 449 | (359,861) |
| | | | | | |
| 12/07/2011 | 0 | 0 | 0 | 0 | 0 |
| 12/08/2011 | 0 | 0 | 0 | 0 | 0 |
| 12/09/2011 | 0 | 0 | 0 | 0 | 0 |
| 12/10/2011 | 0 | 0 | 0 | 0 | 0 |
| 12/11/2011 | 0 | 0 | 0 | 0 | 0 |
| 12/12/2011 | 0 | 0 | 0 | 0 | 0 |
| Total | 0 | 0 | 0 | 0 | 0 |

**Newington**

| Date | Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|---|
| 09/21/2011 | 0 | 0 | 0 | 0 | 0 |
| 09/22/2011 | 0 | 0 | 0 | 0 | 0 |
| 09/23/2011 | 0 | 0 | 0 | 0 | 0 |
| Total | 0 | 0 | 0 | 0 | 0 |

**Schiller 5**

| Date | Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|---|
| 11/12/2011 | 205 | 4,797 | 0 | 0 | (4,592) |
| 11/13/2011 | 1,378 | 32,179 | 0 | 0 | (30,802) |
| 11/14/2011 | 5,921 | 29,508 | 0 | 966 | (24,554) |
| 11/15/2011 | 7,458 | 7,994 | 0 | 5,206 | (5,742) |
| 11/16/2011 | 10,235 | 7,265 | 0 | 8,960 | (5,990) |
| 11/17/2011 | 12,068 | 6,449 | 0 | 9,570 | (3,950) |
| 11/18/2011 | 11,732 | 21,702 | 0 | 3,820 | (13,789) |
| 11/19/2011 | 2,897 | 4,728 | 0 | 1,959 | (3,791) |
| Total | 51,894 | 114,622 | 0 | 30,481 | (93,209) |

**Total All Units 2011**

| Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|
| **1,636,373** | **2,075,727** | **839,334** | **281,607** | **(1,560,295)** |

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-005**
**Page 1 of 1**

**Witness:** **Robert A. Baumann, William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Baumann testimony, Attachment RAB-4, page 8, footnote (2). Regarding the $4.418M credit for Merrimack insurance proceeds, please provide an updated status of the issue of insurance proceeds related to the turbine repair and outage. Please also include a discussion of the status of the efforts to recover the insurance deductible.

## Response:

As reported earlier, PSNH submitted the insurance claim for the property damage and the replacement power associated with the foreign material damage to the Merrimack Unit 2 turbine incident. The net claim amount was $33.9M as shown below.

| | ($M) |
|---|---|
| Property damage portion | $21.0 |
| Replacement power claim | $13.9 |
| Total Claim | $34.9 |
| Less deductible | $1.0 |
| Net Claim | $33.9 |

To date, with the receipt of the $4.418 million of replacement power costs as noted in Attachment RAB-4, page 8, PSNH and its customers have received $32.5 million. The property damage claim has been fully reimbursed except for the $1 million deductible. Discussions with the insurance companies, their consultants, as well as Northeast Utilities (NU) Insurance and Claims Department and Generation management had taken place in September and October of 2011 in order to respond to insurers' detailed review and resulting questions in an effort to bring final resolution to this claim. During those discussions, insurance representatives raised questions regarding assumptions and calculations associated with the replacement power claim and based on their review of all the information exchanged and discussions held, the insurers put forth counter reimbursement proposals. After lengthy discussions and negotiations, a settlement amount of $12.5 million for the replacement power claim was reached among all involved. This settlement amount was deemed appropriate by NU personnel in the Insurance and Claims Department, Treasury, as well as PSNH Generation. This settlement results in a final total reimbursement to PSNH and its customers of $32.5 million.

The insurers have now brought action as subrogees of Northeast Utilities to the extent of those payments. In this subrogation action, the insurers have alleged that during the installation of the new HP-IP turbine, Babcock & Wilcox supplied secondary superheater inlet pendant tubes which were contaminated with foreign object debris. The insurers allege that, during startup of the steam turbine, the foreign object debris damaged the turbine and other components in the system. If successful, this subrogation action could result in an additional reimbursement to PSNH customers for the deductible paid.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-009**
**Page 1 of 2**

**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference White testimony. Please provide a schedule in the same format as the response to STAFF-01, Q-STAFF-011 in DE 11-094 showing, by unit and month (for the Merrimack, Schiller and Newington units) MW modeled as on economic reserve shutdown and actual reserve shutdown conditions.

**Response:**
Please see the attached table.

**2011 - Economic Reserve Shutdown Hours**

| | Merrimack 1 | | | Merrimack 2 | | | Schiller 4 | | | Schiller 5 | | | Schiller 6 | | | Newington | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Economic Reserve Shutdown Hours | | | Economic Reserve Shutdown Hours | | | Economic Reserve Shutdown Hours | | | Economic Reserve Shutdown Hours | | | Economic Reserve Shutdown Hours | | | Economic Reserve Shutdown Hours | |
| 2011 | MWh/Hr | Modeled | Actual | MWh/Hr | Modeled | Actual | MWh/Hr | Modeled | Actual | MWh/Hr | Modeled | Actual | MWh/Hr | Modeled | Actual | MWh/Hr | Modeled | Actual |
| Jan | 114.0 | 0 | 4 | 343.0 | 0 | 0 | 48.0 | 0 | 141 | 42.6 | 0 | 0 | 48.6 | 0 | 27 | 400.2 | 694 | 460 |
| Feb | 114.0 | 0 | 0 | 343.0 | 0 | 0 | 48.0 | 0 | 0 | 42.6 | 0 | 0 | 48.6 | 0 | 0 | 400.2 | 644 | 560 |
| Mar | 114.0 | 0 | 0 | 343.0 | 0 | 18 | 48.0 | 0 | 71 | 42.6 | 0 | 0 | 48.6 | 0 | 14 | 400.2 | 594 | 590 |
| Apr | 114.0 | 0 | 0 | 343.0 | 0 | 62 | 48.0 | 0 | 256 | 42.6 | 0 | 0 | 48.6 | 0 | 0 | 400.2 | 474 | 493 |
| May | 114.0 | 377 | 53 | 343.0 | 0 | 572 | 48.0 | 744 | 140 | 42.6 | 0 | 0 | 48.6 | 744 | 335 | 400.2 | 744 | 744 |
| Jun | 112.5 | 0 | 445 | 338.4 | 0 | 0 | 47.5 | 0 | 592 | 43.1 | 0 | 0 | 47.9 | 0 | 666 | 400.2 | 692 | 710 |
| Jul | 112.5 | 0 | 258 | 338.4 | 0 | 0 | 47.5 | 0 | 438 | 43.1 | 0 | 0 | 47.9 | 0 | 336 | 400.2 | 664 | 605 |
| Aug | 112.5 | 0 | 0 | 338.4 | 0 | 323 | 47.5 | 0 | 645 | 43.1 | 0 | 0 | 47.9 | 0 | 658 | 400.2 | 692 | 695 |
| Sep | 112.5 | 0 | 0 | 338.4 | 0 | 720 | 47.5 | 0 | 582 | 43.1 | 0 | 0 | 47.9 | 0 | 587 | 400.2 | 720 | 628 |
| Oct | 114.0 | 0 | 192 | 343.0 | 0 | 277 | 48.0 | 353 | 1 | 42.6 | 0 | 0 | 48.6 | 744 | 617 | 400.2 | 744 | 590 |
| Nov | 114.0 | 0 | 0 | 343.0 | 0 | 0 | 48.0 | 0 | 438 | 42.6 | 0 | 0 | 48.6 | 0 | 709 | 400.2 | 720 | 656 |
| Dec | 114.0 | 0 | 0 | 343.0 | 0 | 359 | 48.0 | 0 | 744 | 42.6 | 0 | 0 | 48.6 | 0 | 733 | 400.2 | 728 | 744 |
| Total | 113.5 | 377 | 952 | 341.5 | 0 | 2,331 | 47.8 | 1,097 | 4,048 | 42.8 | 0 | 0 | 48.4 | 1,488 | 4,682 | 400.2 | 8,110 | 7,475 |

'Modeled' figures are from the Dec, 2010 ES rate filing.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-010**
**Page 1 of 2**

**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:
Reference White testimony. Please provide a schedule in the same format as the response to STAFF-01, Q-STAFF-012 in DE 11-094 showing, by unit and month (for the Merrimack, Schiller and Newington units) the modeled and actual reductions in unit capacity factors and availabilities (with planned maintenance outages excluded) due to economic reserve shutdown conditions.

## Response:
Please see the attached table.

## 2011 - Reductions in Capacity Factors Due to Economic Reserve Shutdown Status

Economic Reserve Shutdown Equivalent CFs

| | Merrimack 1 | | Merrimack 2 | | Schiller 4 | | Schiller 5 | | Schiller 6 | | Newington | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | Modeled | Actual | Modeled | Actual | Modeled | Actual | Modeled | Actual | Modeled | Actual | Modeled | Actual |
| Jan | 0.0% | 0.5% | 0.0% | 0.0% | 0.0% | 19.0% | 0.0% | 0.0% | 0.0% | 3.6% | 93.3% | 61.8% |
| Feb | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 95.8% | 83.3% |
| Mar | 0.0% | 0.0% | 0.0% | 2.4% | 0.0% | 9.5% | 0.0% | 0.0% | 0.0% | 1.9% | 79.8% | 79.3% |
| Apr | 0.0% | 0.0% | 0.0% | 8.6% | 0.0% | 35.6% | 0.0% | 0.0% | 0.0% | 0.0% | 65.8% | 68.5% |
| May | 50.7% | 7.1% | 0.0% | 76.9% | 100.0% | 18.8% | 0.0% | 0.0% | 100.0% | 45.0% | 100.0% | 100.0% |
| Jun | 0.0% | 61.8% | 0.0% | 0.0% | 0.0% | 82.2% | 0.0% | 0.0% | 0.0% | 92.5% | 96.1% | 98.6% |
| Jul | 0.0% | 34.7% | 0.0% | 0.0% | 0.0% | 58.9% | 0.0% | 0.0% | 0.0% | 45.2% | 89.2% | 81.3% |
| Aug | 0.0% | 0.0% | 0.0% | 43.4% | 0.0% | 86.7% | 0.0% | 0.0% | 0.0% | 88.4% | 93.0% | 93.4% |
| Sep | 0.0% | 0.0% | 0.0% | 100.0% | 0.0% | 80.8% | 0.0% | 0.0% | 0.0% | 81.5% | 100.0% | 87.2% |
| Oct | 0.0% | 25.8% | 0.0% | 37.2% | 47.4% | 0.1% | 0.0% | 0.0% | 100.0% | 82.9% | 100.0% | 79.3% |
| Nov | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 60.8% | 0.0% | 0.0% | 0.0% | 98.5% | 100.0% | 91.1% |
| Dec | 0.0% | 0.0% | 0.0% | 48.3% | 0.0% | 100.0% | 0.0% | 0.0% | 0.0% | 98.5% | 97.8% | 100.0% |
| Total | 4.3% | 10.9% | 0.0% | 26.6% | 12.5% | 46.2% | 0.0% | 0.0% | 17.0% | 53.4% | 92.6% | 85.3% |

'Modeled' figures are from the Dec, 2010 ES rate filing.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-011**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference White testimony. Please provide a update to the response to STAFF-01, Q-STAFF-016 in DE 11-094 describing PSNH's 2011 strategies to a) procure each energy product from the market to supplement PSNH resources, b) procure capacity to supplement PSNH resources, and c) acquire FTR's for each unit to manage congestion. If those strategies have changed from 2010, please explain the changes and reasons for those changes.

## Response:

The supplemental energy, capacity, and FTR purchase strategies for 2011 were not materially different from what was done for 2010.

a. Fundamentally, the starting point for determining how much supplemental energy was needed to meet ES energy requirements was to compare the expected economic operation of resources owned or contracted to PSNH, including IPP purchases, to its forecasted ES needs. PSNH's purchase strategy was to evaluate energy needs with due consideration of migration and high generating unit availability when considering supplemental energy purchases prior to the start of the delivery period, and managing any remaining energy purchase needs through bilateral and ISO-New England administered energy markets during the delivery period. Given the uncertainty of migration and the continuing sluggish economy during 2011, PSNH did not make any energy purchases more than a week in advance of delivery, other than two 2011 annual energy purchases transacted in 2008. Ultimately in 2011, PSNH's energy purchase strategy resulted in near term purchases made for durations of one month and less.

b. PSNH does not have to hold in its name the amount of capacity needed to serve energy service customer requirements. PSNH is paid for the capacity it holds and pays for its share of ISO-NE capacity market costs resulting from serving energy service customer load. Because any shortfall would be handled automatically in the ISO-NE capacity market settlement system at prices that were known for 2011 since late 2008, PSNH did not procure capacity other than through the ISO-NE capacity market system. Additionally, had it desired to do so, it would have been difficult to know the quantity to procure due to the migration of customers to 3rd party suppliers.

c. PSNH procures FTRs to hedge the potential for congestion between significant supply resources (Merrimack, Schiller, Newington, delivery location for bilateral purchases (e.g. - Mass. Hub)) and the New Hampshire load zone. 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.

**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference White testimony. Please provide a schedule in the same format as the response to STAFF-01, Q-STAFF-017 in DE 11-094 showing the modeled and actual monthly customer migration in MW and MWh.

**Response:**
Please see the attached table.

## 2011 Capacity and Energy Obligations

| | Actual | | | | | | Model Assumptions | |
|---|---|---|---|---|---|---|---|---|
| | Total PSNH | | ES | | 3rd Party Supply | | ES | |
| 2011 | MW-Mnths | MWh | MW-Mnths | MWh | MW-Mnths | MWh | MW-Mnths | MWh |
| Jan | 2,124 | 749,336 | 1,430 | 517,681 | 694 | 231,655 | 1,427 | 523,337 |
| Feb | 2,124 | 661,321 | 1,425 | 455,279 | 700 | 206,041 | 1,427 | 463,612 |
| Mar | 2,211 | 686,711 | 1,478 | 459,080 | 733 | 227,632 | 1,489 | 467,179 |
| Apr | 2,206 | 618,811 | 1,469 | 399,746 | 737 | 219,065 | 1,480 | 427,258 |
| May | 2,206 | 657,887 | 1,462 | 411,504 | 744 | 246,383 | 1,480 | 428,505 |
| Jun | 2,219 | 678,677 | 1,458 | 439,581 | 761 | 239,096 | 1,412 | 435,282 |
| Jul | 2,187 | 802,300 | 1,450 | 540,239 | 737 | 262,061 | 1,412 | 502,724 |
| Aug | 2,187 | 754,290 | 1,445 | 492,252 | 742 | 262,038 | 1,412 | 481,054 |
| Sep | 2,187 | 672,198 | 1,445 | 427,890 | 742 | 244,308 | 1,425 | 431,479 |
| Oct | 2,199 | 648,593 | 1,449 | 403,366 | 750 | 245,226 | 1,425 | 426,870 |
| Nov | 2,199 | 636,599 | 1,443 | 412,867 | 756 | 223,732 | 1,425 | 433,464 |
| Dec | 2,203 | 716,983 | 1,432 | 475,394 | 771 | 241,589 | 1,413 | 474,592 |
| Total | 26,251 | 8,283,706 | 17,384 | 5,434,880 | 8,866 | 2,848,825 | 17,229 | 5,495,357 |

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-013**
**Page 1 of 2**

**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference White testimony, page 7 (Bates 56), lines 6-9. Please individually list by month the FTR amounts procured for Merrimack, Schiller, and Newington stations, their cost, and the related congestion savings/expense.

**Response:**
Please see the attached table.

**2011 FTR Activity and Valuation for Merrimack, Schiller and Newington**

| Source | Month | FTR MW Quantity Peak | FTR MW Quantity Off-Peak | | Corresponding Cost and Value of FTRs (Expense) / Revenue FTR Auction $ | FTR Value $ | Net FTR $ |
|---|---|---|---|---|---|---|---|
| **Merrimack** | Jan - Dec | 0 | 0 | | 0 | 0 | 0 |
| | Jan | 251 | 200 | | (12,618) | 410 | (12,208) |
| | Feb | 285 | 246 | | (9,807) | (3) | (9,810) |
| | Mar | 188 | 90 | | (5,790) | 97 | (5,693) |
| | Apr | 0 | 0 | | 0 | 0 | 0 |
| | May | 118 | 0 | | (9,887) | 580 | (9,307) |
| | Jun | 86 | 85 | | (1,871) | 844 | (1,027) |
| | Jul | 60 | 78 | | (2,253) | (10) | (2,263) |
| | Aug | 160 | 85 | | (6,527) | 11 | (6,516) |
| | Sep | 87 | 0 | | (5,856) | (39) | (5,895) |
| | Oct | 0 | 50 | | (322) | 406 | 85 |
| | Nov | 85 | 85 | | (1,227) | 2,848 | 1,621 |
| | Dec | 100 | 50 | | (1,819) | (21) | (1,840) |
| | | | | Total | (57,978) | 5,124 | (52,854) |
| **Schiller** | Jan - Dec | 0 | 0 | | 0 | 0 | 0 |
| | Jan | 120 | 90 | | (1,525) | 309 | (1,216) |
| | Feb | 120 | 90 | | (746) | (8) | (755) |
| | Mar | 80 | 65 | | (418) | (106) | (523) |
| | Apr | 40 | 0 | | 106 | 5 | 111 |
| | May | 0 | 0 | | 0 | 0 | 0 |
| | Jun | 40 | 40 | | (372) | 869 | 497 |
| | Jul | 75 | 40 | | (1,642) | (301) | (1,943) |
| | Aug | 90 | 40 | | (1,048) | (339) | (1,387) |
| | Sep | 40 | 40 | | 27 | (44) | (17) |
| | Oct | 0 | 0 | | 0 | 0 | 0 |
| | Nov | 25 | 40 | | (426) | 888 | 462 |
| | Dec | 75 | 25 | | (803) | (20) | (823) |
| | | | | Total | (6,846) | 1,253 | (5,593) |
| **Newington** | Jan - Dec | 0 | 0 | | 0 | 0 | 0 |
| | Jan | 0 | 0 | | 0 | 0 | 0 |
| | Feb | 0 | 0 | | 0 | 0 | 0 |
| | Mar | 0 | 0 | | 0 | 0 | 0 |
| | Apr | 0 | 0 | | 0 | 0 | 0 |
| | May | 0 | 0 | | 0 | 0 | 0 |
| | Jun | 0 | 0 | | 0 | 0 | 0 |
| | Jul | 0 | 0 | | 0 | 0 | 0 |
| | Aug | 0 | 0 | | 0 | 0 | 0 |
| | Sep | 0 | 0 | | 0 | 0 | 0 |
| | Oct | 0 | 0 | | 0 | 0 | 0 |
| | Nov | 0 | 0 | | 0 | 0 | 0 |
| | Dec | 0 | 0 | | 0 | 0 | 0 |
| | | | | Total | 0 | 0 | 0 |
| | | | | **Total Above** | (64,824) | 6,377 | (58,447) |

Notes:
Jan.-Dec. FTR cost and value are allocated monthly as per ISO-NE Billing methodology.
FTR Auction $ - this is the amount paid to (-) or received from (+) ISO based on the auction clearing price of awarded FTRs.
FTR Value $ - this is the amount paid to (-) or received from (+) ISO based on the realized value of the awarded FTRs.
Net FTR $ - the sum of the auction dollars and market value of the awarded FTRs.
[FTR Value includes refund of under-funded target allocations via the ISO-NE Congestion Revenue Fund.]

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-014**
**Page 1 of 2**

**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference White testimony, page 7 (Bates 56), line 9. Please provide the supporting calculations for the energy service expense of $22,560 related to the FTR acquisitions.

**Response:**

As discussed in testimony, PSNH acquires FTRs for resources it expects to operate during the applicable period. PSNH's strategy is to convert a variable congestion value into a fixed value via the FTR auction. Put another way, PSNH procures FTRs primarily to provide cost certainty and thus reduce risk, rather than to achieve savings. The variable congestion value is what PSNH avoided or gave up in exchange for a fixed value. The $22,560 is the difference between what the variable congestion cost would have been (-$6,664), and the fixed cost from the FTR auction ($15,896). The attached table below builds on the information provided in Staff-1, Q-Staff-13 to show the derivation of the $22,560.

## 2011 Total FTR Activity and Valuation

| Source | Month | FTR MW Quantity Peak | FTR MW Quantity Off-Peak | | Corresponding Cost and Value of FTRs (Expense) / Revenue FTR Auction $ | FTR Value $ | Net FTR $ |
|---|---|---|---|---|---|---|---|
| | **2011 Total of Merrimack, Schiller & Newington** | | | | (64,824) | 6,377 | (58,447) |
| **Other** | Jan - Dec | 25 | 0 | | | | |
| | Jan | 0 | 0 | | 2,050 | 29 | 2,079 |
| | Feb | 0 | 0 | | 1,852 | 18 | 1,869 |
| | Mar | 0 | 0 | | 2,050 | 492 | 2,542 |
| | Apr | 43 | 0 | | 2,556 | 31 | 2,587 |
| | May | 93 | 0 | | 3,919 | (3,852) | 67 |
| | Jun | 57 | 0 | | 3,472 | (7,186) | (3,714) |
| | Jul | 68 | 18 | | 5,968 | 385 | 6,352 |
| | Aug | 50 | 0 | | 3,856 | (230) | 3,626 |
| | Sep | 85 | 10 | | 4,627 | 97 | 4,724 |
| | Oct | 75 | 0 | | 9,768 | 1,779 | 11,547 |
| | Nov | 93 | 18 | | 5,338 | (4,724) | 615 |
| | Dec | 32 | 18 | | 3,473 | 121 | 3,594 |
| | | | | Total | 48,928 | (13,040) | 35,887 |
| | | | | **Total All Above** | (15,896) | (6,664) | (22,560) |

Notes:
Other FTR MWs include those that were purchased to address bilateral and Vermont Yankee purchases.
Jan.-Dec. FTR Auction and Value dollars are allocated monthly as per ISO-NE Billing methodology.
FTR Auction $ - this is the amount paid to (-) or received from (+) ISO based on the auction clearing price of awarded FTRs.
FTR Value $ - this is the amount paid to (-) or received from (+) ISO based on the realized value of the awarded FTRs.
Net FTR $ - the sum of the auction dollars and market value of the awarded FTRs.
[FTR Value includes refund of under-funded target allocations via the ISO-NE Congestion Revenue Fund.]

**Witness:** Frederick White
**Request from:** New Hampshire Public Utilities Commission Staff

## Question:

Reference White testimony, Attachment FBW-2 and FBW-3 (Bates 58 and 59). Please provide by month for on-peak, off-peak, and total values and in the form provided in previous dockets (see the response to STAFF-01, Q-STAFF-027 in DE 11-094): a.Information on bilateral purchases and costs, spot purchases and costs, and sales on surplus purchases
b.Actual bilateral and spot purchase quantities compared to those in the rate request in both tabular and graphic form. c.Total supplemental purchases and percent breakdown by monthly bilateral, short term bilateral and spot purchases. d.Spot sale energy and value to ISO-NE from PSNH units and bilateral surplus sales.

## Response:

Please see the attached tables.

## 2011 - Summary of PSNH Bilateral Purchases and ISO-NE Spot Purchases & Sales

### Peak

| 2011 | Total Bilateral Purchases MWh | Total Bilateral Purchases $000 | Ave. Price $/MWh | Sales of Surplus Purchases MWh | Percent (%) Sold as Surplus | Profit / (Loss) on Sales $000 | Total ISO-NE Spot Purchases MWh | Total ISO-NE Spot Purchases $000 | Avg Price $/MWh |
|---|---|---|---|---|---|---|---|---|---|
| Jan | 48,000 | 4,013 | 83.60 | 9,473 | 20% | (172) | 8,857 | 720 | 81.30 |
| Feb | 32,000 | 2,768 | 86.50 | 12,954 | 40% | (352) | 4,362 | 336 | 76.99 |
| Mar | 36,800 | 3,183 | 86.50 | 18,495 | 50% | (702) | 7,535 | 450 | 59.71 |
| Apr | 56,800 | 3,990 | 70.24 | 8,255 | 15% | (255) | 17,839 | 825 | 46.23 |
| May | 100,800 | 5,933 | 58.86 | 11,792 | 12% | (158) | 14,674 | 772 | 52.60 |
| Jun | 40,800 | 3,532 | 86.56 | 850 | 2% | (33) | 49,982 | 2,529 | 50.59 |
| Jul | 32,000 | 2,768 | 86.50 | 55 | 0% | 0 | 47,652 | 2,918 | 61.25 |
| Aug | 53,600 | 3,968 | 74.03 | 4 | 0% | (4) | 84,855 | 4,214 | 49.66 |
| Sep | 93,600 | 5,568 | 59.49 | 0 | 0% | 0 | 55,206 | 2,560 | 46.36 |
| Oct | 84,800 | 5,411 | 63.81 | 16 | 0% | (1) | 30,136 | 1,419 | 47.08 |
| Nov | 69,600 | 4,573 | 65.71 | 1,703 | 2% | (93) | 25,898 | 1,133 | 43.73 |
| Dec | 84,000 | 4,964 | 59.09 | 3,076 | 4% | (159) | 34,634 | 1,548 | 44.69 |
| Total | 732,800 | 50,671 | 69.15 | 66,672 | 9% | (1,928) | 381,632 | 19,422 | 50.89 |

### Off-Peak

| 2011 | Total Bilateral Purchases MWh | Total Bilateral Purchases $000 | Ave. Price $/MWh | Sales of Surplus Purchases MWh | Percent (%) Sold as Surplus | Profit / (Loss) on Sales $000 | Total ISO-NE Spot Purchases MWh | Total ISO-NE Spot Purchases $000 | Avg Price $/MWh |
|---|---|---|---|---|---|---|---|---|---|
| Jan | 0 | 0 | 0.00 | 0 | 0% | 0 | 11,781 | 716 | 60.80 |
| Feb | 0 | 0 | 0.00 | 0 | 0% | 0 | 12,867 | 661 | 51.35 |
| Mar | 0 | 0 | 0.00 | 0 | 0% | 0 | 25,899 | 1,099 | 42.45 |
| Apr | 15,200 | 623 | 40.99 | 0 | 0% | 0 | 30,690 | 1,247 | 40.62 |
| May | 70,800 | 3,111 | 43.95 | 8,243 | 12% | (84) | 36,192 | 1,539 | 42.54 |
| Jun | 0 | 0 | 0.00 | 0 | 0% | 0 | 35,780 | 1,421 | 39.72 |
| Jul | 0 | 0 | 0.00 | 0 | 0% | 0 | 84,524 | 3,858 | 45.65 |
| Aug | 12,800 | 590 | 46.09 | 0 | 0% | 0 | 80,272 | 3,388 | 42.21 |
| Sep | 32,800 | 1,363 | 41.56 | 0 | 0% | 0 | 96,757 | 3,732 | 38.57 |
| Oct | 28,800 | 1,308 | 45.40 | 319 | 1% | (23) | 77,950 | 3,051 | 39.14 |
| Nov | 0 | 0 | 0.00 | 0 | 0% | 0 | 68,057 | 2,526 | 37.11 |
| Dec | 24,800 | 975 | 39.31 | 0 | 0% | 0 | 74,000 | 2,511 | 33.93 |
| Total | 185,200 | 7,970 | 43.03 | 8,562 | 5% | (107) | 634,770 | 25,750 | 40.57 |

### Total

| 2011 | Total Bilateral Purchases MWh | Total Bilateral Purchases $000 | Ave. Price $/MWh | Sales of Surplus Purchases MWh | Percent (%) Sold as Surplus | Profit / (Loss) on Sales $000 | Total ISO-NE Spot Purchases MWh | Total ISO-NE Spot Purchases $000 | Avg Price $/MWh |
|---|---|---|---|---|---|---|---|---|---|
| Jan | 48,000 | 4,013 | 83.60 | 9,473 | 20% | (172) | 20,638 | 1,436 | 69.60 |
| Feb | 32,000 | 2,768 | 86.50 | 12,954 | 40% | (352) | 17,230 | 997 | 57.84 |
| Mar | 36,800 | 3,183 | 86.50 | 18,495 | 50% | (702) | 33,434 | 1,549 | 46.34 |
| Apr | 72,000 | 4,613 | 64.07 | 8,255 | 11% | (255) | 48,529 | 2,071 | 42.68 |
| May | 171,600 | 9,044 | 52.71 | 20,035 | 12% | (242) | 50,865 | 2,311 | 45.44 |
| Jun | 40,800 | 3,532 | 86.56 | 850 | 2% | (33) | 85,763 | 3,950 | 46.06 |
| Jul | 32,000 | 2,768 | 86.50 | 55 | 0% | 0 | 132,176 | 6,777 | 51.27 |
| Aug | 66,400 | 4,558 | 68.64 | 4 | 0% | (4) | 165,127 | 7,602 | 46.04 |
| Sep | 126,400 | 6,932 | 54.84 | 0 | 0% | 0 | 151,963 | 6,292 | 41.40 |
| Oct | 113,600 | 6,719 | 59.14 | 335 | 0% | (24) | 108,086 | 4,470 | 41.35 |
| Nov | 69,600 | 4,573 | 65.71 | 1,703 | 2% | (93) | 93,955 | 3,658 | 38.94 |
| Dec | 108,800 | 5,939 | 54.58 | 3,076 | 3% | (159) | 108,635 | 4,059 | 37.36 |
| Total | 918,000 | 58,641 | 63.88 | 75,235 | 8% | (2,036) | 1,016,402 | 45,172 | 44.44 |

# 2011 - Summary of PSNH Bilateral and Spot Purchases

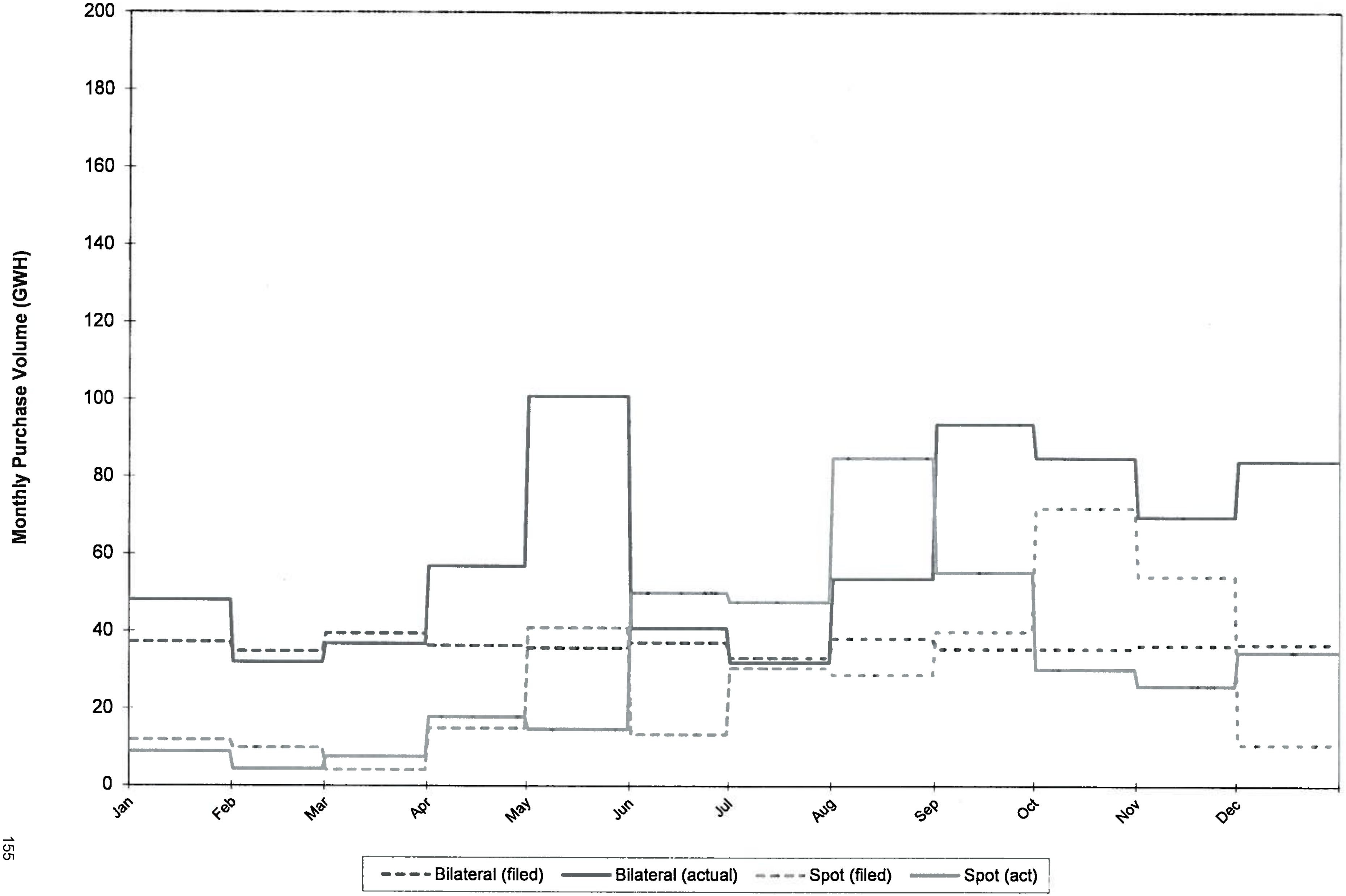
## Peak

| | Actual 2011 Purchase Quantities | | Purchase Quantities Filed with Rate Request | |
|---|---|---|---|---|
| 2011 | Total Bilateral Purchases MWh | Total ISO-NE Spot Purchases MWh | Total Bilateral Purchases MWh | Total ISO-NE Spot Purchases MWh |
| 1 | 48,000 | 8,857 | 37,229 | 11,857 |
| 2 | 32,000 | 4,362 | 34,880 | 9,846 |
| 3 | 36,800 | 7,535 | 39,450 | 4,101 |
| 4 | 56,800 | 17,839 | 36,322 | 14,904 |
| 5 | 100,800 | 14,674 | 35,717 | 40,906 |
| 6 | 40,800 | 49,982 | 37,101 | 13,397 |
| 7 | 32,000 | 47,652 | 33,152 | 30,474 |
| 8 | 53,600 | 84,855 | 38,125 | 28,770 |
| 9 | 93,600 | 55,206 | 35,414 | 39,855 |
| 10 | 84,800 | 30,136 | 35,414 | 71,804 |
| 11 | 69,600 | 25,898 | 36,322 | 54,201 |
| 12 | 84,000 | 34,634 | 36,624 | 10,718 |
| Totals | 732,800 | 381,632 | 435,749 | 330,834 |

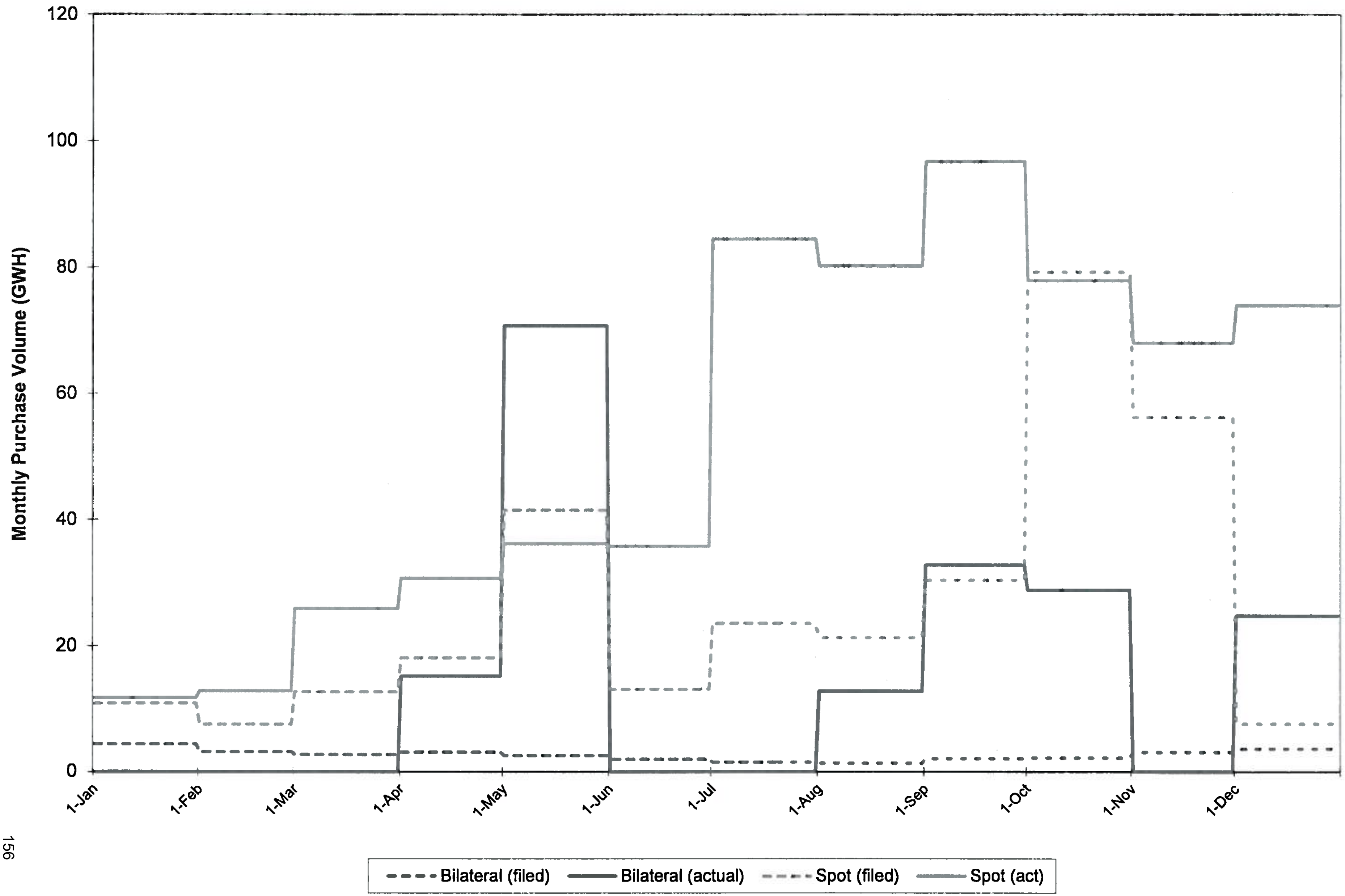
## Off-Peak

| 2011 | Total Bilateral Purchases MWh | Total ISO-NE Spot Purchases MWh | Total Bilateral Purchases MWh | Total ISO-NE Spot Purchases MWh |
|---|---|---|---|---|
| 1 | 0 | 11,781 | 4,406 | 10,900 |
| 2 | 0 | 12,867 | 3,168 | 7,547 |
| 3 | 0 | 25,899 | 2,707 | 12,693 |
| 4 | 15,200 | 30,690 | 3,110 | 18,121 |
| 5 | 70,800 | 36,192 | 2,570 | 41,523 |
| 6 | 0 | 35,780 | 1,987 | 13,093 |
| 7 | 0 | 84,524 | 1,526 | 23,566 |
| 8 | 12,800 | 80,272 | 1,354 | 21,266 |
| 9 | 32,800 | 96,757 | 2,074 | 30,381 |
| 10 | 28,800 | 77,950 | 2,203 | 79,268 |
| 11 | 0 | 68,057 | 3,110 | 56,217 |
| 12 | 24,800 | 74,000 | 3,672 | 7,622 |
| Totals | 185,200 | 634,770 | 31,889 | 322,196 |

## 2011 Peak Bilateral and Spot Purchase Activity (Actual vs Originally Filed)



## 2011 Off-Peak Bilateral and Spot Purchase Activity (Actual vs Originally Filed)



## Summary of PSNH Supplemental Purchases

| | Peak Power | | | | Off-Peak Power | | | |
|---|---|---|---|---|---|---|---|---|
| Month | Total Supplemental Purchases MWh | % Monthly Bilateral Purchases | % Short-Term Bilateral Purchases | % ISO-NE Spot Market Purchases | Total Supplemental Purchases MWh | % Monthly Bilateral Purchases | % Short-Term Bilateral Purchases | % ISO-NE Spot Market Purchases |
| Jan-07 | 73,910 | 54.9% | 22.7% | 22.3% | 75,638 | 89.9% | 0.0% | 10.1% |
| Feb-07 | 50,642 | 73.0% | 11.1% | 16.0% | 70,540 | 86.7% | 4.5% | 8.8% |
| Mar-07 | 115,478 | 65.6% | 25.6% | 8.7% | 58,315 | 80.9% | 0.0% | 19.1% |
| Apr-07 | 157,269 | 88.5% | 1.0% | 10.5% | 78,215 | 58.6% | 4.1% | 37.3% |
| May-07 | 194,826 | 74.6% | 6.4% | 19.1% | 112,347 | 76.2% | 0.0% | 23.8% |
| Jun-07 | 148,246 | 82.8% | 9.2% | 8.1% | 72,858 | 64.0% | 8.8% | 27.2% |
| Jul-07 | 181,284 | 77.0% | 14.1% | 8.9% | 89,081 | 79.4% | 0.0% | 20.6% |
| Aug-07 | 193,398 | 88.6% | 2.1% | 9.4% | 92,606 | 67.5% | 13.8% | 18.7% |
| Sep-07 | 152,442 | 72.9% | 16.8% | 10.3% | 103,988 | 51.4% | 21.5% | 27.0% |
| Oct-07 | 133,175 | 73.4% | 10.2% | 16.4% | 57,284 | 75.4% | 0.0% | 24.6% |
| Nov-07 | 107,760 | 82.7% | 0.0% | 17.3% | 54,579 | 85.7% | 0.0% | 14.3% |
| Dec-07 | 133,305 | 87.7% | 0.0% | 12.3% | 79,321 | 68.3% | 0.0% | 31.7% |
| Jan-08 | 148,687 | 62.8% | 23.7% | 13.5% | 71,454 | 56.0% | 1.1% | 42.9% |
| Feb-08 | 134,171 | 78.9% | 6.0% | 15.1% | 75,806 | 47.3% | 12.7% | 40.0% |
| Mar-08 | 146,361 | 82.7% | 9.8% | 7.5% | 78,824 | 71.1% | 2.5% | 26.3% |
| Apr-08 | 238,479 | 99.6% | 0.0% | 0.4% | 150,309 | 84.3% | 0.0% | 15.7% |
| May-08 | 214,361 | 99.2% | 0.0% | 0.8% | 153,132 | 95.1% | 0.0% | 4.9% |
| Jun-08 | 201,567 | 80.7% | 14.3% | 5.0% | 118,042 | 50.1% | 14.9% | 35.0% |
| Jul-08 | 215,916 | 70.6% | 12.6% | 16.8% | 151,912 | 39.4% | 16.3% | 44.3% |
| Aug-08 | 164,809 | 87.6% | 2.4% | 10.0% | 84,180 | 77.7% | 0.0% | 22.3% |
| Sep-08 | 180,327 | 80.6% | 0.0% | 19.4% | 111,527 | 41.8% | 0.0% | 58.2% |
| Oct-08 | 157,982 | 66.1% | 0.0% | 33.9% | 78,611 | 56.0% | 0.0% | 44.0% |
| Nov-08 | 121,363 | 70.4% | 7.9% | 21.6% | 74,481 | 68.5% | 0.0% | 31.5% |
| Dec-08 | 122,458 | 80.5% | 3.3% | 16.3% | 62,054 | 73.4% | 0.0% | 26.6% |
| Jan-09 | 101,908 | 76.5% | 9.4% | 14.1% | 78,400 | 89.3% | 2.0% | 8.6% |
| Feb-09 | 116,667 | 60.8% | 21.3% | 18.0% | 93,777 | 67.6% | 9.4% | 23.1% |
| Mar-09 | 97,466 | 97.5% | 0.0% | 2.5% | 53,158 | 94.7% | 0.0% | 5.3% |
| Apr-09 | 153,880 | 97.9% | 0.0% | 2.1% | 85,719 | 91.0% | 0.0% | 9.0% |
| May-09 | 102,878 | 87.7% | 0.0% | 12.3% | 63,863 | 81.5% | 0.0% | 18.5% |
| Jun-09 | 139,494 | 96.7% | 2.3% | 1.0% | 59,754 | 73.8% | 16.1% | 10.1% |
| Jul-09 | 138,618 | 88.8% | 3.5% | 7.7% | 55,855 | 80.4% | 0.0% | 19.6% |
| Aug-09 | 208,363 | 82.4% | 2.3% | 15.3% | 181,439 | 77.6% | 2.6% | 19.8% |
| Sep-09 | 197,340 | 99.6% | 0.0% | 0.4% | 136,060 | 91.1% | 0.0% | 8.9% |
| Oct-09 | 175,107 | 97.5% | 0.0% | 2.5% | 134,834 | 93.6% | 0.0% | 6.4% |
| Nov-09 | 156,225 | 99.2% | 0.0% | 0.8% | 133,936 | 96.0% | 0.0% | 4.0% |
| Dec-09 | 115,172 | 86.6% | 4.9% | 8.5% | 62,484 | 75.5% | 0.0% | 24.5% |
| Jan-10 | 67,439 | 87.5% | 0.0% | 12.5% | 61,517 | 23.7% | 10.4% | 65.9% |
| Feb-10 | 71,079 | 83.3% | 6.8% | 10.0% | 24,877 | 48.5% | 0.0% | 51.5% |
| Mar-10 | 68,285 | 99.3% | 0.0% | 0.7% | 17,521 | 74.7% | 0.0% | 25.3% |
| Apr-10 | 73,397 | 85.0% | 0.0% | 15.0% | 31,343 | 34.4% | 0.0% | 65.6% |
| May-10 | 75,573 | 75.4% | 0.0% | 24.6% | 46,155 | 22.9% | 13.9% | 63.3% |
| Jun-10 | 72,635 | 89.0% | 0.0% | 11.0% | 29,674 | 39.9% | 0.0% | 60.1% |
| Jul-10 | 84,048 | 74.0% | 0.0% | 26.0% | 62,204 | 22.9% | 11.6% | 65.5% |
| Aug-10 | 84,106 | 77.7% | 11.4% | 10.9% | 36,665 | 38.0% | 0.0% | 62.0% |
| Sep-10 | 86,514 | 72.0% | 12.9% | 15.0% | 41,542 | 32.9% | 15.4% | 51.7% |
| Oct-10 | 139,480 | 44.3% | 31.5% | 24.1% | 111,809 | 12.5% | 37.2% | 50.3% |
| Nov-10 | 119,323 | 107.9% | -18.8% | 10.8% | 83,138 | 107.1% | -33.7% | 26.6% |
| Dec-10 | 69,490 | 97.3% | 0.0% | 2.7% | 17,835 | 71.8% | 0.0% | 28.2% |
| Jan-11 | 56,857 | 59.1% | 25.3% | 15.6% | 11,781 | 0.0% | 0.0% | 100.0% |
| Feb-11 | 36,362 | 88.0% | 0.0% | 12.0% | 12,867 | 0.0% | 0.0% | 100.0% |
| Mar-11 | 44,335 | 83.0% | 0.0% | 17.0% | 25,899 | 0.0% | 0.0% | 100.0% |
| Apr-11 | 74,639 | 45.0% | 31.1% | 23.9% | 45,890 | 0.0% | 33.1% | 66.9% |
| May-11 | 115,474 | 87.3% | 0.0% | 12.7% | 106,992 | 57.2% | 9.0% | 33.8% |
| Jun-11 | 90,782 | 38.8% | 6.2% | 55.1% | 35,780 | 0.0% | 0.0% | 100.0% |
| Jul-11 | 79,652 | 40.2% | 0.0% | 59.8% | 84,524 | 0.0% | 0.0% | 100.0% |
| Aug-11 | 138,455 | 26.6% | 12.1% | 61.3% | 93,072 | 0.0% | 13.8% | 86.2% |
| Sep-11 | 148,806 | 22.6% | 40.3% | 37.1% | 129,557 | 0.0% | 25.3% | 74.7% |
| Oct-11 | 114,936 | 29.2% | 44.5% | 26.2% | 106,750 | 0.0% | 27.0% | 73.0% |
| Nov-11 | 95,498 | 35.2% | 37.7% | 27.1% | 68,057 | 0.0% | 0.0% | 100.0% |
| Dec-11 | 118,634 | 28.3% | 42.5% | 29.2% | 98,800 | 0.0% | 25.1% | 74.9% |
| Year | | | | | | | | |
| 2007 | 1,641,733 | 78.3% | 9.0% | 12.6% | 944,774 | 72.5% | 5.1% | 22.4% |
| 2008 | 2,046,482 | 81.3% | 6.4% | 12.3% | 1,210,332 | 64.1% | 4.5% | 31.4% |
| 2009 | 1,703,118 | 90.2% | 3.1% | 6.7% | 1,139,279 | 85.1% | 2.2% | 12.7% |
| 2010 | 1,011,370 | 80.9% | 4.7% | 14.4% | 564,281 | 40.9% | 7.1% | 52.1% |
| 2011 | 1,114,432 | 42.6% | 23.1% | 34.2% | 819,970 | 7.5% | 15.1% | 77.4% |

## 2011 - Summary of PSNH Spot Sales

### Peak

| 2011 | Total ISO-NE Spot Sales MWh | Surplus Sales from Generation MWh | Surplus Sales from Bilateral MWh | Total ISO-NE Spot Sales $000 | Ave. Sale $/MWh |
|---|---|---|---|---|---|
| Jan | 21,425 | 11,952 | 9,473 | 2,069 | 96.59 |
| Feb | 20,748 | 7,794 | 12,954 | 1,492 | 71.93 |
| Mar | 21,461 | 2,966 | 18,495 | 1,047 | 48.78 |
| Apr | 9,156 | 901 | 8,255 | 507 | 55.43 |
| May | 11,808 | 17 | 11,792 | 537 | 45.47 |
| Jun | 1,277 | 427 | 850 | 73 | 57.28 |
| Jul | 1,938 | 1,884 | 55 | 331 | 170.94 |
| Aug | 275 | 270 | 4 | 158 | 574.95 |
| Sep | 150 | 150 | 0 | 29 | 194.21 |
| Oct | 6,296 | 6,280 | 16 | 248 | 39.39 |
| Nov | 4,259 | 2,555 | 1,703 | 166 | 38.89 |
| Dec | 3,115 | 39 | 3,076 | 76 | 24.31 |
| Totals | 101,908 | 35,235 | 66,672 | 6,734 | 66.08 |

### Off-Peak

| 2011 | Total ISO-NE Spot Sales MWh | Surplus Sales from Generation MWh | Surplus Sales from Bilateral MWh | Total ISO-NE Spot Sales $000 | Ave. Sale $/MWh |
|---|---|---|---|---|---|
| Jan | 38,415 | 38,415 | 0 | 2,610 | 67.93 |
| Feb | 21,410 | 21,410 | 0 | 1,250 | 58.38 |
| Mar | 14,171 | 14,171 | 0 | 501 | 35.33 |
| Apr | 12,237 | 12,237 | 0 | 469 | 38.35 |
| May | 9,037 | 794 | 8,243 | 302 | 33.39 |
| Jun | 4,725 | 4,725 | 0 | 169 | 35.81 |
| Jul | 349 | 349 | 0 | 25 | 72.76 |
| Aug | 22 | 22 | 0 | 1 | 31.35 |
| Sep | 0 | 0 | 0 | 0 | 0.00 |
| Oct | 393 | 74 | 319 | (13) | (33.15) |
| Nov | 11,641 | 11,641 | 0 | 320 | 27.50 |
| Dec | 8,216 | 8,216 | 0 | 194 | 23.58 |
| Totals | 120,616 | 112,053 | 8,562 | 5,827 | 48.31 |

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**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-016**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

For 2011, please list all events caused by PSNH/NU distribution and/or transmission personnel or their contractors that caused a trip of any generator. For each such event, please state whether replacement power was required or not, the date of occurrence, and the party responsible. Please also indicate if PSNH supervision was present if the event was caused by a contractor. Do not include as part of your response events caused by equipment failure, faults, lightning, etc.

## Response:

One generator outage in 2011 was caused by distribution/transmission/contractor personnel.

On November 1, 2011, contractor I. C. Reed was assisting PSNH during storm restoration following the heavy, wet snowstorm at the end of October. A cutout door was misaligned when the crew attempted to close it, causing an equipment failure and outage to the distribution circuit and Hooksett Hydro. Hooksett Hydro is a 1.6 MW unit and the outage lasted one hour and 23 minutes. PSNH supervision was not present at the time of the event.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-017**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, page 3 (Bates 64), lines 5-6. Please provide the PSNH generation fleet overall availability during 2011 with and without planned maintenance outages.

**Response:**
The PSNH Generation fleet overall equivalent availability during 2011 with planned outages included is provided in WHS-3 as 88.1%. The Generation fleet overall equivalent availability with planned outages removed is 95.1%.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-018**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, page 6 (Bates 67). Please explain why the table detailing unplanned outages includes OR-5 which is described as a "planned" preventative maintenance outage at Newington Station.

**Response:**
OR-5 was a preventative maintenance outage, not Newington Station's scheduled annual outage, so it is characterized as an "unplanned" outage and listed in the unplanned outage table. Newington's scheduled annual outage which occurred in the spring, was included in the long term planning with the NE-ISO and is listed in the Scheduled Outage Table. Notwithstanding the characterization of OR-5 as "unplanned", Generation Management did plan this preventative maintenance outage work and coordinated the scheduling of this outage with ISO-NE. OR-5 was a brief 2.2 day outage that PSNH planned and scheduled to ensure Newington was in optimal dispatch condition for the upcoming winter operating season. This "planned" term has been used often historically to indicate maintenance type work at the units that is planned and coordinated with NE-ISO prior to removing the unit from service outside of the "Scheduled Outages" completed on a cyclic basis at all of the units. These preventative-type outages can be scheduled weeks or months in advance and provide economic value to customers.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-019**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, Appendix A, page 6 (Bates 78). With respect to the 355 ROW and the 355X10 distribution circuit, both include the statement that regaining the full width of the ROW commenced after the normal tree trimming cycle. When did regaining the full width of the ROWs occur? How much of the full ROW had not previously been trimmed?

## Response:

The 355 ROW has been patrolled to identify the edges of the right-of-way and compared those results with the portion that has been maintained to date. PSNH is in the process of mowing the ROW, but no full width clearing has been started. The ROW is 100 feet wide and PSNH has historically maintained approximately 35 feet on each side of the pole line (70 feet total width).

The 355x10 circuit is approximately 90% roadside. The remaining 10% in ROW will be trimmed to full width at the same time as the main line 355 ROW.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-020**


**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, Appendix A, page 7 (Bates 79). With respect to the patrol that took place between 11/28/11 and 12/30/11, please explain why the hazard trees identified during that patrol were not identified at the time of the response to the 7/26/10 outage.

## Response:

The restoration effort on 7/26/10 which occurred on the 335/332 ROW did not include a full patrol. When crews respond to a tree related outage in a ROW, a localized inspection is conducted, not a full line patrol. Immediate threats to the line are identified and corrected in the vicinity of the tree that caused the outage. Only localized inspections are completed for tree related outages that occur in ROWs because of the length of these circuits and the limited access. The 2011 patrol was done in response to Commission Order No. 25,321 in Docket No. DE 11-094 approving the 2010 ES/SCRC stipulation, and was a more in depth inspection consistent with the inspection practices used during scheduled maintenance, such as mowing or side trimming.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-01**
**Dated: 06/27/2012**
**Q-STAFF-021**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, Appendix A, page 11 (Bates 83). Please supply the missing information with respect to when the equipment will be installed at the Canaan hydro unit.

## Response:

Appendix A, page 11 statement should read: The disturbance monitoring equipment is scheduled to be installed at Canaan during the July 2012 Annual Inspection. The testimony will be corrected at the hearing.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request OCA-01**
**Dated: 06/26/2012**
**Q-OCA-010**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **Office of Consumer Advocate**

## Question:

Reference Testimony of Frederick B. White at page 7 (Bates 000056), lines 6-9. Has PSNH performed an analysis of the FTRs procured and settled to determine if participation in the FTR auction process during 2011 resulted in a net benefit to customers?

## Response:

Yes. PSNH's FTR activities during 2011 resulted in increased Energy Service expenses of $22,560. PSNH procures FTRs primarily to provide cost certainty and thus reduce risk, rather than to achieve savings. 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. Refer also to Staff-1, questions 13 and 14 in this docket for additional details regarding PSNH's FTR activities and settlement during 2011.

**Witness:** **Frederick White**
**Request from:** **Office of Consumer Advocate**

**Question:**
Reference Attachment FBW-2. Please provide an alternate version of this Attachment with "Merrimack and Schiller" and "Newington and Wyman" each separated into their own columns rather than in combined form as shown.

**Response:**
Please see the attached table.

**Peak**

| 2011 | Energy Requirement MWh | PSNH Resource Subtotal | IPPs | Buyout Contracts | Vermont Yankee | Hydro | Merrimack | Schiller | Newington | Wyman | Bilateral Purchases | ISO-NE Spot Purchases | Combustion Turbines |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Portion of Requirement Served by ... | | | | | | | | | | |
| Jan | 261,038 | 82% | 9% | 0% | 3% | 6% | 47% | 14% | 3% | 0% | 15% | 3% | 0% |
| Feb | 238,940 | 90% | 8% | 1% | 3% | 5% | 58% | 15% | 1% | 0% | 8% | 2% | 0% |
| Mar | 251,879 | 90% | 10% | 1% | 3% | 8% | 55% | 12% | 0% | 0% | 7% | 3% | 0% |
| Apr | 209,089 | 68% | 11% | 2% | 3% | 9% | 34% | 9% | 0% | 0% | 23% | 9% | 0% |
| May | 209,627 | 51% | 11% | 2% | 3% | 9% | 16% | 9% | 0% | 0% | 42% | 7% | 0% |
| Jun | 251,139 | 64% | 6% | 1% | 3% | 5% | 42% | 7% | 0% | 0% | 16% | 20% | 0% |
| Jul | 269,328 | 70% | 4% | 1% | 2% | 2% | 43% | 11% | 7% | 0% | 12% | 18% | 0% |
| Aug | 275,810 | 50% | 5% | 1% | 3% | 4% | 27% | 7% | 3% | 0% | 19% | 31% | 0% |
| Sep | 222,559 | 33% | 8% | 1% | 3% | 6% | 5% | 10% | 1% | 0% | 42% | 25% | 0% |
| Oct | 207,421 | 45% | 10% | 2% | 1% | 7% | 10% | 8% | 6% | 0% | 41% | 15% | 0% |
| Nov | 223,694 | 58% | 10% | 2% | 3% | 6% | 31% | 5% | 2% | 0% | 30% | 12% | 0% |
| Dec | 244,988 | 53% | 9% | 1% | 3% | 6% | 28% | 6% | 0% | 0% | 33% | 14% | 0% |
| Totals | 2,865,512 | 63% | 8% | 1% | 3% | 6% | 34% | 10% | 2% | 0% | 23% | 13% | 0% |

**Off-Peak**

| 2011 | Energy Requirement MWh | PSNH Resource Subtotal | IPPs | Buyout Contracts | Vermont Yankee | Hydro | Merrimack | Schiller | Newington | Wyman | Bilateral Purchases | ISO-NE Spot Purchases | Combustion Turbines |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Portion of Requirement Served by ... | | | | | | | | | | |
| Jan | 256,643 | 95% | 11% | 1% | 3% | 7% | 57% | 12% | 4% | 0% | 0% | 5% | 0.00% |
| Feb | 216,339 | 94% | 9% | 1% | 3% | 6% | 61% | 12% | 1% | 0% | 0% | 6% | 0.00% |
| Mar | 207,201 | 88% | 13% | 2% | 4% | 10% | 50% | 10% | 0% | 0% | 0% | 12% | 0.00% |
| Apr | 190,657 | 76% | 14% | 2% | 4% | 12% | 37% | 6% | 0% | 0% | 8% | 16% | 0.00% |
| May | 201,876 | 51% | 13% | 2% | 4% | 12% | 12% | 9% | 0% | 0% | 31% | 18% | 0.01% |
| Jun | 188,441 | 81% | 8% | 2% | 4% | 8% | 51% | 8% | 0% | 0% | 0% | 19% | 0.00% |
| Jul | 270,911 | 69% | 5% | 1% | 3% | 3% | 46% | 9% | 2% | 0% | 0% | 31% | 0.00% |
| Aug | 216,442 | 57% | 6% | 1% | 3% | 4% | 35% | 7% | 0% | 0% | 6% | 37% | 0.00% |
| Sep | 205,331 | 37% | 9% | 2% | 3% | 7% | 7% | 8% | 1% | 0% | 16% | 47% | 0.00% |
| Oct | 195,946 | 46% | 13% | 2% | 1% | 9% | 11% | 9% | 1% | 0% | 15% | 40% | 0.00% |
| Nov | 202,450 | 66% | 13% | 2% | 4% | 8% | 34% | 6% | 0% | 0% | 0% | 34% | 0.00% |
| Dec | 242,917 | 59% | 11% | 1% | 3% | 7% | 29% | 7% | 0% | 0% | 10% | 30% | 0.00% |
| Totals | 2,595,156 | 69% | 10% | 2% | 3% | 7% | 36% | 9% | 1% | 0% | 7% | 24% | 0.00% |

Note: "Buyout Contracts" refers to IPP replacement purchases (Bio Energy).
Note: "PSNH Resource Subtotal" is the sum of all columns except Bilateral and Spot Purchases.
Note: Lempster PPA is included in "IPPs".

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request OCA-01**
**Dated: 06/26/2012**
**Q-OCA-013**


**Witness:** **William H. Smagula**
**Request from:** **Office of Consumer Advocate**

## Question:
Reference testimony of William H. Smagula page 4 (Bates 000065) lines 4-7. Please discuss the circumstances related to Newington Station that resulted in burning oil in roughly 30% proportion to natural gas. Was the price of oil lower than natural gas making this an economic decision?

## Response:
Newington Station burned oil in 2011 for the following reasons:

1. The boiler's original design was based on burning residual fuel oil. This design results in some limitation of full gas firing, specifically in the unit's upper load range. Operation above 310 MW requires that fuel oil be utilized to protect certain components in the boiler from overheating, and a maximum of 200 MW of gas generation can be achieved when the unit is at full load with the balance of fuel input from oil.
2. Newington Station operated on oil to complete the summer and winter capability full load audits required by ISO-NE, operating above the 100% gas range.
3. The unit operated on oil when natural gas was unavailable.
4. The unit operated on oil when natural gas was more expensive.

The combination of the foregoing reasons resulted in 30% oil utilization. Item 2 above does not have the option of 100% natural gas through the full operating range of the unit. However, Newington has the flexibility of dual fuel operation and can utilize different fuel blends to maximize customer benefit. For example, in 2011 the winter capability audit was completed on January 24th while combusting 100% oil. During this audit natural gas pricing was approximately $20.00 per MMBtu making oil the low cost fuel for this audit. The summer capability audit was completed on August 17th using a blend of natural gas and oil to satisfy the full operating range of the unit across the audit period and operating day.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-003**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

**Question:**
What were the 2011 capacity factors for all of the generating facilities that PSNH owns? Please provide capacity factors for the same generating facilities for 2008, 2009 and 2010.

**Response:**
The table below shows capacity factors for units owned and operated by PSNH.

| Unit ID | 2011 Capacity Factor (%) | 2010 Capacity Factor (%) | 2009 Capacity Factor (%) | 2008 Capacity Factor (%) |
|---|---|---|---|---|
| MK1 | 57.9 | 67.8 | 84.1 | 79.8 |
| MK2 | 47.9 | 68.9 | 56.1 | 72.8 |
| NT1 | 3.6 | 6.4 | 5.2 | 3.3 |
| SR4 | 28.8 | 53.9 | 59.5 | 78.5 |
| SR5 | 78.3 | 84.1 | 79.6 | 79.8 |
| SR6 | 25.3 | 52.3 | 56.9 | 80.7 |
| Hydro | 60.5 | 54.7 | 68.6 | 68.7 |

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-007**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

**Question:**
Reference Mr. Smagula's prefiled testimony in this docket, pages 3 and 4, please define "availability".

**Response:**
Mr. Smagula was referring to the equivalent availability factor for the PSNH fossil fleet during the 30-highest priced days, reference PSNH response to TC-01, Q-TC-026 for definition of equivalent availability.

**Witness:** Frederick White
**Request from:** TransCanada

**Question:**
Reference Mr. White's prefiled testimony in this docket, page 3, lines 10-11. Please provide detail for 2011 for each of the generating facilities that PSNH owns as to when the decision was made because of the "relative economics of PSNH's generation versus purchase alternatives" to shut each such facility down or to not turn it on when it was otherwise available.

**Response:**
Ultimately, energy markets in ISO-NE are hourly markets, and each day represents a distinct "operating day." PSNH and all market participants offer their generating units into the ISO-NE energy market on a daily basis in accordance with a myriad of market rules. PSNH's bidding and scheduling function and generating units' control rooms interact with ISO-NE on daily and hourly bases. Additionally, internal multi-function operations planning discussions occur at least twice weekly, often daily during transient or extreme system conditions. Weekly and monthly planning dovetails with short term discussions and periodic longer term planning occurs including when prepared in conjunction with ES rate proposals.

**Witness:** **Frederick White**
**Request from:** **TransCanada**

## Question:

Reference Mr. White's prefiled testimony in this docket, page 3, lines 10-11. Please explain in detail the process that PSNH used to determine when it was appropriate to purchase power rather than to supply it from generation owned by PSNH. Please provide any and all documentation that PSNH has to explain or to guide the process for making such a decision. Please provide a list of the employee or employees who made these decisions.

## Response:

Operations planning and supplemental purchasing decisions are based on the relative economics of each course of action, and factors involved in the decision making process include price and load projections, unit operating and fuel procurement considerations, and the associated risks. The process is guided by internal regulated wholesale marketing policies, procedures, and guidance documents; primarily Wholesale Marketing Policy - PSNH Load Asset Management, RWM-1- Power Supply Planning and Development, RWM-2 - Portfolio Management, and Guidance for PSNH ES Rate Supplemental Energy Needs dated August 19, 2011. Redacted versions are attached. Employees involved include personnel from PSNH Generation, Wholesale Power, Fuel Purchasing and Supply, Power Supply Analysis, and Bidding and Scheduling; including over time: Gary Long, President - PSNH; John MacDonald, Vice-President Generation - PSNH; William Smagula, Director- PSNH Generation; Elizabeth Tillotson, Technical Business Manager Fossil/Hydro; Drew O'Keefe, Supervisor Engineering Services; Richard Despins, Donald Gray, & Harold Keyes, Station Managers; Jody Tenbrock, Manager Fuel Purchasing and Supply; James Shuckerow, Director Wholesale Power Contracts; David Errichetti, Manager Generation Resource Planning; Patrick Smith, Manager Wholesale Power Contracts; Frederick White, Supervisor Power Supply Analysis.

Northeast
Utilities System

# Wholesale Marketing Policy

# PSNH Load Asset Management

**Approved By:**

Gary A. Long
**President & Chief Operating Officer - PSNH**

**Effective Date:** November 10, 2011

**Revision: 3**

# 1 Overview

1.1 The Regulated Wholesale Marketing ("RWM" or also known as Wholesale Power Contracts) Department's Policies and Procedures (P&P) will ensure a level of oversight and control which is commensurate with the business undertakings and risks associated with a regulated electric utility company.

# 2 Departmental Policies and Procedures

2.1 RWM will maintain detailed and accessible procedures to control and manage the work process. The RWM Policies and Procedures (P&P) will be maintained as a controlled document. Each procedure will have a designated process owner who will be responsible for maintaining such procedure. Procedures can be incorporated by reference into the RWM P&P.

2.2 The Director – Wholesale Power Contracts will be responsible for obtaining approval for P&P. Policies will be approved by the PSNH President. Procedures will be approved by the Director – Wholesale Power Contracts.

2.3 RWM Procedures will include:

- Regulated Wholesale Marketing's Role in PSNH's Energy Service Associated with Power Supply Planning and Development (RWM-1)
  - Annual power supply portfolio planning process
- PSNH Portfolio Management (RWM-2)
  - Planning process for load obligation fulfillment.
  - Hedging, including Financial Transmission Rights (FTR)
  - Bidding and Scheduling of load/generation
- Contract Administration (RWM-3)
  - Details for the development, approval and administration of contracts with marketing and trading counterparties

- Transaction Execution, Confirmation and Reporting for Power Related Products (RWM-4)
  - Transaction execution
  - Deal capture, accounting designation and reporting
  - Controls, including independent confirmation
  - Exceptions
- Congestion Management (RWM-12)
- Forward Capacity Market (RWM-14)

# 3 Authorized Activities

3.1 RWM is authorized to conduct activities associated with power related products in support of PSNH generation and Energy Service ("ES") load obligation activities as well as Renewable Energy Certificate (REC) purchases and sales. The conduct and scope of these activities is limited to the ISO-NE power pool and adjoining power pools. Adjoining power pools include New York ISO, New Brunswick and Hydro-Quebec.

3.2 [redacted]

3.3 Power related products are defined as:

- Energy (Day Ahead spot market, Real Time spot market and bilateral contracts).
- Capacity (including products available bilaterally and through the ISO-NE administered Forward Capacity Market).
- Ancillary services, such as operating reserves, regulation and the forward reserve market.
- Structured products (ex. Financial Transmission Rights, Generation Outage Insurance, Put Options, Call Options, Transmission wheeling arrangements, etc.)

- Renewable Energy Certificates

# 4 Departmental Policies and Procedures

4.1 **Transactional limits** are based on PSNH power supply strategy (Annual, Monthly, Day to Day).

- Annual – An annual evaluation of power supply requirements will be performed as part of the PSNH Energy Service (ES) filing. Transactions associated with this annual review will require written authorization from the President – PSNH. These transactions will include energy, capacity and other power related products.
- Monthly – Transactions which were not addressed in the annual ES evaluation and which may be of duration [redacted] will require written authorization from the President- PSNH.
- Day to Day – Transactions of [redacted] will require authorization from Manager – Wholesale Power or designee, or the Director –Wholesale Power Contracts, or the President-PSNH. Manager – Wholesale Power is authorized to enter into transactions of this duration up to a dollar limit of [redacted] If the transaction value will exceed this limit, authorization is required from Director –Wholesale Power Contracts. Additionally, [redacted] must be approved by Director – Wholesale Power Contracts.
- Once authorization for the transaction(s) is received the Manager – Wholesale Power, or designee, will be responsible to ensure that transactions are executed in accordance with RWM P&P.

## 4.2 Volumetric Limits

4.2.1 Capacity – PSNH ES capacity needs are met thru owned generation resources and purchased from the ISO-NE. The ES costs associated with the provision of capacity are forecasted and incorporated into the ES rate filing approved by NH PUC. The ISO-NE has implemented a FERC approved Forward Capacity market where price is derived from an ISO-NE administered auction. [redacted] If RWM is unable to execute bilateral contracts on terms considered favorable to PSNH customers, the ISO-NE auctions will be utilized for the net ES requirement.

4.2.2 Energy – RWM will limit [redacted] risk for daily ES customer load, through bilateral contracts, generator availability / utilization or other means. [redacted] The limits will be calculated for each time period by netting together the load requirements for such period with the available generation, bilateral purchases and bilateral sales for the period. If these volumetric energy limits are exceeded, approval must be given by Director – Wholesale Power Contracts.

| Time Period | Volume Limit<br>% of total daily obligation for specific time period |
|---|---|
| [redacted] | [redacted] |

4.2.3 Resource to Load Congestion Cost – If applicable, the goal of RWM's congestion management for PSNH will be to limit congestion cost exposure from expected supply resource to ES load obligation by bidding in the ISO-NE Financial Transmission Rights (FTR) auction and/or bilateral purchases. [redacted] For the strategic processes to achieve the objective, refer to Procedure RWM-12. Volumetric Limits will be established [redacted] terms by the Director, Wholesale Power Contracts. The limits will be based on expected supply resources and system conditions. [redacted] FTR and bilateral purchases will be approved by the Director, Wholesale Power Contacts. [redacted] FTR purchases exceeding [redacted] and bilateral purchases exceeding [redacted] require approval from the President – PSNH. FTR and bilateral purchases for periods [redacted] require the President-PSNH approval.

4.2.4 Renewable Energy Certificates ("RECs") purchased for ES rate needs – Commencing with Calendar Year 2008, the state of New Hampshire has implemented a Renewable Portfolio Standard ("RPS") which requires that a portion of the power supply services provided to PSNH ES rate customers be derived from generation compliant with NH RPS. Compliance is exhibited annually through a filing to NHPUC and can be met with either NH compliant RECs or through an Alternate Compliance Payment ("ACP"). An ACP is provided in lieu of compliant RECs. RWM will coordinate REC procurement with PSNH in an attempt to reduce the ACP payments. The quantity of RECs procured annually will not exceed [redacted] for NH RPS compliance without prior approval from President-PSNH or designee.

## 5 Renewable Energy Certificate Sales

5.1 RWM is authorized to sell RECs derived from PSNH owned and operated generation, in particular, Northern Wood Power Project, generation entitlement contracts and IPPs. [redacted] The following process will be utilized for control of REC sales transactions:

5.1.1 Strategy: [redacted] the Manager – Wholesale Power, or designee, will meet with PSNH staff (including Director – Business Planning and Customer Support Services) to discuss [redacted] This strategy will be reviewed and approved by President – PSNH.

5.1.2 REC Sales Transactions: Once a marketing and pricing strategy has been approved Manager – Wholesale Power or designee will be responsible for the implementation of such in accordance with RWM P&P. [redacted]

5.1.3 Sales Contract Signatures: Forward Sales contracts will be signed by President – PSNH, V.P. Generation – PSNH, or designee. In addition, inventory Sales contracts can be signed by Director – Wholesale Power Contracts or designee.

## 6 Credit and Contract Requirements

6.1 RWM shall transact all business activities in accordance with:

- Contract requirements as detailed in the RWM "Contract Administration" procedure. (RWM-3).
- Counterpart creditworthiness and controls as detailed in the "Credit Risk Management" procedure (RWM-9).

## 7 Reporting

7.1 RWM will be responsible to provide accurate and timely reporting of all transaction information in accordance with approved RWM P&P. As a minimum, RWM will participate in the development and/or report the following:

[redacted]

- Year-to-date actual costs versus ES estimated costs, upon request of President – PSNH. This report will also include an assessment of expected ES power supply cost performance for the balance of year. The assessment is based on current market conditions and includes the effect of existing RWM transactions.

- A periodic report of bilateral and FTR transactions when requested by the President- PSNH.

7.2 Additional [redacted] is not necessary for the transactions associated with PSNH load asset management activities.

## 8 Systems

8.1 Information Technology (IT) systems will be controlled in accordance with Corporate IT standards.

8.2 RWM critical business processes will be designed such that security of data, disaster recovery and business continuity have been addressed.

## 9 Revision History

| Version Number | Date | Modified By | Revision Description |
|---|---|---|---|
| 0 | 08/24/2004 | P. Smith | First issuance. |
| 1 | 12/22/05 | P. Smith | Incorporated allowance for REC transactions. |
| 2 | 04/01/2010 | L. Harris<br>M. Paquette<br>P. Smith | Change Manager, Wholesale Marketing to Manager, Wholesale Power; Conforming changes |
| 3 | 11/10/2011 | P. Smith | Misc. conforming changes based on Wholesale Power review |

# BUSINESS PROCEDURE

| Northeast Utilities System | SUBJECT<br>REGULATED WHOLESALE MARKETING'S ROLE IN PSNH'S ENERGY SERVICE ASSOCIATED WITH POWER SUPPLY PLANNING AND DEVELOPMENT | | NAME & NUMBER<br>REGULATED WHOLESALE MARKETING PROCEDURE<br>RWM - 1 |
|---|---|---|---|
| DATE APPROVED<br>November 22, 2011 | DATE EFFECTIVE<br>October 1, 2004 | | PROCEDURE OWNER<br>Manager,<br>Generation Resource Planning |
| REVISION<br>2 | APPLICABLE TO<br>PSNH | | APPROVED BY<br>James R. Shuckerow<br>Director, Wholesale Power Contracts |

**PURPOSE**

This procedure documents Regulated Wholesale Marketing's role in PSNH's Energy Service ("ES") associated with the biannual review and development of the ES Rate and associated power supply planning.

**GENERAL INFORMATION**

PSNH's ES rates are based on a forecast of PSNH's actual costs incurred to serve load including both fixed and variable costs with IPPs valued at market rather than at rate order / contract prices. In setting the ES rate Wholesale Marketing is responsible for estimating the non-fixed cost portion of the actual costs expected to be incurred by PSNH in serving ES load (excluding NOx allowance costs).

**PROCEDURE**

This is a biannual process. The initial calculation is performed in late August, early September. The calculation is revised throughout the fall as additional information becomes available. The last revision is used to establish the ES Rate for at least the first six months of the ES Rate period (January through December of the following calendar year). This process is repeated over the months of April to June in order to permit the ES Rate to be reset in July, if necessary.

**Primary inputs needed for each ES Rate cycle:**

1. Forecasted hourly loads measured at the ISO-NE pool transmission facility (PTF) boundary. This load forecast will be provided by NUSCO Economic and Load Forecasting group and will be adjusted to take into account current and/or projected levels of customer migration.
2. List of generation resources owned or contracted to PSNH available to serve PSNH ES load.
3. Claimed capabilities of generation resources identified in item 2.
4. Heat rates for owned fossil steam generation resources.
5. Burner tip fuel prices for owned fossil steam generation resources (i.e., commodity, transportation, fuel adders, disposal costs, emission adders, etc.).
6. Target availability factors for owned fossil steam generation resources.

7. Planned annual maintenance schedules for owned generation

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resources including time stamps (year, month, day, hour ending) for first hour and last hour out of service.

8. Other owned generation information as appropriate such as hot and cold start up costs, minimum run times, minimum shutdown times, minimum output levels, allowable number of cold starts and hot starts per year, any operating restrictions due to permits or physical conditions, non-primary fuel costs at units.
9. Forecast purchases from resources contracted to PSNH including IPPs, Vermont Yankee and system purchases which were made to replace IPP purchase power agreements.
10. Forecast hydro generation based on most recently available twenty years.
11. Bilateral purchases and sales made to serve load and / or manage exposure to spot market.
12. Historical hourly energy price relationships between various off peak subset periods.
13. Historical hourly energy price patterns.
14. Historical loss and congestion prices between power supply source locations and the New Hampshire load zone.
15. PSNH's capacity requirements based on most recently available Installed Capacity Requirement values,NEPOOL load forecast and the Forward Capacity Market clearing price
16. Forward market prices for energy.
17. PSNH owned or contracted for resources which generate Renewable Energy Certificates ("RECs") that fulfill the NH Renewable Portfolio Standards ("RPS").
18. Forward market price for NH qualified RECs.
19. ISO and NEPOOL expenses and revenues associated administering the energy markets including VAR expense, Black Start expense, Schedule 2 and 3 ISO expense, NOATT expense, NEPOOL expense, Black Start revenues, VAR revenues, etc. that are allocated to energy load.
20. Costs associated with non-energy, non-capacity ISO-NE power markets such as operating reserves, regulation and the Forward Reserve Market.

**Modeling:**

The above inputs are then used to develop four groupings of costs:

1. Energy
   - Owned generation, the Vermont Yankee purchase, known bilateral purchases / sales and IPPs are utilized.
   - Owned generation is modeled and dispatched at cost and in an economic manner, relative to forward market prices. The dispatch model uses appropriate inputs such as heat rates, burner tip fuel prices and start up charges.
   - Vermont Yankee is included at its contract rates.
   - IPP generation is priced based on forward energy market prices.
   - Any bilateral purchases / sales are priced based on actual contract terms.
   - Any ES power supply shortfall or excess is assumed to be purchased or sold, based on forward market prices, at the applicable modeled hourly energy clearing price
   - Congestion and loss costs are calculated based on historical patterns adjusted by forward market energy prices.

2. Capacity
   - Owned generation, Vermont Yankee and IPP capability converted to equivalent unforced capacity plus any HQ ICC credits are used to meet forecast obligation. Any shortfalls are met with either committed purchases cost at contract term or bought at the applicable Forward Capacity Market clearing prices.

3. Ancillary and ISO/NEPOOL Expenses
   - Ancillary costs are made up of operating reserve costs, regulation costs, forward reserve market charges and any other markets, existing or new, that ISO-NE may require. These are developed based on historical prices, recent auction results, forward prices to the extent they influence costs and predictions (in the case of markets not yet implemented).

   - ISO / NEPOOL expenses are anything on the ISO bills not charged to transmission and not covered by energy, capacity or ancillaries.

4. RPS Expenses
   - Owned and contracted for NH RPS resources are used to meet the forecast obligation. Any surplus / shortfall is assumed to be purchased or sold based on forward market prices or, if a market deficiency of RECs is anticipated at the applicable Alternate Compliance Payment rate.

**Output:**

The costs developed in the model are summarized and passed on to Revenue Regulation and Load Resources for inclusion in their development of the ES Rate. The information is transmitted as a single tab spreadsheet.

## REVISION HISTORY

| Revision Number | Date | Modified By | Revision Description |
|---|---|---|---|
| 1.0 | 6/1/08 | P. Smith | Incorporates change in designation of Full Requirements to Energy Service |
| 2.0 | 11/22/11 | P. Smith | Misc. changes due to Wholesale Power review |
| 3.0 | | | |

## BUSINESS PROCEDURE

| Northeast Utilities System | SUBJECT<br>PORTFOLIO MANAGEMENT | NAME & NUMBER<br>REGULATED WHOLESALE MARKETING PROCEDURE<br>RWM - 2 |
|---|---|---|
| DATE APPROVED<br>November 22, 2011 | DATE EFFECTIVE<br>October 1, 2004 | PROCEDURE OWNER<br>Manager,<br>Wholesale Power |
| REVISION<br>3 | APPLICABLE TO<br>PSNH | APPROVED BY<br>James R. Shuckerow<br>Director, Wholesale Power Contracts |

**PURPOSE**

This document defines Regulated Wholesale Marketing's ("RWM") procedures regarding the PSNH Load Management activities including:

- Planning process for load obligation fulfillment
- Hedging
- Bidding and Scheduling for PSNH Generation and Load Obligations

**GENERAL INFORMATION**

RWM, along with various PSNH functional groups, has an important role in the PSNH Energy Service ("ES") Rate development and management process. The Energy Service provides generation service to the PSNH customers who have not chosen a competitive retail supplier.

**PROCEDURE**

**Annual ES Strategy**

Procedure RWM-1 entitled " Regulated Wholesale Marketing's Role in PSNH's Energy Service Associated with Power Supply Planning and Development," details the process of developing the annual PSNH ES rate. At an appropriate point in the development of the ES rate, a hedging strategy team will be assembled to explore options available to achieve greater price certainty in the area of power procurement. The strategy team must coordinate with PSNH Generation to ensure that the hedge plan incorporates the appropriate level of reliance on fossil-hydro generation. This team will develop a recommendation for power hedging activity to be utilized in the next ES rate year.

The recommended hedge plan should be discussed with PSNH Regulatory and PSNH Generation departments. Final submittal of the plan to President – PSNH is required to obtain authorization. Once authorization is received all transactions will be performed in accordance with applicable RWM Policies and Procedures.

**ES Strategy Assessment**

A periodic meeting to Review ES Performance vs Forecast will be conducted. Manager – Wholesale Power and Manager – Generation Resource Planning or designees will be responsible to facilitate the meetings. These meetings are designed to be at "the worker level" and to dig deeper into detailed variances that are driving performance. A brief summary of the results, as well as any variances of particular significance, will be forwarded to senior management. These meetings will also address expense control issues impacting subsequent months of the rate period (e.g. fuel inventory, bilateral purchase strategy, Newington utilization).

Additionally, it is recognized that market conditions and / or ES customer migration trends may change such that modifications to the annual hedge plan may be warranted. Any modifications to the annual hedging strategy (including energy purchases or sales) will be submitted to the appropriate entity for authorization prior to execution. Authorization and authorization limits will be in accordance with RWM Policies and Procedures.

**Daily Strategy**

From 6:00 AM until 9:00 AM the day prior, bidding and scheduling personnel will run the respective models to forecast ES load. Additionally, B/S personnel will contact the generating units to determine operating status.

By 9:00 AM the business day prior, bidding and scheduling personnel will meet with the Manager – Wholesale Power ("Mgr – WP") or designee to discuss the day-ahead bidding strategy. B/S will assess the portfolio position by utilizing the forecasted load, available generation and known bilateral purchases or sales. [redacted]

The bid strategy will be in accordance with the requirements of the PSNH Load Asset Management Policy. In order to develop a strategy, the Bidding Supervisor, or designee, will need to assimilate all appropriate and necessary information regarding load forecasts, estimated MCP's, competitive intelligence, and generating unit characteristics. The B/S personnel will meet on a regular basis with the Manager – Wholesale Power ("Mgr – WP") or designee to communicate market activity, fuel purchases, overnight activity, etc. B/S will contact the plants to determine operating status, as well as run the multiple regression/neural network models to forecast loads. Once all of this data has been gathered, the Bidding Supervisor, or designee, will evaluate the information and determine the bid strategy. Generation and load bid will be submitted in accordance with the timing requirements of the ISO-NE market rules.

The Bidding and Scheduling Log will document the current day's [redacted] Compliance with the volumetric energy limits identified in the PSNH Load Asset Management Policy will be noted and documented. If compliance will not be achieved Mgr – WP will be informed and additional bilateral purchases will be made. Items of significance will also be documented in the Log.

By 5:00 PM each day or within 1 hour of receiving information from ISO-NE, B/S will retrieve from ISO-NE and e-mail to each generating unit their day-ahead commitment for generation for the next day.

**Energy Sales:**

As a result of the periodic review of ES load needs and anticipated economic PSNH generation it may be determined that some energy resources will not be required to meet ES customer needs. In this event the appropriateness of a sale into the bilateral energy market will be considered. Such sale opportunity will consider risks associated with customer load (weather driven demand and customer ingress/egress) as well as any unplanned generation resource loss. Bilateral sales recommendations will be submitted to the appropriate entity for authorization prior to execution.

**Contract Scheduling:**

Contracts which require physical delivery (Energy, Capacity) will be scheduled in the appropriate Independent System Operator ("ISO") market system. These schedules must be submitted by one party (typically the seller) and approved by the other (typically the buyer). Mgr – WP or designee is responsible to schedule and confirm physical deliveries in the market system in accordance with the timing requirements of the applicable market rules.

**Financial Transmission Rights**

RWM will try to limit congestion cost exposure from expected generation resource to load obligation by bidding in the ISO-NE Financial Transmission Rights (FTR) auction and/or bilateral purchases supplied at the New Hampshire load zone. Refer to Regulated Wholesale Marketing Procedure RWM-4 and RWM-12 for additional information

## REVISION HISTORY

| Revision Number | Date | Modified By | Revision Description |
|---|---|---|---|
| 1.0 | 6/1/08 | P. Smith<br>M. Paquette | Incorporates change in designation of Full Requirements to Energy Service; clarified FTR information by referencing Procedures RWM-4 and RWM-12 |
| 2.0 | 11/1/09 | L. Harris<br>M. Paquette | Update Procedure Owner to Manager, Wholesale Power; TS/DS updated to ES |
| 3.0 | 11/22/11 | P. Smith | Misc. editorial changes and added guidance on energy sales. |

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Data Request TC-01
Dated: 6/26/12
Q-TC-010
Attachment

August 19, 2011

Preamble: This guidance document addresses settlement agreement recommendations reached in Docket DE 10-121, dated January 11, 2011, page 3, Section III.B.1, regarding supplemental purchases and sales; and per discussions with NH PUC Staff's consultant on July 28, 2011 augments write-ups prepared in response to DE 11-094, Staff-1, Questions 5, 6, 7, & 9.

Guidance for PSNH ES Rate Supplemental Energy Needs

Beginning with commencement of the development of the ES rate and thru September of the ES rate year - PSNH to perform on a quarterly basis an analysis of loads based on the latest actual load data available and the current PSNH load forecast.

PSNH to review quarterly in order to determine if there is a need for supplemental energy purchases or sales. This review will take into account the economic utilization of owned generation, existing bilaterals, and IPPs in determining the ES energy portfolio net position (the Supplemental Needs). Purchases and/or sales recommendations will be developed based on the following:

As part of PSNH ES Rate Hedge Plan (Prior to Rate Setting):

Summer / Winter supplemental purchases should be made to meet [redacted] of Supplemental Needs. However, if supplemental needs are [redacted] or less this minimal exposure may remain un-hedged. If it is forecast that existing purchases and economic generation will meet [redacted] of needs, PSNH will attempt to sell any excess to reduce supply to [redacted] coverage of load. If the excess is within [redacted] of needs this minimal exposure may remain. However, PSNH will not [redacted].

Spring / Fall supplemental purchases should be made to meet [redacted] of Supplemental Needs. However, if supplemental needs are [redacted] or less this minimal exposure may remain un-hedged. If it is forecast that existing purchases and economic generation will meet [redacted] of needs, PSNH will attempt to sell any excess to reduce supply to [redacted] coverage of load. If the excess is within [redacted] of needs this minimal exposure may remain. However, PSNH will not [redacted].

During ES Rate Year (Quarterly Review):

If it is forecast that existing purchases and economic generation will meet [redacted] of needs, PSNH will attempt to sell any excess so as to maintain [redacted] coverage of load. If the excess is within [redacted] of needs this minimal exposure may remain. However, PSNH will not [redacted].

During ES Rate Year (Short Term – One Month or Less):

If during the PSNH weekly assessment of ES load needs and generation resources it is determined that a condition of oversupply [redacted] will occur due to owned generation and supplemental energy purchases and such condition is reasonably expected to be of a [redacted] duration, PSNH will evaluate market opportunities to 1) reduce generation output (if economically viable) and /or 2) sell supplemental energy. In this event of a sale into the bilateral energy market, such sale opportunity will consider risks associated with customer load (weather driven demand) as well as any potential for an unplanned generation resource loss.

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**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-011**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **TransCanada**

**Question:**
When did PSNH first begin to evaluate the economics of its generation versus purchase alternatives ?

**Response:**

PSNH has been evaluating the economics of its generation versus purchase alternatives since at least the mid-1980s. This activity continued after the merger with NU and continues to this day.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-012**
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**Witness:** **Frederick White**
**Request from:** **TransCanada**

**Question:**
Reference Mr. Baumann's prefiled testimony in this docket, page 6, lines 1-2, please provide what percentage of PSNH's energy needs that PSNH's owned generation provided during 2008, 2009 and 2010.

**Response:**
From Mr. Baumann's pre-filed testimonies in dockets DE 09-091, DE 10-121, and DE 11-094; the figures for 2008, 2009, & 2010 are 54%, 56%, & 64%, respectively.

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Data Request TC-01
Dated: 06/26/2012
Q-TC-013
Page 1 of 1

**Witness:** Frederick White
**Request from:** TransCanada

## Question:

Please provide the total MWh that PSNH provided from PSNH owned generation during 2008, 2009, 2010 and 2011.

## Response:

The MWh figures equivalent to the percentages provided in Q-TC-012 in this docket (plus the 2011 figure) are:

| | MWh |
|---|---|
| 2008 | 4,346,340 |
| 2009 | 3,710,255 |
| 2010 | 3,730,298 |
| 2011 | 2,862,519 |

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**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-014**
**Page 1 of 1**

**Witness:** **Robert A. Baumann, Frederick White**
**Request from:** **TransCanada**

## Question:
Reference Attachment RAB-2 to Mr. Baumann's prefiled testimony in this docket, please explain in detail the process PSNH used to come up with this chart, and in particular please explain in detail how the replacement power cost figures were arrived at.

## Response:
PSNH provides outage reports for all unscheduled outages in excess of two days at either Newington Station or at the two units at Merrimack Station, and in excess of four days at the three units at Schiller Station and at Wyman Unit 4. Mr. William H. Smagula provides Outage Reports for these outages and summarizes each outage in his testimony on pages 6-9 [Bates 000067-000070].

The replacement power costs were calculated hourly. For each hour, all supply resources (owned units, IPPs, bilateral purchases and ISO-NE spot purchases) were ordered based on their estimated dispatch prices from lowest cost to highest cost. The hour's actual energy expense was estimated by adding up the expenses of the resources whose output added up to the load. In a subsequent analysis, the unit out of service was placed back into the supply stack at an assumed availability and at the appropriate place in the dispatch order. The hour's energy expense was then recalculated as if the unit had been available. The replacement power cost was the difference in the cost to serve load between the two analyses.

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**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-016**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **TransCanada**

**Question:**
Reference Attachment FBW-2 to Mr. White's prefiled testimony in this docket. Please provide the same information in the same format for 2008, 2009 and 2010.

**Response:**
The requested information for 2008, 2009, and 2010 is available in dockets DE 09-091, DE 10-121, and DE 11-094, as Attachments RCL-2, DAE-2 and FBW-2, respectively.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-017**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **TransCanada**

**Question:**
Reference Attachment FBW-3 to Mr. White's prefiled testimony in this docket. Please provide the same information in the same format for 2008, 2009 and 2010.

**Response:**
The requested information for 2008, 2009, and 2010 is available in dockets DE 09-091, DE 10-121, and DE 11-094, as Attachments RCL-3, Supplemental DAE-3, and FBW-3 - Corrected, respectively.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-018**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **TransCanada**

## Question:

Please reconcile and explain Mr. Baumann's prefiled testimony in this docket, page 6, lines 1-2 to the effect that PSNH owned generation provided 52% of PSNH's energy needs with Mr. White's prefiled testimony in this docket, page 2 line 33 to page 3 line 1 to the effect that 63% of peak energy requirements and 69% of off-peak energy requirements were met with PSNH's generation resources.

## Response:

The figures from Mr. White's testimony include, in addition to PSNH owned generation, energy from generation resources not owned by PSNH, such as IPPs, buyout contracts, Vermont Yankee, and Lempster Wind.

Public Service Company of New Hampshire
Docket No. DE 12-116

Data Request TC-01
Dated: 06/26/2012
Q-TC-019
Page 1 of 1

**Witness:** Frederick White
**Request from:** TransCanada

**Question:**
Reference Mr. White's prefiled testimony in this docket, page 3, line 15, what percentage of the fixed price contracts were purchased prior to 2011 and when were they purchased ?

**Response:**
Of the 733 GWh of fixed price peak energy purchases approximately 56% were purchased prior to 2011, via two separate transactions in September and October, 2008. Of the 185 GWh of fixed price off-peak energy purchases none were purchased prior to 2011.

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**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-020**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **TransCanada**

**Question:**
Reference Mr. White's prefiled testimony in this docket, page 3, line 33, what is the subtotal of $103.9 million that is attributable to contracts purchased prior to 2011?

**Response:**
The subtotal attributable to contracts purchased prior to 2011 is $35.3 million.

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**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-021**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **TransCanada**

## Question:

Reference Mr. White's prefiled testimony in this docket, page 4, line 24, please explain in detail how during periods of low natural gas prices PSNH's resources provide insurance against price increases.

## Response:

Energy prices are not invariably low during periods of generally low natural gas prices. Prices may increase if, due to other factors such as extreme temperatures and high loads, unit availabilities, or forecast errors; the marginal resource(s) in the ISO-NE region is a less efficient gas-fired unit or is a unit fired by something other than gas. For instance, recently over June 20-22 prices in New Hampshire averaged $87/MWh, well above prices which might be expected during a "period of low natural gas prices." PSNH's units provided a hedge against the significant increase in market prices during that period. Also, low commodity prices do not invariably translate into low generation burner tip prices. Prices for gas delivered to New England may increase due to natural gas infrastructure problems such as when natural gas pipelines perform maintenance or are shut down/limited due to storms and other exigencies. During any of these periods of price increases PSNH's resources are available for customers as physical insurance against high prices.

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**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-022**


**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

## Question:

Reference Mr. Smagula's prefiled testimony in this docket, page 3, lines 4-6, what were the fleet's capacity factors during this same period of time ?

## Response:

PSNH does not calculate unit or fleet specific performance statistics on a daily basis, these types of statistics are completed monthly and submitted to the North American Electric Reliability Corporation and ISO-NE as required. The fleet availability is calculated as a unique metric to ensure the units are in a state of readiness during the 30-highest priced days and able to limit customer exposure to high rates. As an indicator to the status of each unit the following table is provided. Note: The check mark indicates the unit was operating.

Operating Status of PSNH Units on the 30 Highest Priced Days of 2011

| Date | MK 1 | MK2 | NT | SR4 | SR5 | SR6 |
|---|---|---|---|---|---|---|
| 01/12/2011 | √ | √ | Unit was Available | √ | √ | √ |
| 01/13/2011 | √ | √ | Unit was Available | √ | √ | √ |
| 01/14/2011 | √ | √ | Unit was Available | √ | √ | √ |
| 01/17/2011 | √ | √ | Unit was Available | √ | √ | √ |
| 01/18/2011 | √ | √ | Unit was Available | √ | √ | √ |
| 01/20/2011 | √ | √ | Unit was Available | √ | √ | √ |
| 01/21/2011 | √ | √ | √ | √ | √ | √ |
| 01/22/2011 | √ | √ | √ | √ | √ | √ |
| 01/23/2011 | √ | √ | √ | √ | √ | √ |
| 01/24/2011 | √ | √ | √ | √ | √ | √ |
| 01/25/2011 | √ | √ | √ | √ | √ | √ |
| 01/27/2011 | √ | Forced Outage (OR-2) | Unit was Available | √ | √ | √ |
| 01/28/2011 | √ | Forced Outage (OR-2) | √ | √ | √ | √ |
| 01/29/2011 | √ | Forced Outage (OR-2) | √ | √ | √ | √ |
| 01/30/2011 | √ | √ | √ | √ | √ | √ |
| 01/31/2011 | √ | √ | √ | √ | √ | √ |
| 02/02/2011 | √ | √ | √ | √ | √ | √ |
| 02/03/2011 | √ | √ | Unit was Available | √ | √ | √ |
| | | | | | | |
| 02/09/2011 | √ | √ | Unit was Available | √ | √ | √ |
| 02/10/2011 | √ | √ | Unit was Available | √ | √ | √ |
| 02/23/2011 | √ | √ | √ | √ | √ | √ |
| 02/24/2011 | √ | √ | Unit was Available | √ | √ | √ |
| 03/03/2011 | √ | √ | Unit was Available | √ | √ | √ |
| 06/09/2011 | √ | √ | √ | √ | √ | √ |
| 07/12/2011 | √ | √ | √ | √ | √ | √ |
| 07/18/2011 | √ | √ | √ | √ | √ | √ |
| 07/20/2011 | √ | √ | √ | √ | √ | √ |
| 07/21/2011 | √ | √ | √ | √ | √ | √ |
| 07/22/2011 | √ | √ | √ | √ | √ | √ |
| 07/23/2011 | √ | √ | √ | √ | √ | √ |

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-023**


**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

**Question:**
Reference Mr. Smagula's prefiled testimony in this docket, page 3, lines 13-14, what were Unit 1 and Unit 2's annual capacity factors in 2011 ?

**Response:**
Reference PSNH response to Q-TC-003

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-024**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

**Question:**
Reference Mr. Smagula's prefiled testimony in this docket, page 3, lines 24-25, what was Schiller Station's Unit 5 capacity factor during this same period of time (178 days following its scheduled overhaul)?

**Response:**
Schiller Unit 5 is a base load unit that operates when the unit is available; therefore the capacity factor for this period would mirror the equivalent availability factor of 99.7%. Note that PSNH does not calculate unit or fleet specific performance statistics on a daily basis, these types of statistics are completed monthly and submitted to the North American Electric Reliability Corporation and ISO-NE as required.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-026**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

## Question:

Reference Mr. Smagula's prefiled testimony in this docket, page 4, lines 6-7, please explain in detail what is meant by a 93.6% equivalent availability ?

## Response:

Newington Station's equivalent availability for 2011 was 93.6%. The term equivalent availability is an industry standardized metric, and is used to represent the portion of hours that a unit is available to be dispatched at full capacity. Equivalent availability is recognized by the North American Electric Reliability Corporation (NERC) and other regional entities such as ISO-NE. The NERC approved equation to calculate the Equivalent Availability Factor is:

EAF = [(Available Hours – Equivalent Unit Derated Hours) * 100] ÷ Period Hours.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-027**
**Page 1 of 1**

**Witness:** **William H. Smagula, Frederick White**
**Request from:** **TransCanada**

**Question:**
When generation owned by PSNH is not run due to the relative economics of PSNH's generation versus purchase alternatives is that considered to be a scheduled or an unscheduled outage ? Please explain your response in detail.

**Response:**

It is neither a scheduled nor unscheduled outage. The unit remains available for ISO-NE dispatch.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-028**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

## Question:

Reference Attachment WHS-3, bates page 121, further reference the Merrimack Unit 1 Historic Performance Data chart, please explain in detail what PSNH considers to be the reason that this Unit's capacity factor declined so significantly in 2010 and 2011 compared with prior years.

## Response:

WHS 3 "Merrimack Unit 1 Historic Performance Data" shows the annualized capacity factor from the period of 1993 to 2011. While capacity factors always fluctuate year-to-year based on the cyclic nature of planned outages and any forced outages, 2011's lower capacity factor at Merrimack 1 can be attributed to the following:

1) Historically low natural gas prices and,
2) Reduced electricity demand caused by the economic downturn.

**Witness:** William H. Smagula
**Request from:** TransCanada

## Question:
Reference Attachment WHS-3, bates page 121, reference the Merrimack Unit 2 Historic Performance Data chart, please explain in detail what PSNH considers to be the reason that this Unit's capacity factor declined so significantly in 2011 compared with prior years.

## Response:
WHS 3 "Merrimack Unit 2 Historic Performance Data" shows the annualized capacity factor from the period of 1993 to 2011. While capacity factors always fluctuate year-to-year based on the cyclic nature of planned outages and any forced outages, 2011's lower capacity factor at Merrimack 2 can be attributed to the following:

1) Historically low natural gas prices and,
2) Reduced electricity demand caused by the economic downturn.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-030**


**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

## Question:

Reference Attachment WHS-3, bates page 121, reference the Newington Unit 1 Historic Performance Data chart, please explain in detail what PSNH considers to be the reason that this Unit's heat rate increased so significantly in 2010 and 2011 compared with prior years.

## Response:

WHS 3 "Newington Unit 1 Historic Performance Data" shows the annualized heat rate from the period of 1993 to 2011. Heat rate is a function of heat input and generation. Because NT1 is a dual fuel unit, heat rate will vary depending on the fuel being combusted, the unit's operating load, and the number of startups and shutdowns.

Heat rate, as presented in this annual review and in this response, is an annualized value. It is not the value that is more commonly viewed as the specific measurement of a unit at optimum, full-load conditions. Thus, if the question is based on rationalizing full-load versus annual heat-rate, there is no comparison.

Still, in 2009, the NT1 heat rate was consistent with 2001, 2002, and 2006 when in each year the natural gas usage was similar in percentage ranging from 9.5% to 22% of total annual heat input. In contrast, in 2010 and 2011, NT1's heat rate was comparatively higher for the following reasons:

1) Natural gas contributed to approximately 70% of total annual heat input;
2) The number of total unit startups in 2011 was 53;
3) The unit startup process was altered in 2010 which allowed the unit start-up to occur exclusively combusting gas; and
4) In addition in recent years NT1 has been dispatched by the ISO NE to maintain energy reserve with an associated dispatch at approximately 100 MW. This low load operation has a higher heat rate than full load operation.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-031**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

**Question:**
Reference Attachment WHS-3, bates page 122, reference the Schiller Unit 4 Historic Performance Data chart, please explain in detail what PSNH considers to be the reason that this Unit's capacity factor declined so significantly in 2011 compared with prior years.

**Response:**
WHS 3 "Schiller Unit 4 Historic Performance Data" shows the annualized capacity factor from the period of 1993 to 2011. While capacity factors always fluctuate year-to-year based on the cyclic nature of planned outages and any forced outages, 2011's lower capacity factor at Schiller 4 can be attributed to the following:

1) Historically low natural gas prices and,
2) Reduced electricity demand caused by the economic downturn.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-032**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

## Question:

Reference Attachment WHS-3, bates page 122, reference the Schiller Unit 6 Historic Performance Data chart, please explain in detail what PSNH considers to be the reason that this Unit's capacity factor declined so significantly in 2011 compared with prior years.

## Response:

WHS 3 "Schiller Unit 6 Historic Performance Data" shows the annualized capacity factor from the period of 1993 to 2011. While capacity factors always fluctuate year-to-year based on the cyclic nature of planned outages and any forced outages, 2011's lower capacity factor at Schiller 6 can be attributed to the following:

1) Historically low natural gas prices and,
2) Reduced electricity demand caused by the economic downturn.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-033**


**Witness:** **Frederick White**
**Request from:** **TransCanada**

## Question:

Reference Mr. White's prefiled testimony in this docket, page 3, the Q & A that begins at line 4 and ends at line 11. In a similar Q & A in his prefiled testimony in DE 11-094 Mr. White included the following as part of his response: "PSNH's supplemental purchase requirement is heavily influenced by the economics of Newington. When Newington's fuel expense is lower than the cost of purchasing power, the unit can be dispatched and PSNH's supplemental need is significantly reduced. Forced and planned outages of PSNH's generating units also increase the need for supplemental purchases." Please explain in detail why this was part of the response to the same question in DE 11-094 but is no longer part of the response in DE 12-116.

## Response:

The ideas addressed by the deleted sentences were deemed adequately addressed by the remaining portions of the response; i.e. - "the relative economics of PSNH's generation versus purchase alternatives", and "depending on the availability of PSNH's resources", address more succinctly the same discussion. Additionally, it was a somewhat narrow view to mention only Newington when the ideas in general apply, and always have, for all PSNH energy resources.

Public Service Company of New Hampshire
Docket No. DE 12-116

Data Request TC-01
Dated: 06/26/2012
Q-TC-034
Page 1 of 1

**Witness:** William H. Smagula, Frederick White
**Request from:** TransCanada

## Question:

With respect to Newington operation on oil in 2011, what was the numerical value of the mark-up above inventory cost identified by Mr. Smagula in his testimony in DE 10-261 where he stated: "And we mark the oil price up so that our customers don't just get reimbursed for the cost of the fuel, but in fact make a small margin." (Transcript, Day 3 PM, page 133, lines 21-24).

## Response:

The numerical value of the mark-up above inventory cost is the margin that is added to the dispatch cost when a unit is dispatched to serve the NE-Pool and not PSNH customer load. This margin varies depending on the circumstances but is designed to offset maintenance costs as well as the projected replacement oil cost.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-035**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

**Question:**
Please describe the logistics necessary to make sales of residual oil from Newington inventory.

**Response:**
In 2012, PSNH executed two sales of residual oil from the Newington inventory, the process to complete these sales was a multi-phase effort that involved many stakeholders.

Feasibility Determination - Determine the feasibility of conducting a fuel oil transfer from the Newington inventory to a vessel at the PSNH dock. PSNH initiated an engineering study of the existing system which was completed by an outside engineering firm experienced with piping systems and fuel oil transfer. The intent of this study was to determine if the existing fuel oil transfer system was capable of completing such an operation and if any modifications were necessary. It was ultimately determined that a fuel oil transfer from the Newington inventory could be completed safely and with no impact to the environment. The final engineering report provided by this engineering firm did recommend, as a precautionary measure, that an upgraded check valve be located on the dock at the inlet to the oil transfer hose manifold.

Engineering, Procurement and Installation - Procure and install the new check valve recommended by the engineering firm. In addition to the recommendation for the upgraded check valve provided by the engineering firm, PSNH opted to use a dedicated and trained crew of employees to execute the oil transfer procedure and install additional control measures which included strategically located emergency stop buttons to shut down the oil transfer pumps. These stop buttons were installed on the dock so in the event of a malfunction, the oil transfer pumps could be shut down immediately.

Update and Approval of Procedures - Develop a fuel oil transfer procedure which was completed by PSNH in collaboration with a Person In Charge (PIC) certified marine service consultant specializing in fuel oil transfer. The procedure was then submitted to the US Coast Guard (USCG) for approval. In addition to the fuel oil transfer procedure, the USCG required the Terminal Operators Manual be modified to reflect this type of operation. The updated manual was also submitted to the US EPA as required under the emergency response Integrated Contingency Plan (ICP) for approval. Upon approval of the updated plans and procedures the fuel oil transfer could occur.

Execution of Off-loading - Implementation of oil off-loading to an empty vessel which included proper execution of the USCG approved fuel oil transfer procedure.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-01**
**Dated: 06/26/2012**
**Q-TC-037**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

**Question:**
Was any residual oil burned at Newington in 2011 for testing purposes? If so, please provide dates of such testing and the reason for it.

**Response:**
Yes. See the response to OCA-01, Q-OCA-013 pertaining to the combustion of residual oil at Newington. In 2011, Newington completed two ISO - NE audits that required the use of residual oil. On January 24, 2011,Newington completed the winter claimed capability audit and on August 17, 2011 the summer claimed capability audit.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-001**


**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Baumann testimony, RAB-2 (Bates 11), For the planned outages listed on page 10 of the Smagula testimony (Bates 71), please supply the replacement power costs calculated in the same manner as the response to Staff set 1, question 1.

**Response:**
See attached file.

**Merrimack 1**

| Date | Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|---|
| 04/12/2011 | 5,218 | 25,039 | 0 | 440 | (20,261) |
| 04/13/2011 | 26,274 | 18,216 | 0 | 14,810 | (6,752) |
| 04/14/2011 | 23,522 | 32,133 | 0 | 8,739 | (17,350) |
| 04/15/2011 | 26,671 | 28,264 | 0 | 11,252 | (12,846) |
| 04/16/2011 | 7,907 | 70,661 | 0 | 1,820 | (64,574) |
| 04/17/2011 | 3,914 | 65,323 | 0 | 785 | (62,194) |
| 04/18/2011 | 15,470 | 65,772 | 0 | 853 | (51,156) |
| 04/19/2011 | 12,906 | 76,460 | 0 | 445 | (63,999) |
| 04/20/2011 | 15,846 | 82,445 | 0 | 554 | (67,153) |
| 04/21/2011 | 13,795 | 0 | 22,744 | 4,238 | (13,187) |
| 04/22/2011 | 13,015 | 0 | 13,472 | 4,895 | (5,353) |
| 04/23/2011 | 12,700 | 0 | 66,332 | 380 | (54,012) |
| 04/24/2011 | 13,879 | 0 | 42,521 | 810 | (29,452) |
| 04/25/2011 | 15,401 | 607 | 19,042 | 5,413 | (9,660) |
| 04/26/2011 | 17,862 | 415 | 3,914 | 13,543 | (10) |
| 04/27/2011 | 17,296 | 0 | 2,455 | 14,847 | (6) |
| 04/28/2011 | 22,807 | 0 | 5,453 | 18,043 | (688) |
| 04/29/2011 | 15,135 | 79,422 | 23,977 | 0 | (88,265) |
| 04/30/2011 | 11,377 | 103,543 | 0 | 0 | (92,165) |
| 05/01/2011 | 31,116 | 49,251 | 0 | 6,720 | (24,855) |
| 05/02/2011 | 41,584 | 60,351 | 0 | 6,144 | (24,910) |
| 05/03/2011 | 41,761 | 59,522 | 0 | 7,416 | (25,177) |
| 05/04/2011 | 41,329 | 78,955 | 0 | 6,116 | (43,743) |
| 05/05/2011 | 31,514 | 64,167 | 0 | 2,993 | (35,646) |
| 05/06/2011 | 32,839 | 54,125 | 0 | 4,512 | (25,797) |
| 05/07/2011 | 15,470 | 85,906 | 0 | 68 | (70,504) |
| 05/08/2011 | 8,914 | 83,941 | 0 | 0 | (75,026) |
| 05/09/2011 | 3,541 | 23,212 | 0 | 721 | (20,392) |
| 05/10/2011 | 423 | 0 | 0 | 423 | 0 |
| 05/11/2011 | 309 | 0 | 0 | 309 | 0 |
| 05/12/2011 | 327 | 0 | 0 | 327 | 0 |
| 05/13/2011 | 336 | 0 | 0 | 336 | 0 |
| 05/14/2011 | 1,417 | 0 | 0 | 1,417 | (0) |
| 05/15/2011 | 0 | 0 | 0 | 0 | (0) |
| <u>Total</u> | 541,875 | 1,207,730 | 199,910 | 139,369 | (1,005,134) |
| | | | | | |
| 09/06/2011 | 7,235 | 43,990 | 0 | 0 | (36,755) |
| 09/07/2011 | 552 | 86,389 | 0 | 0 | (85,838) |
| 09/08/2011 | 5,421 | 87,635 | 0 | 0 | (82,214) |
| 09/09/2011 | 19,811 | 106,874 | 0 | 0 | (87,063) |
| 09/10/2011 | (938) | 90,245 | 0 | 0 | (91,184) |
| 09/11/2011 | (5,850) | 82,956 | 0 | 0 | (88,807) |
| 09/12/2011 | 10,203 | 102,825 | 0 | 0 | (92,621) |
| 09/13/2011 | 18,671 | 109,787 | 0 | 0 | (91,116) |
| 09/14/2011 | 32,827 | 125,001 | 0 | 0 | (92,174) |
| 09/15/2011 | 5,897 | 96,063 | 0 | 0 | (90,166) |
| 09/16/2011 | 2,500 | 92,952 | 0 | 0 | (90,452) |
| 09/17/2011 | 294 | 91,641 | 0 | 0 | (91,347) |
| 09/18/2011 | (10,977) | 80,449 | 0 | 0 | (91,426) |
| 09/19/2011 | (6,825) | 84,636 | 0 | 0 | (91,461) |
| 09/20/2011 | 5,307 | 97,271 | 0 | 0 | (91,965) |
| 09/21/2011 | 5,075 | 97,426 | 0 | 0 | (92,351) |
| 09/22/2011 | 9,711 | 101,838 | 0 | 0 | (92,127) |
| 09/23/2011 | 9,709 | 101,375 | 0 | 0 | (91,667) |
| 09/24/2011 | 16,498 | 108,604 | 0 | 0 | (92,106) |
| 09/25/2011 | 6,112 | 67,314 | 0 | 0 | (61,203) |
| <u>Total</u> | 131,232 | 1,855,272 | 0 | 0 | (1,724,040) |
| | | | | | |
| 10/31/2011 | 6,013 | 81,378 | 0 | 0 | (75,366) |
| 11/01/2011 | 7,474 | 58,280 | 0 | 3,804 | (54,611) |
| 11/02/2011 | 7,530 | 69,840 | 0 | 1,344 | (63,654) |
| 11/03/2011 | (927) | 87,143 | 0 | 0 | (88,070) |
| 11/04/2011 | 6,549 | 92,613 | 0 | 0 | (86,064) |
| 11/05/2011 | 4,417 | 93,775 | 0 | 0 | (89,358) |
| 11/06/2011 | 3,935 | 96,813 | 0 | 0 | (92,878) |
| 11/07/2011 | 9,761 | 79,199 | 20,006 | 0 | (89,444) |
| 11/08/2011 | 563 | 71,862 | 17,873 | 0 | (89,172) |
| 11/09/2011 | (170) | 81,596 | 7,592 | 0 | (89,358) |
| 11/10/2011 | 752 | 83,680 | 6,334 | 0 | (89,261) |
| 11/11/2011 | 1,525 | 87,907 | 2,867 | 0 | (89,249) |
| 11/12/2011 | (8,212) | 80,909 | 0 | 0 | (89,122) |
| 11/13/2011 | (11,403) | 47,865 | 0 | 0 | (59,268) |
| <u>Total</u> | 27,806 | 1,112,859 | 54,673 | 5,149 | (1,144,874) |

**Merrimack 2**

| Date | Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|---|
| 04/21/2011 | 47,046 | 125,061 | 169,193 | 0 | (247,208) |
| 04/22/2011 | 58,319 | 119,729 | 175,179 | 0 | (236,589) |
| 04/23/2011 | 52,074 | 167,449 | 127,522 | 0 | (242,896) |
| 04/24/2011 | 35,435 | 102,673 | 171,580 | 0 | (238,818) |
| 04/25/2011 | 69,247 | 165,391 | 131,880 | 0 | (228,024) |
| 04/26/2011 | 65,261 | 135,474 | 146,750 | 0 | (216,963) |
| 04/27/2011 | 77,861 | 75,720 | 183,191 | 0 | (181,051) |
| 04/28/2011 | 81,551 | 139,847 | 144,633 | 0 | (202,929) |
| 04/29/2011 | 1,472 | 7,302 | 0 | 0 | (5,831) |
| Total | 488,266 | 1,038,647 | 1,249,928 | 0 | (1,800,310) |
| | | | | | |
| 10/12/2011 | 22,924 | 8,223 | 0 | 21,768 | (7,067) |
| 10/13/2011 | 28,408 | 53,606 | 0 | 19,563 | (44,761) |
| 10/14/2011 | 37,209 | 62,591 | 0 | 19,648 | (45,030) |
| 10/15/2011 | 12,966 | 143,999 | 0 | 0 | (131,033) |
| 10/16/2011 | 4,579 | 135,498 | 0 | 0 | (130,919) |
| 10/17/2011 | 14,529 | 92,220 | 0 | 0 | (77,690) |
| 10/18/2011 | 21,657 | 70,299 | 0 | 14,964 | (63,607) |
| 10/19/2011 | 31,357 | 49,516 | 0 | 23,913 | (42,072) |
| 10/20/2011 | 7,678 | 47,600 | 0 | 9,449 | (49,372) |
| 10/21/2011 | 5,773 | 93,056 | 0 | 0 | (87,283) |
| 10/22/2011 | 9,336 | 212,000 | 0 | 0 | (202,664) |
| 10/23/2011 | 8,209 | 225,774 | 0 | 0 | (217,565) |
| 10/24/2011 | 7,938 | 93,745 | 0 | 1,572 | (87,379) |
| 10/25/2011 | 18,900 | 119,146 | 0 | 0 | (100,246) |
| 10/26/2011 | 6,732 | 137,123 | 0 | 0 | (130,392) |
| 10/27/2011 | 31,450 | 155,477 | 0 | 0 | (124,027) |
| 10/28/2011 | 28,336 | 189,992 | 0 | 0 | (161,656) |
| 10/29/2011 | 42,588 | 273,487 | 0 | 0 | (230,899) |
| 10/30/2011 | 5,991 | 69,394 | 0 | 0 | (63,403) |
| 10/31/2011 | (230) | 57,960 | 0 | 0 | (58,191) |
| 11/01/2011 | 7,804 | 51,991 | 0 | 7,229 | (51,416) |
| 11/02/2011 | 3,065 | 70,767 | 0 | 1,098 | (68,800) |
| 11/03/2011 | 2,510 | 88,994 | 0 | 0 | (86,484) |
| 11/04/2011 | 2,863 | 76,983 | 0 | 0 | (74,120) |
| 11/05/2011 | 18,564 | 253,475 | 0 | 0 | (234,911) |
| 11/06/2011 | 23,414 | 231,710 | 0 | 0 | (208,297) |
| 11/07/2011 | 46,288 | 62,878 | 151,713 | 0 | (168,304) |
| 11/08/2011 | 36,600 | 58,604 | 150,336 | 0 | (172,339) |
| 11/09/2011 | 25,961 | 67,594 | 161,352 | 0 | (202,985) |
| 11/10/2011 | 29,298 | 63,703 | 165,731 | 0 | (200,135) |
| 11/11/2011 | 27,993 | 92,212 | 157,425 | 0 | (221,644) |
| 11/12/2011 | (16,056) | 214,933 | 0 | 0 | (230,989) |
| 11/13/2011 | (24,601) | 198,405 | 0 | 0 | (223,006) |
| 11/14/2011 | 1,715 | 55,481 | 0 | 0 | (53,766) |
| Total | 531,748 | 3,878,438 | 786,556 | 119,204 | (4,252,450) |

**Schiller 4**

| Date | Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|---|
| 10/01/2011 | (14,509) | 53,873 | 0 | 0 | (68,382) |
| 10/02/2011 | (26,386) | 41,942 | 0 | 0 | (68,328) |
| 10/03/2011 | (23,181) | 45,460 | 0 | 0 | (68,641) |
| 10/04/2011 | (23,975) | 44,873 | 0 | 0 | (68,847) |
| 10/05/2011 | (26,502) | 42,269 | 0 | 0 | (68,772) |
| 10/06/2011 | (24,169) | 44,674 | 0 | 0 | (68,843) |
| 10/07/2011 | (25,270) | 19,739 | 0 | 0 | (45,009) |
| 10/08/2011 | (18,776) | 43,878 | 0 | 0 | (62,653) |
| 10/09/2011 | (19,991) | 32,171 | 0 | 922 | (53,084) |
| 10/10/2011 | (18,358) | 41,293 | 0 | 0 | (59,651) |
| 10/11/2011 | (15,495) | 50,580 | 0 | 0 | (66,076) |
| 10/12/2011 | (9,228) | 11,805 | 0 | 1,008 | (22,041) |
| 10/13/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/14/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/15/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/16/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/17/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/18/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/19/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/20/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/21/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/22/2011 | (4,995) | 5,746 | 0 | 0 | (10,741) |
| 10/23/2011 | (8,076) | 18,958 | 0 | 0 | (27,034) |
| 10/24/2011 | (13) | 27 | 0 | 0 | (40) |
| 10/25/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/26/2011 | (137) | 218 | 0 | 0 | (355) |
| 10/27/2011 | (159) | 357 | 0 | 0 | (516) |
| 10/28/2011 | (1,778) | 5,806 | 0 | 0 | (7,585) |
| 10/29/2011 | (2,167) | 9,248 | 0 | 0 | (11,415) |
| 10/30/2011 | 0 | 0 | 0 | 0 | 0 |
| 10/31/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/01/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/02/2011 | (534) | 1,080 | 0 | 0 | (1,615) |
| 11/03/2011 | (681) | 1,293 | 0 | 0 | (1,973) |
| 11/04/2011 | (213) | 411 | 0 | 0 | (624) |
| 11/05/2011 | (910) | 2,141 | 0 | 0 | (3,051) |
| 11/06/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/07/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/08/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/09/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/10/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/11/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/12/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/13/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/14/2011 | 0 | 0 | 0 | 0 | 0 |
| 11/15/2011 | 0 | 0 | 0 | 0 | 0 |
| Total | (265,504) | 517,842 | 0 | 1,929 | (785,276) |

**Schiller 5**

| Date | Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|---|
| 04/01/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/02/2011 | 12,801 | 24,224 | 0 | 4,358 | (15,782) |
| 04/03/2011 | 12,712 | 20,256 | 0 | 5,149 | (12,693) |
| 04/04/2011 | 13,050 | 8,688 | 0 | 9,186 | (4,825) |
| 04/05/2011 | 13,274 | 1,592 | 0 | 12,733 | (1,051) |
| 04/06/2011 | 11,868 | 0 | 0 | 11,868 | 0 |
| 04/07/2011 | 12,549 | 2,503 | 0 | 11,301 | (1,254) |
| 04/08/2011 | 10,439 | 1,704 | 0 | 9,995 | (1,260) |
| 04/09/2011 | 13,536 | 19,584 | 0 | 6,370 | (12,417) |
| 04/10/2011 | 13,993 | 16,094 | 0 | 6,319 | (8,420) |
| 04/11/2011 | 13,228 | 678 | 0 | 12,550 | 0 |
| 04/12/2011 | 10,032 | 1,554 | 0 | 8,478 | 0 |
| 04/13/2011 | 10,029 | 0 | 0 | 10,029 | 0 |
| 04/14/2011 | 10,697 | 255 | 0 | 10,442 | 0 |
| 04/15/2011 | 10,229 | 595 | 0 | 9,634 | 0 |
| 04/16/2011 | 10,307 | 25,046 | 0 | 3,114 | (17,853) |
| 04/17/2011 | 9,637 | 22,337 | 0 | 2,902 | (15,602) |
| 04/18/2011 | 12,540 | 9,777 | 0 | 8,247 | (5,484) |
| 04/19/2011 | 14,650 | 11,831 | 0 | 9,032 | (6,213) |
| 04/20/2011 | 15,190 | 12,343 | 0 | 9,427 | (6,579) |
| 04/21/2011 | 7,836 | 0 | 130 | 7,706 | 0 |
| 04/22/2011 | 5,862 | 0 | 0 | 5,862 | 0 |
| 04/23/2011 | 11,481 | 0 | 18,716 | 4,160 | (11,395) |
| 04/24/2011 | 8,430 | 0 | 1,902 | 6,980 | (452) |
| 04/25/2011 | 6,586 | 0 | 0 | 6,586 | 0 |
| 04/26/2011 | 5,558 | 0 | 0 | 5,558 | 0 |
| 04/27/2011 | 5,245 | 0 | 0 | 5,245 | 0 |
| 04/28/2011 | 5,157 | 0 | 0 | 5,157 | 0 |
| 04/29/2011 | 12,104 | 11,075 | 30,242 | 243 | (29,456) |
| 04/30/2011 | 11,069 | 39,808 | 0 | 620 | (29,359) |
| 05/01/2011 | 12,372 | 2,438 | 0 | 10,726 | (792) |
| 05/02/2011 | 14,756 | 5,333 | 0 | 11,980 | (2,557) |
| 05/03/2011 | 15,014 | 4,063 | 0 | 12,962 | (2,010) |
| 05/04/2011 | 19,711 | 7,175 | 0 | 15,169 | (2,633) |
| 05/05/2011 | 13,189 | 4,145 | 0 | 11,294 | (2,250) |
| 05/06/2011 | 11,438 | 2,359 | 0 | 10,335 | (1,256) |
| 05/07/2011 | 10,952 | 29,919 | 0 | 1,855 | (20,823) |
| 05/08/2011 | 9,949 | 26,291 | 0 | 2,615 | (18,958) |
| 05/09/2011 | 6,486 | 2,256 | 0 | 5,553 | (1,323) |
| 05/10/2011 | 7,036 | 0 | 0 | 7,036 | 0 |
| 05/11/2011 | 6,899 | 0 | 0 | 6,899 | 0 |
| 05/12/2011 | 6,677 | 0 | 0 | 6,677 | 0 |
| 05/13/2011 | 6,921 | 0 | 0 | 6,921 | 0 |
| 05/14/2011 | 6,305 | 0 | 0 | 6,305 | 0 |
| 05/15/2011 | 13,708 | 9,767 | 0 | 8,412 | (4,470) |
| 05/16/2011 | 19,653 | 47,357 | 0 | 257 | (27,961) |
| 05/17/2011 | 13,030 | 37,757 | 0 | 801 | (25,528) |
| 05/18/2011 | 15,463 | 16,309 | 0 | 4,359 | (5,205) |
| Total | 519,646 | 425,111 | 50,991 | 339,405 | (295,861) |

**Schiller 6**

| Date | Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|---|
| 03/04/2011 | (1,227) | 1,190 | 0 | 0 | (2,418) |
| 03/05/2011 | (16,481) | 33,985 | 0 | 0 | (50,466) |
| 03/06/2011 | (9,479) | 26,735 | 0 | 0 | (36,214) |
| 03/07/2011 | 2,342 | 14,180 | 0 | 0 | (11,838) |
| 03/08/2011 | (6,012) | 19,489 | 0 | 0 | (25,501) |
| 03/09/2011 | 405 | 4,136 | 0 | 1,211 | (4,942) |
| 03/10/2011 | (1,345) | 11,504 | 0 | 0 | (12,849) |
| 03/11/2011 | (1,177) | 1,635 | 0 | 0 | (2,811) |
| 03/12/2011 | (15,115) | 25,836 | 0 | 0 | (40,951) |
| 03/13/2011 | (15,240) | 23,861 | 0 | 0 | (39,101) |
| 03/14/2011 | (497) | 5,930 | 0 | 0 | (6,428) |
| 03/15/2011 | (1,411) | 3,749 | 0 | 0 | (5,160) |
| 03/16/2011 | (1,096) | 2,696 | 0 | 0 | (3,791) |
| 03/17/2011 | 0 | 0 | 0 | 0 | 0 |
| 03/18/2011 | 0 | 0 | 0 | 0 | 0 |
| 03/19/2011 | (10,129) | 24,718 | 0 | 0 | (34,847) |
| 03/20/2011 | (12,768) | 24,985 | 0 | 0 | (37,753) |
| 03/21/2011 | (2,939) | 8,969 | 0 | 0 | (11,908) |
| 03/22/2011 | (3,038) | 10,992 | 0 | 0 | (14,030) |
| 03/23/2011 | (3,871) | 12,992 | 0 | 0 | (16,863) |
| 03/24/2011 | (3,063) | 8,966 | 0 | 0 | (12,029) |
| 03/25/2011 | (564) | 2,254 | 0 | 0 | (2,818) |
| Total | (102,705) | 268,801 | 0 | 1,211 | (372,717) |

**Newington**

| Date | Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|---|
| 03/26/2011 | 0 | 0 | 0 | 0 | 0 |
| 03/27/2011 | 0 | 0 | 0 | 0 | 0 |
| 03/28/2011 | 0 | 0 | 0 | 0 | 0 |
| 03/29/2011 | 0 | 0 | 0 | 0 | 0 |
| 03/30/2011 | 0 | 0 | 0 | 0 | 0 |
| 03/31/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/01/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/02/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/03/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/04/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/05/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/06/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/07/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/08/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/09/2011 | 0 | 0 | 0 | 0 | 0 |
| 04/10/2011 | 0 | 0 | 0 | 0 | 0 |
| Total | 0 | 0 | 0 | 0 | 0 |

**Total All Units 2011**

| Total RPC ($) | Spot Purchases ($) | Bilateral Purchases ($) | PSNH Gen ($) | Avoided Fuel ($) |
|---|---|---|---|---|
| 1,872,364 | 10,304,700 | 2,342,057 | 606,268 | (11,380,662) |

**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Please reconcile the unit capacities listed in White testimony, FBW-1 (Bates 57) with the PSNH Capacity Resources listed in FBW-5 (Bates 61) by month.

**Response:**
See the attached table comparing resources used to meet customers' energy requirements in FBW-1 based on Seasonal Claimed Capabilities (SCC) as of December, 2011, to the monthly Forward Capacity Market capacity values included in the "PSNH Capacity Resources" column of FBW-5. There are differences between the sets of values principally because the values in FBW-5 are MW cleared in Forward Capacity Auctions (FCA) conducted in 2008 based on then FCA qualified MW (versus December, 2011 SCC ratings), and with ISO-NE in a surplus capacity position potentially only a percentage of resources' total capabilities (MW) are used to meet the ISO-NE Installed Capacity Requirement.

| | From FBW-1 | | FBW-5 - Forward Capacity Market | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Entitlement - MW (1) | | 2011 - MW | | | | | | | | | | | |
| Resource | Winter | Summer | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
| Amoskeag | 17.5 | 16.8 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 13.7 | 13.7 | 13.7 | 13.7 | 13.7 | 13.7 | 13.7 |
| Ayers Island | 9.1 | 8.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 |
| Canaan | 1.0 | 0.6 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.7 | 0.7 | 0.7 | 0.7 | 0.8 | 0.8 | 0.8 |
| Eastman Falls | 6.5 | 5.6 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 |
| Garvins/Hooksett | 14.0 | 12.5 | 11.0 | 11.0 | 11.0 | 11.0 | 11.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| Gorham | 2.1 | 2.0 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| Jackman | 3.6 | 3.6 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 |
| Smith | 15.2 | 11.7 | 9.8 | 9.8 | 9.8 | 9.8 | 9.8 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 |
| Merrimack 1 | 114.0 | 112.5 | 112.5 | 112.5 | 112.5 | 112.5 | 112.5 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 |
| Merrimack 2 | 343.0 | 338.4 | 326.5 | 326.5 | 326.5 | 326.5 | 326.5 | 301.8 | 301.8 | 301.8 | 301.8 | 301.8 | 301.8 | 301.8 |
| Schiller 4 | 48.0 | 47.5 | 47.5 | 47.5 | 47.5 | 47.5 | 47.5 | 44.4 | 44.4 | 44.4 | 44.4 | 44.4 | 44.4 | 44.4 |
| Schiller 5 | 42.6 | 43.1 | 45.6 | 45.6 | 45.6 | 45.6 | 45.6 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 |
| Schiller 6 | 48.6 | 47.9 | 47.9 | 47.9 | 47.9 | 47.9 | 47.9 | 44.7 | 44.7 | 44.7 | 44.7 | 44.7 | 44.7 | 44.7 |
| Newington | 400.2 | 400.2 | 400.2 | 400.2 | 400.2 | 400.2 | 400.2 | 373.4 | 373.4 | 373.4 | 373.4 | 373.4 | 373.4 | 373.4 |
| Lost Nation | 18.0 | 14.0 | 14.1 | 14.1 | 14.1 | 14.1 | 14.1 | 13.1 | 13.1 | 13.1 | 13.1 | 13.1 | 13.1 | 13.1 |
| Merrimack CT1 | 21.7 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 |
| Merrimack CT2 | 21.3 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 | 15.7 |
| Schiller CT 1 | 18.5 | 17.6 | 17.6 | 17.6 | 17.6 | 17.6 | 17.6 | 16.1 | 16.1 | 16.1 | 16.1 | 16.1 | 16.1 | 16.1 |
| White Lake Jet | 22.4 | 17.4 | 17.4 | 17.4 | 17.4 | 17.4 | 17.4 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 |
| Wyman 4 | 19.2 | 19.0 | 18.9 | 18.9 | 18.9 | 18.9 | 18.9 | 18.9 | 18.9 | 18.9 | 18.9 | 18.9 | 18.9 | 18.9 |
| VT Yankee | 20.9 | 20.1 | 20.9 | 20.9 | 20.9 | 20.9 | 20.9 | 20.1 | 20.1 | 20.1 | 20.1 | 20.9 | 19.7 | 20.9 |
| IPP Total (2) | 50.8 | 33.3 | 65.5 | 50.8 | 50.8 | 50.8 | 50.8 | 28.6 | 28.6 | 28.6 | 28.6 | 47.0 | 47.0 | 47.0 |
| Bio Energy buyout (3) | 10.0 | 10.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | 1,268.2 | 1,215.7 | 1,222.3 | 1,207.6 | 1,207.6 | 1,207.6 | 1,207.6 | 1,106.3 | 1,106.3 | 1,106.3 | 1,106.3 | 1,125.6 | 1,124.3 | 1,125.6 |
| HQ ICC | | | 0.0 | 0.0 | 150.3 | 150.3 | 150.3 | 97.8 | 97.8 | 97.8 | 97.8 | 97.8 | 97.8 | 97.8 |
| Lempster Wind | | | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 |
| "PSNH Capacity Resources" (from FBW-5) | | | 1,227 | 1,212 | 1,362 | 1,362 | 1,362 | 1,209 | 1,209 | 1,209 | 1,209 | 1,228 | 1,227 | 1,228 |

Notes:
1) FBW-1 figures are from the ISO-NE Seasonal Claimed Capability Report for December, 2011.
2) IPP Total does not include Lempster Wind PPA.
3) Bio Energy buyout contract is for energy only (no capacity).

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-003**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Please explain why Note 3 in White testimony, FBW-1 (Bates 57) states that Bio Energy is an energy only contract, yet the entitlement (capacity) is listed as 10.0 MW for both the summer and winter periods.

## Response:

Attachment FBW-1 supplements with backup detail FBW testimony on Bates page 51, lines 15-28, and identifies resources used to meet customers' energy requirements. Seasonal Claimed Capability ratings are used to convey the relative ratings of resources and use of the term Entitlement is intended to imply "rights to" energy, not capacity value. Regarding the Bio Energy buyout contract, energy deliveries are typically in 10 MWh/Hr quantities, as indicated.

Public Service Company of New Hampshire
Docket No. DE 12-116

Data Request STAFF-02
Dated: 07/31/2012
Q-STAFF-004
Page 1 of 2

**Witness:** Frederick White
**Request from:** New Hampshire Public Utilities Commission Staff

**Question:**
Reference White testimony, FBW-4 (Bates 60): Beginning in September 2010 through October 2012 and by month, please supply the forward looking Algonquin Gate $/MMBtu price for 2011 or remaining portion thereof by month.

**Response:**
Please see the attached table. As noted therein, PSNH does not have Algonquin data prior to October, 2011 so Transco Zone 6 data is included as a proxy.

$/MMBtu

| | | | Delivery Basis | | |
|---|---|---|---|---|---|
| Trade Date | Period Quoted | Henry Hub | Transco Zone 6 | Algonquin | NE Proxy Price |
| Sep-10 | Calendar Yr 2011 | 4.603 | 0.695 | | 5.297 |
| Oct-10 | Calendar Yr 2011 | 4.354 | 0.723 | | 5.077 |
| Nov-10 | Calendar Yr 2011 | 4.354 | 0.752 | | 5.107 |
| Dec-10 | Calendar Yr 2011 | 4.452 | 1.031 | | 5.483 |
| Jan-11 | Feb-Dec 2011 | 4.657 | 0.797 | | 5.454 |
| Feb-11 | Mar-Dec 2011 | 4.292 | 0.536 | | 4.827 |
| Mar-11 | Apr-Dec 2011 | 4.337 | 0.618 | | 4.955 |
| Apr-11 | May-Dec 2011 | 4.499 | 0.643 | | 5.142 |
| May-11 | Jun-Dec 2011 | 4.521 | 0.676 | | 5.198 |
| Jun-11 | Jul-Dec 2011 | 4.645 | 0.761 | | 5.405 |
| Jul-11 | Aug-Dec 2011 | 4.445 | 0.880 | | 5.325 |
| Aug-11 | Sep-Dec 2011 | 4.109 | 0.965 | | 5.074 |
| Sep-11 | Oct-Dec 2011 | 3.988 | 1.327 | | 5.314 |
| Oct-11 | Nov-Dec 2011 | 3.725 | | 1.579 | 5.304 |
| Nov-11 | Dec 2011 | 3.502 | | 3.120 | 6.622 |

Notes:
1) PSNH does not have Algonquin data prior to October, 2011 so Transco Zone 6 is included as a proxy.
2) $/MMBtu prices are averages over trading days in the month.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-005**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, page 6, (Bates 67): Please reconcile why outage OR-5 at Newington is considered a planned maintenance outage while reliability outages and other planned equipment replacement outages are not.

## Response:

Reliability outages and other planned equipment replacement outages are considered planned maintenance outages. There were no other reliability or planned equipment replacement outages in 2011.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-006**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, page 7 (Bates 68), lines 6-7 (plus following the description of each OR): Please describe the priority hierarchy in the outage backlog. In addition, please list the numbers of backlog jobs by unit and by priority as of December 1, 2011, July 1, 2011, and December 31, 2011. Further, for each priority one job listed, please provide the planned date of correction.

## Response:

NGS Plant Manager is the work management system used by the facilities to track work requests or job orders. Each job order is categorized as to whether it requires a unit outage in order for the work to be performed. Job orders are also able to be prioritized with a range of '1' to '5' with '1' being the highest priority and '5' being the lowest priority. An outage backlog is maintained for each unit to be reviewed each day to manage maintenance work; and in particular the backlog is to be reviewed prior to a unit outage. During an outage backlog review, a discussion is held with a multi-disciplined management team of supervisors, foreman and managers to determine a work plan.

The highest priority jobs are jobs that are likely to take the unit off in the immediate future or require equipment to be out of service for the work to be performed. These are jobs that will be completed during the next outage. Other work including medium and lower priority jobs will be discussed among the management team. Based on the planned outage duration considering critical path items and market prices, availability of resources, status of the unit, upcoming scheduled outage timing, upcoming expected energy demands, etc., job orders will be assigned for completion during the outage.

The NGS Plant Manager system is continually updated as new work requests are identified and work completed. PSNH is investigating the opportunity to generate a report as requested. However, as a tracking and planning tool, this request does not have a historical report generator to specifically respond to this question.

Public Service Company of New Hampshire
Docket No. DE 12-116

Data Request STAFF-02
Dated: 07/31/2012
Q-STAFF-007
Page 1 of 1

**Witness:** William H. Smagula
**Request from:** New Hampshire Public Utilities Commission Staff

## Question:

Reference Smagula testimony, page 8, lines 15 – 19, (Bates 69): Assume that the inspection results described were such that the pump could not be continued to operate. What would the duration of time be that the unit would not be available for service? Also, please explain what actions PSNH is taking regarding equipment replacement and procurement of spare parts for outdated equipment at its three main generating stations.

## Response:

The availability of Newington would not be impacted should one of the two a-c lube oil pumps be unable to operate. One pump provides back-up for the other in case one fails. However, there is also a d-c emergency back-up pump (a third pump) that is part of this important lube oil system, so if an a-c pump is not available for a short period of time, there is still a back up in service. In fact, this scheme was utilized while a replacement pump was made by the PSNH Generation Maintenance machine shop. An extra spare was made and is also in stock.

Regarding the broader issue of parts no longer supported by the original equipment manufacturer, we often deal with this issue at our fossil fuel and hydro facilities. This is a very common issue throughout the power, paper and other industries where equipment has been in service for many years. This does not imply the equipment is outdated; rather it is more of a business reality. Some companies do go out of business or in other ways do not support maintenance of a former product lines. In many cases, other companies step up to fill these gaps in the industry. Otherwise PSNH will make a replacement part as was done in this case, or we will substitute a replacement from a current supplier of similar equipment.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-008**


**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Smagula testimony, page 9, lines 2 – 3 (Bates 70): Please explain what led to the pluggage.

**Response:**
The Schiller 5 circulating fluidized bed (CFB) boiler is designed to return the larger particles in the outlet flue gas stream to the lower furnace combustion area through six cyclone and dip leg return sections. This area is naturally prone to pluggage over time. The rate of pluggage can vary based on fuel qualities, the operation of the boiler, etc. It is routine to inspect and clean as necessary both the cyclones and dip legs during maintenance outages. As of this November 12 outage, Schiller 5 had not had a long maintenance outage since it returned to service in May from the spring scheduled maintenance overhaul. This long run is a result of maintenance efforts the station has implemented to reduce pluggage build-up. The station has also identified ways to operate the unit and manage cyclone pluggage to accommodate a planned maintenance outage during lower market periods.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-009**


**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, page 9, lines 13 - 14 (Bates 70): Was the cause for the vibration and elevated temperatures determined? If so, please explain.

**Response:**
Specific to the Merrimack Unit 2 outage beginning December 7, the 2A gas recirculation fan experienced high vibration and the 2B fan outboard fan bearing experienced high temperature. The high temperature in the 2B outboard bearing was believed to be caused by shallow grooves worn in the shaft journal by the bearing oil slinger rings. These grooves allowed lube oil to escape from the area between the lower surface of the journal and the bearing, reducing the development of the "oil wedge" that acts to support the weight of the spinning shaft. The journal was also noted to be very slightly out of round. The repair was to hone the journals true, both inboard and outboard ends, which resolved both the groove and the slight out of round wear issues; and left both ends the same size to use identical sized bearings. The bearings were rebabbited to an elliptical configuration using the new journal size and using an improved babbit compound as well. These activities reduced to the temperature to an acceptable level.

The obvious cause of the vibration in the 2A fan was less conclusive. An issue with the coupling was noted as the most likely cause. Some wear noted on the coupling teeth is thought to have allowed movement between the coupled shafts. It was decided to complete a thorough tune-up on this fan including pressure washing the fan to remove ash buildup, checking and adjusting alignment and repairing the grout on the bearing pedestals. These actions reduced the vibration of the 2A fan to an acceptable level.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-010**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, page 10, line 3 (Bates 71): Please explain why the Merrimack Unit #1 April outage could not have been put off until the October tie-in outage.

**Response:**
The outage for Unit 1 in 2011 originally was scheduled from early September to mid-October. This outage was longer than typical because no annual outage occurred in 2010 and it was the first of two critical tie-in outages with the Scrubber. As the scope of this outage became more defined in late 2010 and early 2011, it became evident that accomplishing all the unit's routine maintenance work and all the tie-in work created sufficient risk of full success to achieve all objectives (schedule, start-up, cost, reliability upon coming on line, etc.). An example of new information, a two unit outage was needed in order to do 115 kV hi-yard transmission work. This work was related to the scrubber and other station needs. As a result, a decision was made to split the outage work into two separated groupings and do the work in two separate outages. Emphasis was placed on managing to the same budget values. The modified outage plan was for an outage in April/May and a shorter outage in September.

The reason for this outage plan changed was fivefold. First, as the scope was broken down and analyzed the numerous station based tasks, combined with the scrubber tie-in work, would have caused a very large challenge to both management and the physical workforce to complete all work with quality and timeliness. This introduced an incremental amount of risk that could be avoided if the work was divided into two pieces. The first start-up of the scrubber with an operating unit was the priority event that should have the attention of all with minimal distraction. Second, conducting a large number of activities in the spring would enhance the unit's reliability for the summer's heavier load period and as such provide more customer value. Third, replacement power cost was low during the spring outage window. Fourth, a two unit outage was needed by PSNH Transmission in the spring so an extra outage could be avoided on Unit 1. (Please also see Staff-02 Q-Staff-011.) Finally, the new outage schedule would allow for more time between the end of the Unit 1 fall tie-in outage and the Unit 2 tie-in outage which would accommodate tuning and troubleshooting of the scrubber as needed. Note: As has been stated in various Clean Air Project updates, the Unit 1 outage in the fall was concluded with an excellent and trouble free start-up and no scrubber tie-in or startup problems either. This is one demonstration of the success of these two efforts; managing the Unit 1 2011 outage scope in two work periods as done was a very positive contributor to this success.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-011**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, page 10, lines 13 - 15 (Bates 71): Please describe in detail the transmission work involved. As part of your response, include any efforts made by either PSNH or NU and in conjunction with the ISO-NE to perform the required transmission work in October or in conjunction with unit annual maintenance outages.

## Response:

The transmission work occurring in the Merrimack Station hi-yard during the spring Unit 1 routine maintenance outage involved the addition of equipment, reconfiguration of equipment, and numerous inspections and testing activities. A new breaker (V159) was added to the No. 1 buss which was to be used to connect to the new scrubber electrical substation used to power the Clean Air Project. As part of this work and to improve the electrical scheme of the hi-yard, the starting transformer for Unit 1 (CMT 7) was changed from the No. 2 buss to the No 1 buss and now would also serve the new V159 breaker. This work required both a Unit 1 outage as well as a concurrent outage with Unit 2 for a portion of the work. Completing this work, concurrent with the originally scheduled, much larger Unit 1 outage and complex scrubber tie-in work (mechanical, electrical, control system, etc.) would have created incremental risk of success. Please also see response to Staff-02 Q-Staff-010.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-012**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, page 10, line 3 (Bates 71) and page 11,lines 1 – 2 (Bates 72): Please reconcile the differences in the Merrimack #1 outage dates.

**Response:**
In Smagula testimony, page 11 (Bates 72), line 1 the date should read "September 25" which agrees with the date on page 10 (Bates 71).

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-013**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, page 10, line 3 (Bates 71): Please have available for review the annual outage reports for the outages listed at PSNH offices in Manchester, NH or at the respective plant offices.

**Response:**
The 2011 scheduled maintenance outage summaries for Merrimack, Schiller and Newington stations will be available for review by the Staff consultant.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-014**


**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:
Reference Smagula testimony, Attachment A, page 4 (Bates 76): The last paragraph portrays management efforts as a top-down approach. The intent of the recommendation was that an atmosphere would create a bottoms-up approach such that a mechanic would feel comfortable to bring questionable workmanship to the attention of management early in the outage. Please reconcile how PSNH's approach as described does that.

## Response:
PSNH believes the efforts taken are consistent with a bottom-up approach and create an atmosphere where employees and contractors are comfortable bringing potential workmanship issues to the attention of PSNH Management. Part of the bottom-up approach is assigning PSNH liaisons early on in the pre-outage planning process; this among other things allows the PSNH liaison, contractor team leaders and supervisors to develop a good working relationship. Once the outage starts the PSNH liaisons monitor work progress and interact with contractor team leaders and workers on a regular basis (several times a day). Any issues that are identified by contractors in the field are discussed directly with the PSNH liaison. These issues could be related to scheduling, workmanship, safety etc. PSNH liaisons are the direct communication path to PSNH management and provide a minimum of one project update a day during the outage, if workmanship issues are identified they are discussed and the appropriate action is taken.

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**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-015**


**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, Attachment A, pages 5 -7 (Bates 77-79): Please supply organizational charts for NU vegetation management showing reporting paths, individuals by name, and the organizations by which they are employed. Please distinguish between transmission and distribution personnel and organizations with separate charts and include other operating companies. As part of your response, please identify the decision makers for VM policy.

## Response:

Refer to attachment.

**Northeast Utilities Vegetation Management Organization Chart**

**August 9, 2012**

Manager – Northeast Utilities Vegetation Management[i]

| PSNH | CL&P | WMECO |
|---|---|---|
| Supervisor | Supervisor | Senior Program Coordinator |
| Arborist | Senior Program Coordinator | Billing Clerk |
| Arborist | Senior Program Coordinator | |
| Arborist | Arborist | |
| Arborist | Arborist | |
| Arborist | Arborist | |
| Billing Clerk | Arborist | |
| Billing Clerk | Arborist | |
| | Arborist | |
| | Billing Clerk | |

The Vegetation Management (VM) organization chart provided above is for the 3 Northeast Utilities distribution operating companies prior to the merger with NStar. A new Vegetation Management organization, including NStar and Transmission, will be developed before the end of 2012.

The decision makers for Vegetation Management policy include the VM Supervisors at PSNH and CL&P, the Sr. Program Coordinator at WMECO, the VM Manager, the Director of Distribution Engineering, the Vice President of Operations Services, the operating company Presidents and the operating company Vice Presidents of Operations.

[i] Reports to NUSCO Director – Distribution Engineering

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**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-016**


**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, Attachment A, pages 5 -7 (Bates 77-79): Please explain what "reclaiming the full width of the right-of-way" means as it is used throughout this reference.

**Response:**
The attachment explains full width clearing .

The FERC has recommended that "to the extent a utility manages vegetation only on maintained rights-of-way rather than full rights-of-way, it should work toward reclaiming the full right-of-way width where feasible." See page 47, "Report on Transmission Facility Outages during the Northeast Snowstorm of October 29–30, 2011, Causes and Recommendations," Prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, available from the FERC website at: http://www.ferc.gov/legal/staff-reports/05-31-2012-ne-outage-report.pdf

Full Width Clearing refers to the horizontal measurement of the area where trees and brush are removed under and along off-road distribution rights-of-way where the right-of-way has not been cleared to the full width allowed by the easement. When easements are obtained, the contract specifies the area encompassed by the easement and the grantees right to construct poles and wires, cut and clear trees, and access the right-of-way. The area that can be cleared is specified in surveying terms and can be easily measured in the field. The right-of-way may or may not have been cleared to the full width at the time of construction or trees may have encroached on the right-of-way over time. In either case, the current width is not the full width. To improve reliability performance and visual and physical access to the lines, rights-of-way will be cleared to the width allowed by the easement contract.

Figure 1 illustrates a right-of-way where trees are growing within the bounds (orange) of the full width of the easement prior to Full Width Clearing.

Figure 1.

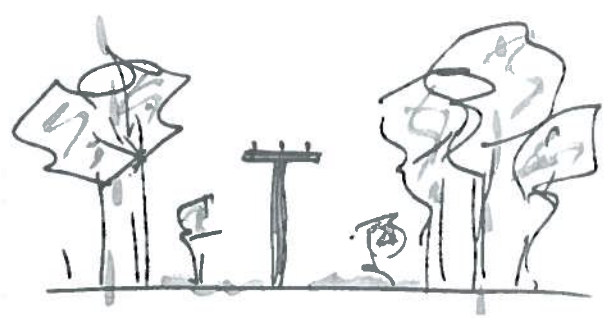

Figure 2 illustrates a right-of-way where trees have been cleared following Full Width Clearing to the bounds (orange) of the right-of-way.

Figure 2.

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**Dated: 07/31/2012**
**Q-STAFF-017**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, Attachment A, page 7 (Bates 79): Please explain how a tree leaning away from the power line could fail and cause an outage.

## Response:

A tree leaning away from the power lines could cause an outage during strong winds by being blown toward and onto the line.

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Docket No. DE 12-116

Data Request STAFF-02
Dated: 07/31/2012
Q-STAFF-018


Witness: William H. Smagula, Robert D. Allen
Request from: New Hampshire Public Utilities Commission Staff

**Question:**
Reference Smagula testimony, Attachment A, page 7 (Bates 79): Please supply the detailed results of the November 28, 2011 through December 30, 2011 circuit patrol. As part of your response, please indicate whether patrols such as this have been conducted on all lines located in rights-of-way and serving generating plants from 2007 through 2011 inclusive. If not, please provide the details as to which lines were patrolled in this fashion and which were not by year.

**Response:**
Detailed results of November 28, 2011, through December 30, 2011 circuit patrol are as follows:

This was a patrol of lines 332, 334, and 335 (Garvins Falls-Hooksett Hydro-Rimmon) and it addressed 189 poles. PSNH identified 22 hazard trees.

- Between poles 183 and 184, dying white pine.
- Between poles 175 and 176, rotted red maple.
- Between poles 169 and 168, large leaning rotted dead white pine.
- At pole 162, small dead white pine and rotted red maple.
- Between poles 151 and 152, large white pine and a rotted red maple.
- Between poles 108 and 109, large dying leaning red oak.
- Between poles 107 and 108, red oak with rot and fungus.
- Between poles 132 and 133, white pine leaning toward lines.
- Between poles 102 and 103, white oak with ice storm damage leaning towards lines.
- At pole 84, several dead pines.
- Between poles 91 and 92, several rotten pines leaning towards lines.
- Between poles 75 and 79, several dead and dying oaks.
- Between poles 61 and 62, large rotten white pine.
- At pole 31, red maple leaning towards line with large cavity.

The "patrols" are done while we are mowing the floor of the ROW. Hazard trees are identified by the contractors and removed when the vegetation maintenance of the line is completed (generally during, or the year after, mowing).

| NAME | CIRCUIT | YEAR |
|---|---|---|
| Amoskeag | 355,354 | 2011 |
| Ayers | 3149 | 2011 |
| Canaan | 355X | 2011 |
| Eastman Falls | 337,398 | 2011 |
| Garvins Falls | TB36 | 2010 |
| Gorham | 351,352 | 2008 |
| Hooksett Hydro | 332,335 | 2010 |
| Jackman | n/a | n/a |
| Lost Nation | TB1G | 2010 |
| Smith Hydro | Z177 | 2011 |
| White Lake | n/a | n/a |

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**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-019**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:
Reference Smagula testimony, Attachment A, page 8 (Bates 80): Please supply the PSNH organization/department that will be performing these analyses and the individual(s) responsible to do so. As part of your response, please indicate what PSNH's backup capability is in case the individual trained in this subject matter terminates employment with PSNH.

## Response:
System Planning & Strategy is the department which is developing the in-house capability to perform the transient stability analysis or determine whether a particular analysis should be conducted using outside resources. A Senior Engineer is the individual responsible. As he develops expertise in this area, we expect to use this expertise to develop others within the group. If others have not been adequately trained or gained an appropriate level of experience, and he is no longer an available resource, PSNH has the capability to contract with an outside resource.

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, Attachment A, page 8 (Bates 80): The bottom paragraph discusses a specific incident where the transmission and distribution groups collaborated on a transient stability study. Please supply the internal PSNH procedures that require such collaboration to take place when either transmission or distribution system changes are planned.

## Response:

The study referenced in the testimony was a "Transient Analysis" specifically looking at the effect of capacitor bank additions to the transmission and distribution systems along with any effect on local generation.

The NH distribution and transmission groups have a history of collaboration. The collaboration is not required by single procedure but falls under the direction of "good utility practice." The addition of transmission level capacitors will have an effect on the distribution system along with local generation. The required studies for installation of capacitors must include the interaction of the new facilities with existing distribution and generation facilities. Collaboration of the groups is required to insure the study is accurate and complete.

There are several documents which point to the need for collaboration.

The capacitor bank additions described in the Smagula testimony, Attachment A, page 8 (Bates 80), are for an ISO-NE approved project. As such, the project requires an ISO Proposed Plant Application (PPA). To obtain the PPA, sufficient studies must be performed to insure no adverse affect on "Market Participants," including the PSNH distribution system. See attached ISO Planning Procedure PP5-3. The studies include the review and feedback of ISO Market Participants.

The transmission standard for 115 kV capacitor banks specifies the type of studies required. The standard requires the effect of each bank on the "system" to be studied. The term "system" covers the transmission and distribution systems. Distribution input to the study is required to fully evaluate the effect on the "system."

# ISO NEW ENGLAND PLANNING PROCEDURE 5-3

## GUIDELINES FOR CONDUCTING AND EVALUATING PROPOSED PLAN APPLICATION ANALYSES

EFFECTIVE DATE: March 5, 2010

# GUIDELINES FOR CONDUCTING AND EVALUATING PROPOSED PLAN APPLICATION ANALYSES

## TABLE OF CONTENTS

# GUIDELINES FOR CONDUCTING AND EVALUATING PROPOSED PLAN APPLICATION ANALYSES

## 1. Introduction

### 1.1 Section I.3.9 Requirement

Under Section I.3.9 of the Tariff, each Governance Participant must submit plans for additions to or changes in facilities that might "have a significant effect on the stability, reliability or operating characteristics of the Transmission Owner's transmission system, the transmission facilities of another Transmission Owner or the system of a Market Participant". Section 1 of ISO New England Planning Procedure PP5-1, "Procedure for Review of Governance Participant's Proposed Plans", describes the process and contains the procedures to be followed in complying with the stated requirement. Section 1 also summarizes the information recommended or required for a formal submittal of a Proposed Plan Application. PP5-1 also contains the Proposed Plan Application forms and description of the information required.

This PP5-3 guideline is intended to be an aid to both the Governance Participant filing a Proposed Plan Application and the committees who evaluate the effects of proposed additions or changes. To allow opportunity for an orderly and timely review, applicants are strongly recommended to supply supporting information in accordance with these guidelines with lead times appropriate for anticipated "Level of Analysis Required" (see PP5-3, Section 3.1.2). It is further recommended that the Governance Participant confirm with the ISO and, if applicable, the Task Forces that information is complete prior to formal submittal of its Proposed Plan Application.

### 1.2 Using the Guidelines

These guidelines are structured according to the facility for which an application is required and by concerns specific to that type of facility. Each section outlines the information to be provided and the measures used to evaluate the information in determining if the proposed facilities will or will not have a "significant adverse effect" on the stability, reliability or operating characteristics of the electric power system.

Generating unit operating characteristics and other power supply related concerns are addressed in **Section 2.0 Generating Units – Power Supply Concerns**. Since a generating unit can affect the performance of the integrated generation/transmission bulk power system, the guidelines of Section 3.0 also apply for generation Proposed Plan Applications.

Transmission facility additions and changes refer to transmission lines and substation equipment for which Proposed Plan Applications are required, including HVDC terminals and static VAR compensators and are addressed in **Section 3.0 Generating Units and Transmission Facilities – Bulk Power System Performance.**

Guidelines for protection and control system changes requiring approval of Proposed Plan Applications, including Special Protection Systems (SPSs) and Dynamic Control Systems, are discussed in **Section 4.0 Protection Systems and Dynamic Control Systems**. A list of defined terms utilized in this guide is included in **Section 5.0 Definitions**.

## 2.0 Generating Units - Power Supply Concerns

Governance Participants filing a Proposed Plan Application shall provide all information requested on the generation Proposed Plan Application, which is Attachment 1 to PP5-1. Only complete applications will be accepted for review. New units are required to meet specific criteria, listed below. Non-compliance with the criteria below will be grounds for rejecting the Proposed Plan Application. A Proposed Plan Application should be rejected if a significant adverse impact on the existing electric system is identified. The Proposed Plan Application will not be accepted until it is modified to eliminate the identified negative impact.

a. Both physical and contractual operating characteristics of all units must be reported. During emergency conditions, including the entire spectrum of load levels from peak to light load, the most restrictive operating limitations, either physical or contractual will be used to determine the unit's operation. Identify the normal and emergency operating characteristics of the unit from a physical unit characteristic perspective. Also, identify the contractual operating characteristics, if different. Particular attention should be given to operating limits (high and low), minimum shut down times, minimum run times, and start up times.

   If unable to complete the NX-12 form, provide a detailed description of the amount of dispatch control the ISO will have in determining the operation and/or output of the unit. Indicate when, and how frequently the unit can be reduced to its low limit and/or shut down during emergency conditions.

   Provide information on any constraints due to waste to energy conversion, primary/secondary steam requirements, or any other physical constraints that determine operating flexibility.

b. If a new unit is 10 MW or larger, it must be equipped with a functioning turbine governor.

c. The settings for underfrequency relays must comply with NPCC guidelines and be approved by the host utility.

## 3.0 Generating Units and Transmission Facilities - Bulk Power System Performance

### 3.1 Classification and Reporting of Analyses

This section provides guidance on the bulk power system performance analyses required to support a generation or transmission Proposed Plan Application. The type of change/addition and its potential effects on the interconnected system determines the depth of analysis expected in support of a particular Proposed Plan Application. It defines the levels of analysis expected over the range of Proposed Plan Applications and guides the applicant to that level best suited to the particular application at hand. General guidance on performance measures and expectations is provided in Subsection 2.0. Subsections 3.0, 4.0, and 5.0 provide specific details on expected studies.

### 3.1.1 Areas of investigation

A Proposed Plan Application analysis is expected to demonstrate the impact of the change/addition on system performance in two transmission-related areas: area transmission requirements and transmission transfer capabilities. As applicable, the analysis should demonstrate the impact on the power supply concerns detailed in Section 2.0 above.

Impact on area transmission requirements is investigated by showing that the resultant system (after the change/addition) has sufficient transmission capacity to serve the area loads under the conditions noted below and in Planning Procedure 3 "Reliability Standards for the New England Area Bulk Power System" (the "Reliability Standards")(Section 3). Impact on inter-Area and intra-Area transmission transfer capability should be demonstrated for the conditions noted below and in the Reliability Standards (Section 4).

### 3.1.2 Level of analysis required

Based on factors such as the size of a generator and/or operating voltage level and connection of a transmission line (radial or networked), four levels of analysis are identified for supporting a particular Proposed Plan Application. Additional analyses may be requested by the Principal Committees, Task Forces, or individual Governance Participants. The levels are defined as follows:

Level 0: A Proposed Plan Application is not required

Level I: A Proposed Plan Application is required for information only; reporting of study results or analysis is not required

Level II: As appropriate, analyses based on testing such as load flow, short circuit, transient network analysis (TNA), etc. should address one or both of the following:

- Area Transmission Steady State Assessment (Reference: Reliability Standards, Sections 3.0 and 3.2)
- Transfer Capability Assessment (Reference: Reliability Standards, Sections 4.0, 4.1 and 4.2)

Detailed descriptions will be found in Section 3.3 Steady State Analysis and Section 3.4 Other Testing.

Level III: As appropriate, the analyses should include Level II testing and should address one or more of the following:

- Area Transmission Stability Assessment (Reference: Reliability Standards, Sections 3.0 and 3.1)
- Dynamic Transfer Capability Assessment (Reference: Reliability Standards, Sections 4.0, 4.1 and 4.2)

Detailed descriptions will be found in Section 3.3 Steady State Analysis Section 3.4 Other Testing, and Section 3.5 Stability Analysis.

PP5-1 defines items that may require Proposed Plan Applications. This list has been expanded and augmented with a flow chart to guide the Proposed Plan applicant to the appropriate minimum level of analysis consistent with the proposed addition or change. The expanded list of items, Table 1, and the Level of Analysis Flow Chart, Figure 1 are in Attachment 1 of this guideline.

The following steps will help guide the Proposed Plan applicant in determining the appropriate minimum level of analysis:

a. From Table 1, identify each proposed item that is to be added or changed. After the item is identified, and if appropriate, choose the class of voltage.

b. From column 3 of Table 1, read the appropriate minimum level of analysis or "See Figure 1"; i.e. Level of Analysis Flow Chart.

c. Follow the steps in the Level of Analysis Flow Chart to identify the appropriate minimum level of analysis.

If the proposed addition or change involves more than one pass through the list of items or flow chart, then the appropriate minimum level of analysis is the highest level identified.

In general, if the proposed addition or modification is not listed in Table 1, then no Proposed Plan Application is required; i.e. Level 0. If the proposed addition or modification is listed in Table 1 as requiring a Proposed Plan Application, but it does not affect other Governance Participants or neighboring Control Areas, then the application is required for information only; i.e. Level I.

For the more complex Level II analyses and those of Level III, the applicant is strongly urged to submit a single scope of work for review by both the Transmission and Stability Task Forces. This scope should include the items listed in Sections 3.1.3.1 and 3.1.3.2 below: a brief description of the facility changes and a description of the system representation to be used in the study, including all major assumptions regarding test conditions for load flow, dynamics and/or other studies. Periodic status reports to the respective Task Forces, summarizing testing and results to date, will assist in completing these complex analyses in a timely manner.

Based on past analyses, the expected amount of time generally needed from initial submission of study work to completion of review (and formal submittal of application) is as follows:

Level I: No study work submitted
Level II: 1 to 4 months, depending on complexity
Level III: 3 to 12 months, depending on complexity

3.1.3 Reporting

This section contains guidelines for the content of reports submitted in support of Proposed Plan Applications. Materials submitted with a Proposed Plan Application must be adequate to support the proposal. It is recognized that it may be necessary to conduct a Proposed Plan study using preliminary data describing transmission line and machine parameters. Using such data implies an obligation to provide more specific information at a later time.

3.1.3.1 Description of Proposed Facility(ies)
Describe the proposed facilities including how the modified system will be operated and a brief reason for the proposal.

Provide a map showing geographical location, a one-line diagram of the affected portion of the power system, and a switching diagram including the proposed facility and nearby facilities.

3.1.3.2 Description of System Representation Used in Studies
For Level II and III analyses, as appropriate, provide:

3.1.3.2.1 Load flow Studies - Year, season, load level, base interchanges, list of future facilities represented, source of representation and pertinent test assumptions as described in Section 3.1.1, Conditions to be Tested (below).

3.1.3.2.2 Dynamics Studies - Source of machine data and other dynamics modeling and data, load model, special protection systems and other pertinent assumptions as described in Section 3.5.1, Conditions to be Tested (below).

3.1.3.2.3 Other Testing (transient network analysis, short circuit analysis, etc.) - Source of representation, including machine data and network equivalents. Other pertinent test assumptions should be noted where they differ from those described above for load flow studies.

3.1.3.2.4 Analysis and Reporting of Results
For Level II and III analyses, as appropriate, provide a description of the baseline performance without the modification, a summary of the tests conducted with the modification and the resulting system performance in terms of its conformance to the Reliability Standards. Information of interest is discussed below in Section 3.3.1.2, 3.3.1.3 and 3.3.1.4 and Section 3.3.2 for Steady State Analyses, Section 3.5.1.2, 3.5.1.3 and 3.5.1.4 and Section 3.5.2 for Stability Analyses and Section 3.4.0 for Other Testing. This information should be sufficient to clearly demonstrate system performance without including exhaustive details of all results.

3.1.3.2.5 Conclusions

Present arguments for approval of application consistent with Section 3.3.3 for steady state analyses, Section 3.5.3 for stability analyses and Section 3.4 for other testing.

## 3.2 Evaluation

The Reliability Committee and its Task Forces will evaluate a number of aspects of the studies submitted in support of a Proposed Plan Application. The evaluation of the acceptability of the proposed changes or additions begins with review of the adequacy and acceptability of testing and test results. The results of tests performed and submitted in support of proposed additions or changes in facilities should clearly demonstrate compliance with the desired level of reliability as outlined in the Reliability Standards. The level of performance expected is intended to: 1) assure the reliability of the overall interconnected system and minimize the risk of widespread cascading outages due to overloads, instability or voltage collapse; and 2) demonstrate that the Nuclear Plant Interface Requirements (NPIRs) as documented in ISO Form NX-12 are met. Sections 3, 4 and 5 of the Reliability Standards establish a minimum design criteria by outlining representative contingency tests and assessment.

Demonstration of acceptable system performance under the enumerated conditions and assumptions should be considered the minimum level of compliance. Additional testing, evaluations or adjustments to assumptions may be deemed necessary to either assure the adequacy of system performance or to distinguish a sensitivity to one particular condition from a more general system weakness. The final conclusions and recommendations should be based on the informed engineering judgment of the Reliability Committee and its Task Forces with the objective of assuring that proposed changes or additions in facilities will not have a significant adverse impact on the stability, reliability or operating characteristics of the interconnected bulk power system.

Generally, if results of testing indicate that the system is not sufficient to accommodate the proposed changes or additions in facilities, system reinforcements or other mitigating measures will be required. These reinforcements or mitigating measures should fully alleviate all adverse impacts which were introduced by the proposed change or addition.

Occasionally, testing may identify weaknesses in the system prior to introduction of the proposed change or addition in facilities. The degree to which the proposed change or addition further degrades the stability, reliability or operating characteristics of the system will be of primary concern. Where no significant impact is identified, it may be possible to conclude that the proposed change or addition does not degrade system reliability. This judgment should take into account the frequency, duration, magnitude and consequences of any conditions where reliability violations occur both prior to and subsequent to the proposed changes or additions.

## 3.3 Steady State Analysis

It is the responsibility of the Governance Participant submitting the Proposed Plan Application to identify the most severe conditions that can reasonably be expected to exist. It must be demonstrated that under such conditions, the proposed additions or changes will not have any significant adverse impact upon the reliability or operating characteristics of the bulk power system; otherwise, the Governance Participant must propose system modifications, protection systems and/or operating restrictions on the proposed addition which will eliminate such adverse impact. Studies demonstrating steady state performance must then simulate normal conditions as well as conditions that stress the system beyond "typical" combinations of load level, generation dispatch and power transfers. Since it is necessary for supporting studies to reflect conditions expected to exist at the time of a future system modification, such conditions might include other future facilities with or without Proposed Plan approval that may be installed by about the same point in the future. Upon request, the Transmission Task Force will assist the Governance Participant in identifying reasonably stressed conditions for testing.

### 3.3.1 Conditions to be Tested

#### 3.3.1.1 Assumptions

a. Selection of Year or Year(s) to Model - The initial year chosen for study is normally that of the anticipated system modification. However, the following matters may need to be considered:
   - other facilities coming on-line in the same time period; and
   - other influences in the area, such as changes in contracts.

The Reliability Committee and its Task Forces will provide guidance in selecting the year(s) and related conditions to be studied.

b. Source of Base Case - The base case should have its origin from the ISO's library of cases, with changes or modifications as provided by the Stability and/or Transmission Task Forces.

c. Other Proposed Facilities - Inclusion of planned or proposed facilities in a study is subject to the status of other Proposed Plan Applications, the System Impact Study queue, and the Subordinate Proposed Plan Application Policy. Consequently each proposed or planned facility must be individually identified in the scope of the study with the aid of the Task Forces and the ISO prior to the start of the study. Having identified the planned or proposed facilities to include in the study, the study can be done with either or both of the following approaches: 1) the facility assumed installed in the base condition with tests determining the sensitivity of system response without the facility, or 2) as not installed in the base condition, but with sensitivity tests conducted with the facility included. The Governance Participant conducting the analysis should judge which approach is appropriate for the evaluation.

d. Modeling Devices - Models for devices of particular concern, such as HVdc terminals, are available from the ISO. It is the responsibility of the Proposed Plan applicant to properly represent these devices where appropriate.

e. Load Level - Disturbances should be studied at peak load levels since they usually promote more pronounced thermal and voltage response within the New England Control Area than at other load levels. However, other load levels may be of interest in a particular analysis. This should be determined and, as appropriate, additional studies should be conducted.

f. Generation Dispatch - Testing should not be restricted to only typical dispatch; rather the dispatch(es) should be developed to reasonably test the proposed additions or changes. For example, for an export condition within the study area, the dispatch should model the maximum number of fully loaded generators expected to be in-service unless constrained by the transfer limits of an interface. For an import condition, unit outages simulated within the study area should reflect must-run, spinning reserve and minimum reactive support requirements of system operation. All dispatches are subject to review by the Task Forces.

g. Modeling of Transfer Conditions - Generally, intra-Area transfers will be simulated at or near their established limits (in the direction to produce "worst cases" results) and sensitivities to inter-Area transfers will be determined as appropriate. The rationale for maintaining these transfer levels before and after the addition of the proposed facility should be discussed. The ISO has developed and maintains a list of intra-Area interfaces used in operations.

3.3.1.2 Baseline Performance

Using the supplied and/or modified library case, testing should be conducted to determine pre-addition system performance. This testing will:

- validate the representation of the case used; and
- establish a baseline of performance from which the direct impact of the proposed modification can be demonstrated.

3.3.1.3 Contingency Selection

The applicant should develop a specific list of contingencies that comply with each section of the Reliability Standards which applies, including extreme contingencies. Additional contingency tests, consistent with those standards may be requested by the Task Forces.

3.3.1.4 Tests With A Line Out Of Service

Applications for major changes in transmission or generation facilities should include tests of system performance with selected lines out of service assuming that the area resources and power flows are adjusted between outages. These tests should identify and evaluate potential constraints to future system operation.

3.3.2 Results Reporting

The applicant should provide sufficient details and information to clearly demonstrate system performance under both normal and stressed conditions. This would include:

3.3.2.1 Summary of load flow tests conducted and their results, with and without the proposed modifications, showing at a minimum the following information:
- Load level, generation dispatch and pertinent major interface loadings (both inter-Area and intra-Area);
- Contingencies tested;
- A single summary of lines loaded to 95% or more of their applicable rating;
- Bus voltages outside a range of .95 to 1.05 p.u.;
- Interactions with existing special protection systems; and
- Observed results and related comments, including impact on NPIRs, as appropriate.

3.3.2.2 Summary of results from any other pertinent testing performed such as the analyses described in Section 3.4, Other Testing.

3.3.2.3 One line diagrams showing flows and voltages with and without the proposed changes or additions for the following conditions:
- Normal generation dispatch conditions with all lines in service;
- Stressed generation dispatch conditions with all lines in service; and
- All significant contingency conditions for both normal and stressed generation dispatch cases.

3.3.2.4 Clear, concise narrative interpreting the above results and leading to the conclusion that installation of the subject facility(ies) will have no significant adverse effect on the reliability of the bulk power system as specified in Section I.3.9 of the Tariff. Also, any actions required to mitigate adverse system behavior associated with the proposed facility should be fully documented and explained.

3.3.3 Steady State Evaluations

Evaluations of steady state analyses submitted in support of Proposed Plan Applications will be based on the considerations and expectations described in Section 3.2, Evaluation. Additionally, the two aspects noted below will be of primary concern to the Reliability Committee and its Task Forces during their review.

3.3.3.1 Was the analysis conducted according to generally accepted practice?
- Were assumptions and test conditions as outlined in Section 3.3.1?
- Were tools and procedures applied properly and were they sufficient to provide a complete analysis?

3.3.3.2 Do results of the analysis support the conclusion that the change(s) will: 1) result in no significant adverse effect on the reliability of the bulk power system; and 2) meet the NPIRs? If the analyses indicated any problem areas, how were they resolved?

In particular, the Transmission Task Force will review each analysis to ensure that all of the applicable conditions specified in the Reliability Standards are satisfied. The recommendation of the Transmission Task Force to the Reliability Committee will be based on the applicant having satisfied the applicable conditions required in the Reliability Standards.

## 3.4 Other Testing

Studies demonstrating system performance may occasionally require other testing, in addition to the load flow testing described in Section 3.3 above, to adequately assess the effects of proposed facility changes or additions on the reliability and operating characteristics of the bulk power system. The need for this other testing, such as transient network analysis, short-circuit analysis, and/or reactive power and voltage (Q/V) analysis, depends on the specific project involved. These three analyses, while dealing with dynamic phenomena, do not involve the detailed time simulation of a stability analysis; rather, each is a single snapshot of the ability of the power system to withstand events such as loss of components, short-circuits or unanticipated demand. It is the responsibility of the Governance Participant submitting the Proposed Plan Application to consider the need for these tests when preparing the Proposed Plan supporting analysis and include them as appropriate. The Reliability Committee, its Task Forces, or individual Governance Participants may request any one or more of these other tests or in the course of their review of the supporting analysis may request other testing not described in this guideline. Each Governance Participant that is a Nuclear Plant Generator Operator is expected to have its Reliability Committee representative review the reporting of analysis of a proposed plan and request any additional analysis to address meeting any applicable NPIRs.

### 3.4.1 Transient Network Analysis (TNA)

Transient Network Analysis studies are typically performed as part of the detailed design engineering of a project where there may be concern for transient or temporary overvoltages, voltage flicker, arrester capabilities or insulation coordination. Sudden changes in circuit conditions, such as switching operations, lightning strikes, sudden loss of load or inrush currents (e.g., from a cable, capacitor bank or transformer energization or de-energization) can lead to this type of overvoltage, whose effects are usually confined to an area localized to the switching station. As such, those projects where this would be a concern typically include a TNA study as part of the design process but do not usually include the TNA results as part of the Proposed Plan study.

In those situations where a neighboring Governance Participant is close enough to be affected (typically no more than two busses away from the switching location), the applicant and the other Governance Participant should engage in a joint review of the base case models to be used in the TNA study. Then, in the Proposed Plan study, the applicant should provide sufficient details and information to clearly demonstrate system performance under both normal and stressed conditions. This would normally include a summary of all TNA tests conducted and their results, generally in the form of peak overvoltages or percent voltage change at selected busses and a clear, concise narrative interpreting these results and leading to the conclusion that installation of the subject facility(ies) will have no significant effect on the reliability of the bulk power system as specified in Section I.3.9 of the Tariff. Any actions required to mitigate adverse system behavior associated with the proposed change or addition should be fully documented and explained.

#### 3.4.2 Short-Circuit Analysis

Projects such as the addition of a generator or a transmission element can have a significant impact on the short-circuit duty at substations in the vicinity of the proposed facilities. For those projects where this would be a concern, the applicant should include an analysis of the incremental effects of the project on short-circuit interrupting duty in the vicinity of the proposed change or addition. In those situations where a neighboring Governance Participant is close enough to be significantly affected, the applicant and the other Governance Participant(s) should engage in a joint review of the capabilities of the equipment in the area prior to submission of the Proposed Plan analysis.

In the Proposed Plan study, the applicant should provide sufficient details and information to clearly demonstrate system performance with respect to short-circuits. This would normally include a summary of the short-circuit tests conducted and their results, generally in the form of duty at selected busses, and a clear, concise narrative interpreting these results and leading to the conclusion that installation of the subject facility(ies) will have no significant effect on the reliability of the bulk power system as specified in Section I.3.9 of the Tariff. Any actions required to mitigate adverse system behavior associated with the proposed change or addition should be fully documented and explained.

#### 3.4.3 Q/V Analysis

Voltage and reactive power performance of the bulk power system varies according to the load, transmission and generation in each area. It cannot be predicted system-wide by a single type of facility change or addition. Rather, the impact on the bulk system of a particular change or addition is evidenced by a high sensitivity of voltage at key busses in the system to changes in load, circuit conditions, or reactive compensation. For those projects where this would be a concern, the applicant should include an analysis of the effects of the proposed change or addition on the reactive power and voltage performance of the bulk power system.

In the Proposed Plan study, the applicant should provide sufficient details and information to clearly demonstrate reactive power support and voltage performance under both normal and stressed conditions. This would normally include a summary of all tests conducted and their results, generally in the form of Q/V (or P/V) curves or another measure of reactive power and voltage margin in the affected area and a clear, concise narrative interpreting these results and leading to the conclusion that installation of the subject facility(ies) will have no significant effect on the reliability of the bulk power system as specified in Section I.3.9 of the Tariff. Any actions required to mitigate adverse system behavior associated with the proposed change or addition should be fully documented and explained.

### 3.5 Stability Analysis

It is the responsibility of the Governance Participant submitting a Proposed Plan Application to identify the most severe conditions that can reasonably be expected to exist. It must be demonstrated that under such conditions, the proposed additions or changes will not have any significant adverse impact upon the stability, reliability or operating characteristics of the bulk power system; otherwise, the Governance Participant must propose system modifications, protection systems and/or operating restrictions which will eliminate such adverse impact. Studies demonstrating dynamic performance must then simulate conditions that stress the system beyond "typical" combinations of load level, generation dispatch and power transfers. Further, while the dynamic response of an individual proposed generating unit is of interest, the response of the bulk power system is of primary importance. Since it is necessary for supporting studies to reflect conditions expected to exist at the time of a future system modification, such conditions might include other future facilities with or without Proposed Plan approval that may be installed by about the same point in the future. Upon request, the Stability Task Force will assist the Governance Participant in identifying reasonably stressed conditions for testing.

3.5.1 Conditions to be Tested

3.5.1.1 Assumptions

a. Selection of Year(s) to Model - The initial year chosen for study is normally that of the anticipated system modification. However, the following matters may need to be considered:

- other facilities coming on-line in the same time period; and
- other influences in the area, such as changes in contracts.

The Reliability Committee and its Task Forces will provide guidance in selecting the year and related conditions to be studied.

b. Source of Base Case(s) - The base case(s) should have its origin from the ISO's library of cases, with changes or modifications as provided by the Stability and/or Transmission Task Forces.

c. Other Proposed Facilities - Inclusion of planned or proposed facilities in a study is subject to the status of other Proposed Plan Applications, the System Impact Study queue, and the Subordinate Proposed Plan Application Policy. Consequently each proposed or planned facility must be individually identified in the scope of the study with the aid of the Task Forces and the ISO prior to the start of the study. Having identified the planned or proposed facilities to include in the study, the study can be done with either or both of the following approaches: 1) the facility assumed installed in the base condition with tests determining the sensitivity of system response without the facility, or 2) the facility not installed in the base condition, but with sensitivity tests conducted with the facility included. The Governance Participant conducting the analysis should judge which approach is appropriate for the evaluation.

d. Modeling Devices - Models for devices of particular concern, such as HVdc terminals, are available from the ISO. It is the responsibility of the Proposed Plan applicant to properly represent these devices where appropriate.

e. Load Level - Disturbances should be studied at light load levels since they usually promote more pronounced dynamic response within the New England Control Area than at other load levels. However, other load levels may be of interest in a particular analysis. This should be determined and, as appropriate, additional studies should be conducted.

f. Generation Dispatch - Testing should not be restricted to only typical dispatch; rather the dispatch(es) should be developed to test the proposed modification under stressed conditions. For example, an export condition would be tested by modeling the maximum number of fully loaded generators expected to be in-service in the exporting area unless constrained by the transfer limits of an interface. This will demonstrate if groups of machines in such areas could accelerate and lose synchronism with the bulk power system. At the same time, a "reasonable" number of units should be dispatched within the importing areas. These units need not be fully dispatched but they should reflect must-run, spinning reserve and minimum reactive support requirements of system operation. All dispatches are subject to review by the Task Forces.

g. Modeling of Transfer Conditions - Transfer levels should be selected to produce accentuated dynamic response. Generally, intra-Area transfers will be simulated at or near their established limits (in the direction to produce "worst cases" results) and sensitivities to inter-Area transfers will be determined as appropriate. The rationale for choosing particular interface loadings before and after a modification due to a proposed facility should be discussed. The ISO has developed and maintains a list of interfaces used in operations.

3.5.1.2 Baseline Performance

Using the supplied and/or modified library case, testing should be conducted to validate the representation of the case and dynamics modeling used. If contingency testing indicates a problem, pre-addition testing will be needed to establish a baseline of performance from which the direct impact of the proposed modification can be demonstrated.

3.5.1.3 Contingency Selection

The applicant should develop a specific list of contingencies that comply with each section of the Reliability Standards which applies, including extreme contingencies. Additional contingency tests, consistent with those standards may be requested by the Task Forces. To assist in understanding the selection of contingencies, the applicant should provide a general description of the relay systems at 115 kV stations and above in the vicinity of the proposed change.

3.5.1.4 Tests With A Line Out Of Service

Applications for major changes in transmission or generation facilities should include tests of system performance with selected lines out of service assuming that the area resources and power flows are adjusted between outages. These tests should identify and evaluate potential constraints to future system operation.

3.5.2 Results Reporting

The applicant should provide sufficient details and information to clearly demonstrate system performance under both normal and stressed conditions. This would include:

3.5.2.1 Summary of dynamic tests conducted and their results, with and without the proposed modification, showing at a minimum the following information:
- Load level, generation dispatch and major interface loadings;
- Contingencies tested, with assumed sequence of events and associated times;
- Interactions with existing special protection systems; and
- Observed results and related comments as appropriate.

3.5.2.2 One line diagrams showing at a minimum flows and voltages with and without the proposed modifications for the conditions tested, including:
- Normal generation dispatch conditions with all lines in service;
- Stressed generation dispatch conditions with all lines in service; and
- Conditions tested with lines out of service.

3.5.2.3 Plots demonstrating that stability is maintained in the area of the modification, in other areas of New England and in neighboring systems. Enough information must be provided to demonstrate no other dynamics problems are encountered, such as unacceptable voltage or frequency excursions, undamped oscillations, control system problems, etc.

3.5.2.4 Clear, concise narrative interpreting the above results and leading to the conclusion that installation of the subject facility(ies) will have no significant adverse effect on the reliability of the bulk power system as specified in Section I.3.9 of the Tariff. Also, any actions required to mitigate adverse system behavior associated with the proposed facility should be fully documented and explained.

3.5.3 Stability Evaluations

Evaluations of stability analyses submitted in support of Proposed Plan Applications will be based on the considerations and expectations described in Section 3.2. Additionally, the two aspects noted below will be of primary concern to the Reliability Committee and its Task Forces during their review.

3.5.3.1 Was analysis conducted according to generally accepted practice?
- Were assumptions and test conditions as outlined in Section 3.5.1?
- Were tools and procedures applied properly and were they sufficient to provide a complete analysis?

3.5.3.2 Do results of analysis support conclusion that the change(s) will: 1) result in no significant adverse effect on the reliability of the bulk power system; and 2) meet the NPIRs? If the analyses indicated any problem areas, how were they resolved?

The Stability Task Force will review each analysis to ensure that all of the applicable conditions in the Reliability Standards are satisfied. The recommendation of the Stability Task Force to the Reliability Committee will be based on the applicant having satisfied the applicable conditions required in the Reliability Standards.

## 4.0 Protection Systems and Dynamic Control Systems

Sections 2.6 and 3.3 of PP5-1 indicate the protection system additions/changes for which Proposed Plan Applications are required. These fall into two categories: fault clearing and special protection systems (SPSs).

Proposed Plan Applications for additions/changes in protection systems designed for fault clearing should include assurance that:
- the protection system is designed in accordance with the NPCC Bulk Power System Protection Criteria;
- the associated fault clearing time will not degrade system reliability performance; and
- the NPIRs will be met.

A Level III analysis, as described in Section 3.0, may be needed to demonstrate the effects of increased fault clearing times.

Applications for SPSs require analyses similar to that of a generation or transmission application and the guidelines of Section 3.0 apply. In addition to compliance with the Reliability Standards and NPCC Bulk Power System Protection Criteria, the following factors will be considered in evaluating an application for an SPS:
- Is the SPS initiated by a normal contingency or an extreme contingency?
- How many events trigger the SPS? Are the triggers local or remote?
- What are the monitoring requirements?
- How selective are the triggers (i.e., monitor system parameters vs. breaker contact)?
- Is the response local or remote?
- How many inputs, decisions and actions are involved?
- What is potential for interaction with other SPSs?
- Is the SPS required to control dynamic, voltage or thermal response?
- What actions are taken (load rejection, generation rejection, opening of a transmission line)?
- What is the probability that the SPS will be required to operate?
- What are the implications of inadvertent operation or misoperation (local vs. widespread effects)?

- Operational considerations (operator's view of requirements and constraints).
- Anticipated life of the SPS - is it meant to be temporary or permanent?
- What operating options are available if planning assumptions do not materialize?
- What are modeling requirements; when will they be provided?
- Economic tradeoffs with other alternatives.
- Will the NPIRs be met?

Dynamic control systems such as voltage regulator/exciter systems, power system stabilizers and governors on generators can have a significant effect on the stability, reliability or operating characteristics of the bulk power system. Such dynamic control systems and their attendant effects are to be included in the analyses conducted in support of new generator additions. Effects of changes in dynamic control systems should normally be determined in the course of design studies and a Proposed Plan Application should be submitted if such a change could have a significant effect on the performance of the bulk power system. In such cases, a stability analysis may be requested as outlined in Section 3.5.

## 5.0 Definitions

If appropriate definitions were available from the Reliability Standards they are used in this section. The source of the definition is shown in parenthesis. Following these existing definitions, additional comments are included to assist the reader in interpreting them.

For those cases where no formal definition exists, the one used here is based on a review of existing ISO New England and NPCC documents.

### 5.1 Applicable Emergency Limit

Transmission circuit loading limits have been established for use under both normal and emergency conditions. In general, normal ratings are used for "All lines in" conditions. Under emergency conditions, long term emergency ratings (LTE) may be used for up to one daily load cycle assuming no contingency would cause the loading to go above LTE. Short term emergency ratings (STE) may be used following a system disturbance for up to fifteen minutes. The STE ratings may only be used in situations where the component loading can be reduced below the LTE ratings within fifteen minutes by operator corrective action.

In actual system operations, under emergency conditions, drastic action limits (DAL) may be used where preplanned immediate post contingency actions can reduce loadings below LTE within five minutes. These DAL limits are only used as a last resort during actual system operations. They should not be used in testing the system adequacy in the Proposed Plan Application studies.

Emergency voltage limits have also been established for system operation under emergency conditions. These limits recognize that voltages should not drop below those voltages required for acceptable system stability performance, acceptable operation of generating auxiliaries, acceptable operation of other electrical equipment, operation well above the knee of the voltage curve, and for meeting the NPIRs. Also, the voltage should not rise above the maximum rating of electrical equipment.

5.2 Reasonably Stressed Conditions

Reasonably stressed conditions are those severe load and generation system conditions which have a reasonable probability of actually occurring. Generally both import and export conditions should be addressed. The purpose of testing these conditions is to identify potential weaknesses in the system and not to test the worst imaginable extreme.

5.3 Operating Characteristics

The actual operation of the interconnected system requires that each component of the system must be capable of operating in such a manner as not to adversely affect the system operation. Any additions to the system must be able to operate in such a manner so as not to degrade the present operating flexibility of the system. Operating Characteristics include, but are not limited to: dispatchability, including constraints on economic dispatch, voltage control, flicker, harmonics, black start capability, environmental limitations, maintenance scheduling, TV and radio interference, audible noise, and under frequency load shedding.

5.4 Significant Adverse Effect (Section I.3.9 of the Tariff)

The existing system is designed and operated to meet specific criteria as contained in the various documents referenced through this guideline. After the addition it must be demonstrated that there has been no significant degradation in the level of system performance.

5.5 Normal Dispatch Conditions

Normal Dispatch Conditions refers to the economic dispatch of all New England Control Area generation with appropriate allowance for scheduled maintenance and forced outages. Applicable firm contractual transfers, both purchases and sales, should be included.

5.6 Special Protection Systems (Reliability Standards, Appendix A)

> "A Special Protection System (SPS) is defined as a protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, resource, or system configuration to maintain system stability, acceptable voltages or power flows. Automatic under frequency load shedding, as defined in NPCC Emergency Operation Criteria A-3, is not considered an SPS."

## Document History[1]

Rev. 0 Rec.: RTPC – 1/18/00; App.: PC – 2/4/00
Rev. 1 Rec.: RC – 11/14/00; App.: PC 12/1/00
Rev. 2 Eff.: 2/1/05
Rev. 3 Rec. RC – 2/26/10; Rec.: PC 3/05/10; Eff.: 3/05/10

[1] This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well as revisions to the ISO New England Procedure subsequent to the RTO Operations Date.

Attachment 1
ISO New England Planning Procedure 5-3

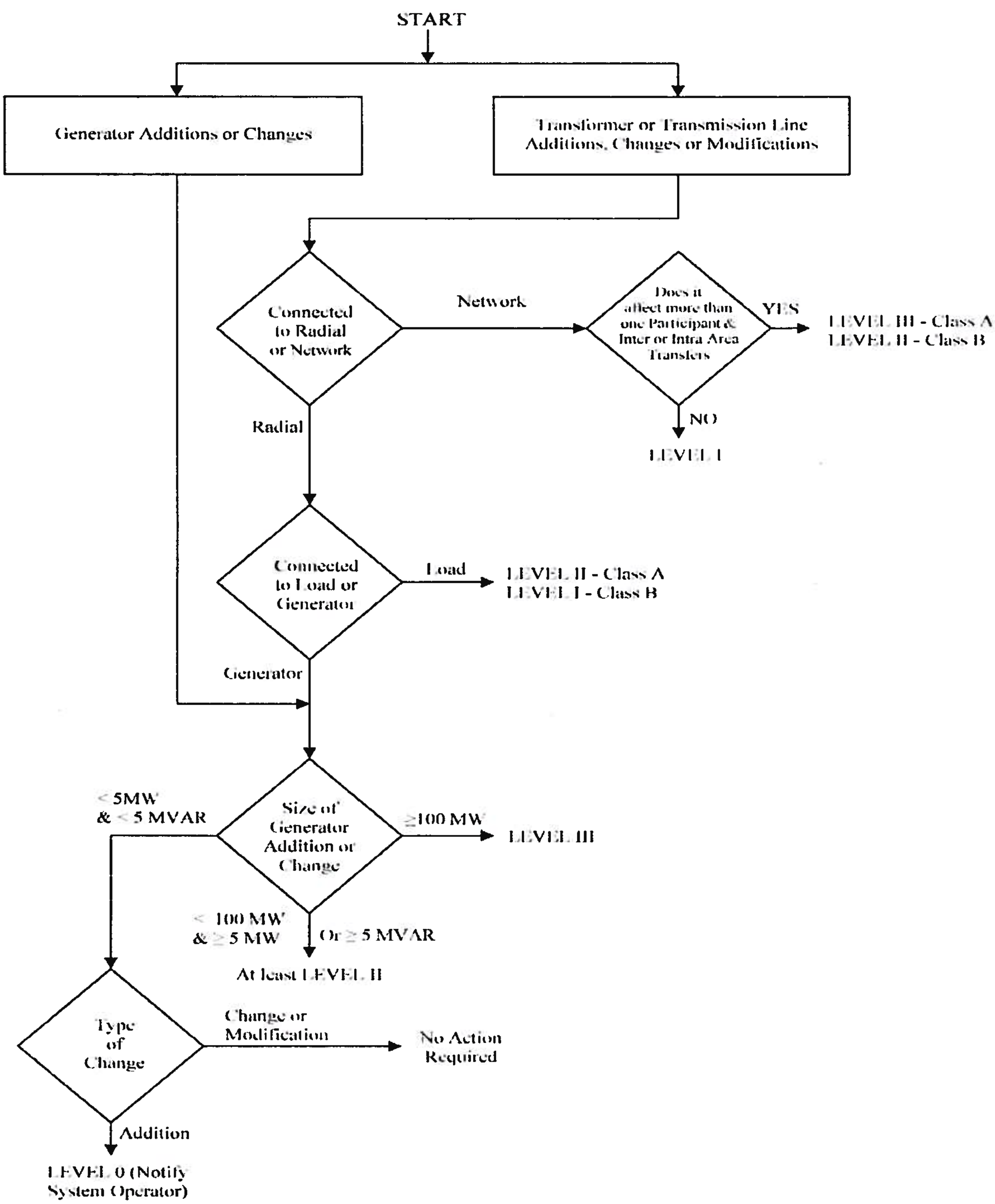
**TABLE 1**
**ITEMS TO DETERMINE LEVEL OF ANALYSIS**

| Item No. | Description | Level of Analysis |
|---|---|---|
| 1. | PTF constructed or rebuilt | |
| | Class A - 230kV and above | See Figure 1 |
| 2. | Non-PTF Transformers or PTF Transformers | |
| | Class A - 345kV/230kV to 69kV and above | See Figure 1 |
| | Class B - 345kV/230kV to below 69kV | See Figure 1 |
| 3. | PTF constructed or rebuilt Transmission Lines | |
| | Class B - Below 230kV to 69kV | See Figure 1 |
| 4. | PTF to PTF Transformers or Non-PTF Transformers | |
| | Class B - 115kV to below 69kV | See Figure 1 |
| 5. | Non-PTF 69kV and above | |
| | Class A - 230kV and above | See Figure 1 |
| | Class B - Below 230kV to 69kV | See Figure 1 |
| 6. | Generation addition or rating change of 5MW or greater or Generator reactive rating change of (+/-) 5 MVAR or greater | See Figure 1 |
| 7. | Generation addition or rating change of less than 5MW and Reactive rating change of less than (+/-) 5 MVAR | |
| | Addition of a new unit (Notify ISO-NE) | Level 0 Proposed Plan Application (See Figure 1) |
| | Modification or change in output rating of an existing unit | No action required |
| 8. | Outside Pool Purchase/Sales | Outside the Scope of Proposed Plan Applications Procedures |
| 9. | Interconnections operating at 69 kV or above with Non-Governance Participants | LEVEL III |
| 10. | Protection Systems - See Planning Procedure No. 5 Section 3.3 & Reliability Standard Appendix A #14 | |
| | Is the System a Special Protection System (SPS)? | YES - LEVEL III<br>NO - To Be Determined By Appropriate Task Force |
| 11. | Other Elements - See Reliability Standard Appendix A #6 | |
| | Shunt Device | LEVEL II |
| | HVDC | LEVEL III |
| | Series Compensation | LEVEL III |
| | Control Devices | To Be Determined by Appropriate Task Force |
| | Circuit Breakers | To Be Determined by Appropriate Task Force |
| | All Others | To Be Determined by Appropriate Task Force |

Attachment 2
ISO New England Planning Procedure 5-3

**FIGURE 1**
**LEVEL OF ANALYSIS FLOW CHART**

(Diagram applies to Items 1-8)



**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-021**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, Attachment A, page 9 (Bates 81): Please have available for review the results from the analyses performed along with an explanation of how those results were used to formulate a long range equipment maintenance plan at PSNH offices in Manchester, NH.

## Response:

Specific to Smagula testimony, Attachment A, page 9, (Bates page 81), PSNH will be prepared to review the results from the analyses performed and a long range equipment maintenance plan with the Staff's consultant.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-022**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, Attachment A, page 11 (Bates 83): Please state if a ride-through option like that used for the interconnection of wind farms to the system is being considered as a potential solution to the overspeed protection problem. If not, please supply the ride-through requirements of wind farms that desire to be interconnected and an explanation why such an approach is invalid in the instant case.

**Response:**
Relay settings are designed to allow ride-through for remote system faults (i.e. those not on the source circuit).

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-023**


**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, Attachment A, page 11 (Bates 83): The studies cited are reactive in nature. What does PSNH require for analyses if proposed changes are to be made in protective equipment settings?

**Response:**
The PSNH Hydro generating units Overspeed Protection Settings Analysis, referenced on bates 83 was reactive in nature, but PSNH determined it was the first step in evaluating how these devices should be set. The analysis has since taken on a more pro-active approach. For example, PSNH Hydro electricians have since reviewed the overspeed circuits to ensure proper wiring configuration to ensure proper event feedback, PSNH continues to install dual overspeed sensing capability (mechanical and electronic), and has installed disturbance monitoring equipment on the high head units (Jackman and Canaan). These efforts will allow PSNH to obtain more data to better understand the events occurring at the generating station that could result in an overspeed condition. If these analyses indicate that a setting change would be appropriate, PSNH Hydro in coordination with PSNH Distribution P&C Engineering would conduct a unit specific overspeed setting analysis to determine the appropriate setting adjustment.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-024**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, Attachment WHS-1, pages Bates 87 – 88: Please explain why the MT-3 breaker installation outages were not incorporated into either unit maintenance outages, the spring transmission outage, or the scrubber tie-in outages.

**Response:**
A new MT-3 breaker was installed in Merrimack Station's high yard during the MK1 fall scrubber tie-in outage (September 6 -25). This required that the Merrimack combustion turbines also be removed from service (September 8 - 22). Transmission completed this new installation to re-route the combustion turbine output through the new breaker. A temporary feed was installed to allow the combustion turbines to be returned to service from September 22 until October 3. The final tie-in of the combustion turbines to the new MT-3 breaker was completed during a short outage October 3 - 7.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-025**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference Smagula testimony, Attachment WHS-1, page Bates 92: Please state if the October 1, 2011 outage for planned switchgear replacement took place in a period that the unit was economic to run. If so, please explain why that time was chosen for the replacement.

## Response:

This 8-hour planned outage on Schiller 6 was during a low-cost energy price period resulting in no replacement power cost. This short outage on October 1, 2011 from 0700 to 1500, was coordinated to be completed at the beginning of the Schiller 4 planned maintenance outage to facilitate the replacement of 480V switchgear on the Unit 4 load center. The Schiller 4 scheduled outage began on October 1.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-026**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:
Reference Smagula testimony, Attachment WHS-1, pages Bates 95 - 103: Please have available for review at PSNH's offices in Manchester, NH the write-ups describing the circumstances surrounding hydro and combustion turbine outages.

## Response:
Specific to Smagula testimony, Attachment WHS-1, Bates pages 95 - 103, PSNH will be prepared to review the circumstances surrounding the hydro and combustion turbine outages with the Staff's consultant.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-027**


**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Reference Smagula testimony, Attachment WHS-2, pages 1 – 11 (Bates 107 – 117): For each outage report, please supply the critical path work during the outage and list other major work performed from the unit backlog list.

**Response:**
Please see the attached table.

| Outage | Critical Path | Other Major Work Completed |
|---|---|---|
| OR-1 MK1 | Boiler tube leak repair | 1)Replaced the slag tank JetPulsion venture and nozzle.<br>2) Replaced couplings the slag tank overflow piping.<br>3) Replaced 1B air heater drive motor.<br>4) Checked 1A and 1B air heater motor couplings<br>5) Water washed both air preheaters.<br>6) Replaced all collector ring brushes.<br>7) Repaired 1C flame detector.<br>8) Brush cleaned North and south side condenser tubes. |
| OR-2 MK2 | Furnace wall tube leak repair | 1) Repaired butterfly valve on #11 hopper in the original precipitator.<br>2) Inspected the inlet cones on 2-A forced draft fan, all looked good.<br>3) Replaced mechanical seal on slag tank fill pump.<br>4) Brush cleaned both sides of the main condenser.<br>5) Cleaned water boxes<br>6) Repaired gas recirc duct floor and metal expansion joint<br>8) Tested middle cooling fan motor on ST2 transformer.<br>9) Inspected, serviced and verified operation of the 200's, 201's, 202's and 207 valves. |
| OR-3 MK2 | 2A condenser pump repair | 1) Installed new spring in PCV-130<br>2) Rebuilt replaced valve and tubing for draft connection purge air<br>3) Brush cleaned both sides of condenser<br>4) Repaired barrel tube leak in B Cyclone<br>5) Inspected furnace, back pass, cyclones, wind-box and gas path ductwork<br>6) Repaired crack and broken strut in the 2A Gas Fan Inlet Duct<br>7) Repaired leak on 2A and 2B secondary steam coils piping.<br>8) Replaced south heat exchanger river outlet valve<br>9) Repaired north heat exchanger river inlet valve operator |
| OR-4 MK2 | Turbine drain pipe weld repair | 1) Replaced and aligned 2-A forced draft fan motor with the spare.<br>2) Tightened packing on the drain valve on the steam supply line inside the screen house.<br>3) Inspected, cleaned and adjusted float and performed operational check on the sump pump west of the condenser (elev. 203).<br>4) Cleaned and inspected the 200 valves.<br>5) Replaced common SCR reagent chemical pump with a new unit.<br>6) Cleaned and inspected the hydraulic coupling fluid drive filter/cooler system.<br>Replaced the lower solenoid valve on 2G ignitor.<br>7) Removed and reinstalled the temperature and vibration pick-ups on the replacement motor for 2-A forced draft fan. |

| | | |
|---|---|---|
| OR-5 NT1 | MBFP - 1B lube oil pump replacement and turning gear inspection and adjustment. | 1) Overhauled screen house hydraulic skid<br>2) Modified circulating water pump bearing lubrication system<br>3) Replaced fuel oil meter<br>4) Replaced scavenging steam valve<br>5) ID fan turning gear maintenance<br>6) Various valve maintenance |
| OR-6 SR5 | Cyclone Pluggage | 1) Condenser vacuum drag line- Replaced two nipples,<br>2) Turbine throttle pilot assembly drain- Replaced and extended drain line,<br>3) Hydrogen dryer trap- rebuilt trap,<br>4) Baghouse #2 module popet valve not closing tight- inspected valve, stroked/adjusted,<br>5) Auxiliary Steam Leak - welded and repaired auxiliary steam supply line,<br>6) Turbine leaking oil on pedestal lock nut cap- Inspected and replaced gaskets<br>7) Aux Steam blocking valve not opening- Changed actuator |
| OR-7 MK2 | Repair of gas recirculation fans | 1) Replaced section of flyash reinjection piping to 2A cyclone<br>2) Repacked economizer hopper upper isolation knife gates<br>3) Installed new power capacitor for 2A circ motor<br>4) Adjusted limit switch for NRV-2 2nd Point Check Valve<br>5) Adjusted limit switch for BW-205 LP-SH Non-return Valve<br>6) Cleaned condenser water boxes<br>7) Addressed leak on Pugmill Gate Valve rebuilt slag tank piston and gate<br>8) Adjusted packing on GRF inlet dampers<br>9) Replaced wall box seals on IK-14 & IK-18 Soot blowers<br>10) Replaced drive hub on 2A Coal Feeder |

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

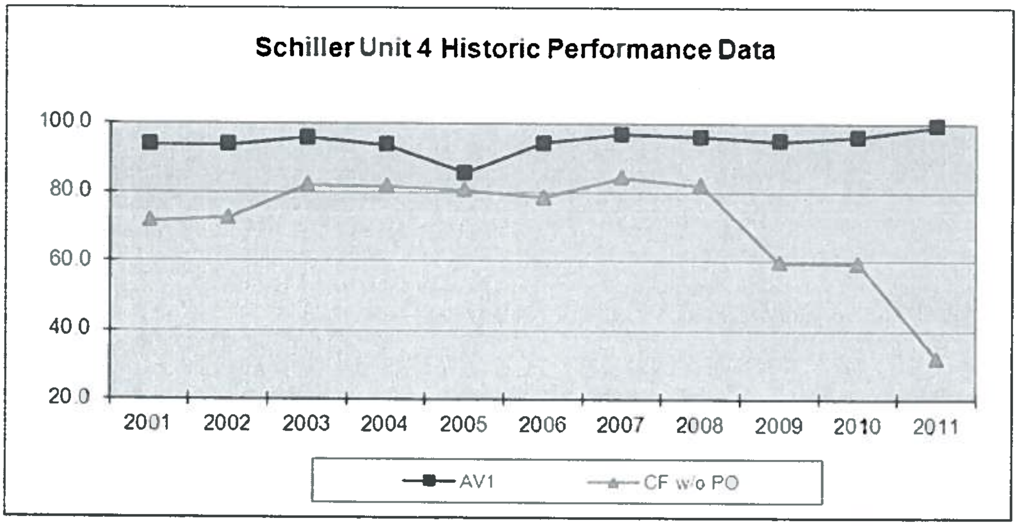
**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-028**
**Page 1 of 2**

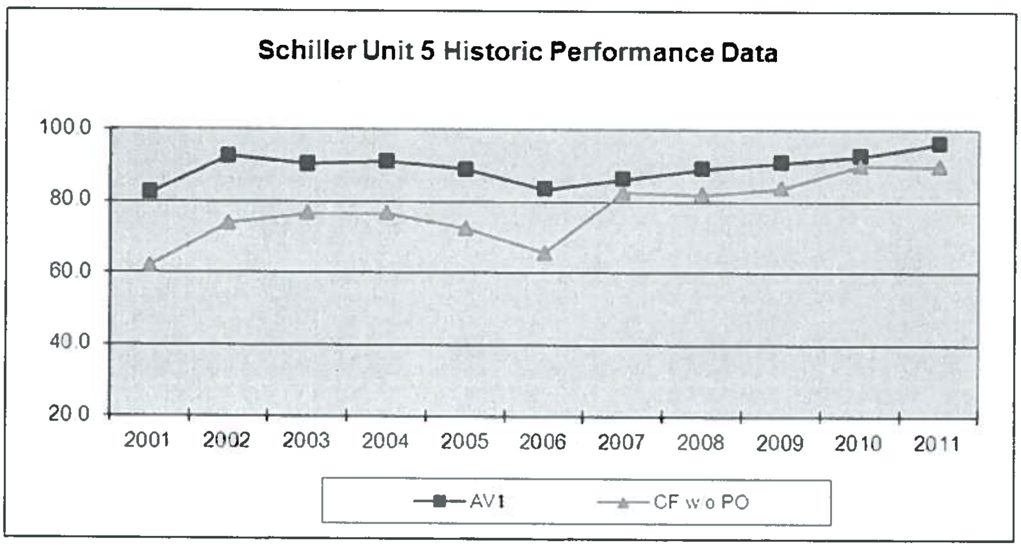
**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

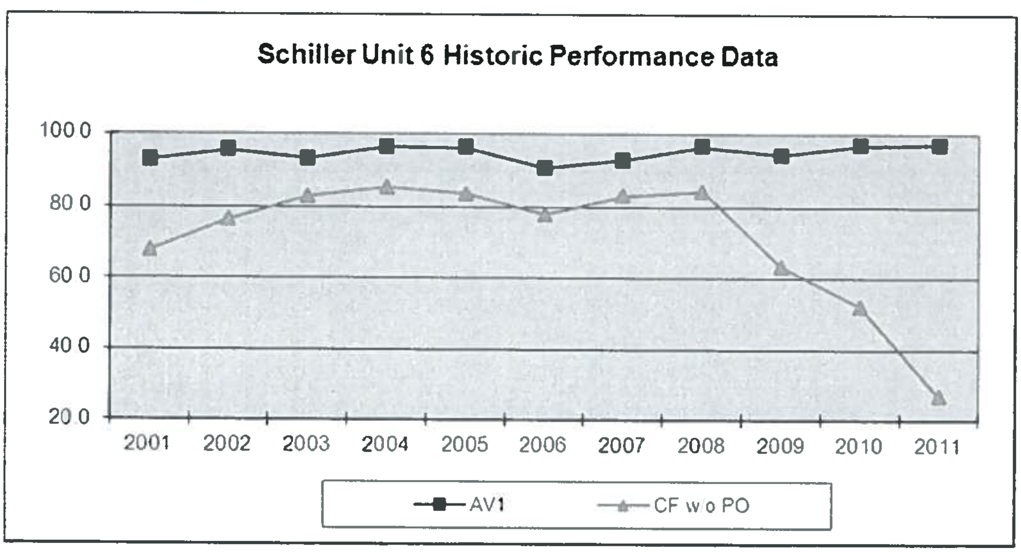
**Question:**
Reference Smagula testimony, Attachment WHS-3, page Bates 124: Please rescale the Schiller 6 graph so that 2011 data is visible.

**Response:**
Attached please find an updated Attachment WHS-3, Bates 124 page with the Schiller 6 graph y-axis rescaled.

# Fossil Plant Graphs – Planned Outages Omitted



**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request STAFF-02**
**Dated: 07/31/2012**
**Q-STAFF-030**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

## Question:

Reference response to Q – STAFF 1-5. It appears that PSNH did not collect approximately $1.4 million excluding the deductible for this outage. Please explain what, if any, non-monetary value PSNH received that would compensate for the decision to accept a $32.5 million settlement.

## Response:

Subsequent to filing a claim for replacement power costs associated with the 2008 Merrimack Unit 2 turbine outage, the insurers and their technical representatives engaged in detailed discussions. These discussions were focused on PSNH's basis for the amount submitted for reimbursement. Factors reviewed included: calendar dates, ISO-NE average daily replacement power values as well as hourly values, actual unit dispatch data, customer load, etc. At the completion of the review of these factors, it was concluded that certain assumptions and calculations initially submitted by PSNH could be interpreted as differing from the intent of the policy language. An adjustment in the amount of $1.4 million resulted in a final reimbursement of $32.5 million, representing the vast majority of PSNH's initial claim. Non-monetary value received from this settlement was in the avoidance of litigation and the associated expenses, as well as avoidance of additional time and expense in performing further analyses and administration of the claim.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request OCA-02**
**Dated: 07/31/2012**
**Q-OCA-002**


**Witness:** **Robert A. Baumann**
**Request from:** **Office of Consumer Advocate**

**Question:**
Reference response to OCA 1-8. The response includes "ISO Schedule 2 and load response expense" in the amount 2,473[,000]. Please provide a description of "ISO Schedule 2 and load response expense" and explain why the Company includes these expenses here in the Working Capital calculation.

**Response:**
ISO Schedule 2 is a service provided by ISO New England to administer the Energy Market. These ISO Schedule 2 expenses are paid to ISO for administration of the core operation of the Energy Market, generation dispatch and energy accounting. ISO Load Response Program expenses consist of demand response agreements with retail customers to encourage them to reduce their electricity consumption during periods of peak demand. Demand response expenses are allocated pro rata based upon network load to any network customer that designates load for Regional Network Service.

The ISO expenses charged to PSNH are not energy expenses but are administrative in nature. As a result, these ISO charges are included in the Operation and Maintenance expenses that are reflected in the Working Capital calculation.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request OCA-02**
**Dated: 07/31/2012**
**Q-OCA-005**
**Page 1 of 1**

**Witness:** **Jody J. TenBrock**
**Request from:** **Office of Consumer Advocate**

**Question:**
Reference response to TC 1-2. The response uses the term "residual oil." Does this term refer to both #2 and #6 oil inventory? Please explain.

**Response:**

The term "#6 oil" is residual fuel oil, which is burned for generation in the main boiler at Newington Station. Diesel fuel oil is referred to as "#2 oil."

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request OCA-02**
**Dated: 07/31/2012**
**Q-OCA-006**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **Office of Consumer Advocate**

## Question:

Reference response to TC 1-26. Please provide definitions for the variables in the equation provided and the numerical values relative to Newington Station in 2011 which, when used in the equation provided, result in an EAF of 93.6%. That is, please provide the values of: 1) Available Hours; 2) Equivalent Unit Derated Hours and; 3) Period Hours.

## Response:

Below are the definitions for the variables listed consistent with the NERC generating availability data system.

**Available Hours** (AH) - The sum of the Unit Service Hours, Reserve Shutdown Hours, Pumping Hours (if applicable), and Synchronous Condensing Hours (if applicable)
**Equivalent Derated Hours** (EDH) - The sum of Equivalent Planned Derate Hours, Equivalent Unplanned Derate Hours and Equivalent Seasonal Derate Hours.
**Period Hours** (PH) - Number of hours in the period being reported that the unit was in the active state.

Newington's EAF of 93.6%, as provided in the May 1 filing, is shown below. Please note that Newington's EAF has been revised and the updated calculation of 94.3% is shown below.

**2011 Newington Station EAF Calculation** (as reported)

AH = 8304 Hours
EDH =99.32 Hours
PH = 8760 Hours

EAF = (8304 hrs -99.32 hrs) x 100 ÷ 8760 hrs
EAF = 93.6%

**2011 Newington Station EAF Calculation** (revised)

AH = 8304 Hours
EDH = 39.32 Hours
PH = 8760 Hours

EAF = (8304 hrs - 39.32 hrs) x 100 ÷ 8760 hrs
EAF = 94.3%

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-02**
**Dated: 07/31/2012**
**Q-TC-001**
**Page 1 of 4**

**Witness:** **Frederick White, William H. Smagula**
**Request from:** **TransCanada**

**Question:**

Reference the PSNH response to TC 1-34 in this docket.

i.) How does PSNH determine when the Newington unit "is dispatched to serve the NE-Pool and not PSNH customer load?".

ii.) What is the financial significance to PSNH customers whether the Newington unit is dispatched to serve NEPOOL load or PSNH customer load?

iii.) What is the numerical value of the margin used in 2011 "that is designed to offset maintenance costs"?

iv.) In 2011, what were the numerical values used that represented "the projected replacement oil cost" and on what specific days of operation were these values applied?

**Response:**

i) Based on forecasted load, and with Newington often dispatched as the marginal unit (i.e. – the last PSNH unit dispatched in merit order), there is an expectation of whether Newington's output will offset ES load or be surplus to ES load.

ii) When dispatched to serve ISO-NE load market revenues in excess of dispatch costs benefit ES customers. When dispatched to serve ES load customers bear dispatch costs rather than wholesale market energy costs.

iii) The value varies based on unit status and expected potential maintenance associated with expected operating requirements.

iv) Refer to FBW-4 in filed testimony (Bates page 60) for representative daily replacement oil costs. Backup data is included in the attached file. Oil prices are at NY Harbor and do not include delivery basis to New England. The values are applied on a daily basis in unit offer prices to ISO-NE because oil is required for operation above 310 MW.

| Date | No. 6 Oil NY Harbor $/MMBtu |
|---|---|
| 01/03/2011 | 12.478 |
| 01/04/2011 | 12.367 |
| 01/05/2011 | 12.613 |
| 01/06/2011 | 12.467 |
| 01/07/2011 | 12.327 |
| 01/10/2011 | 12.562 |
| 01/11/2011 | 12.706 |
| 01/12/2011 | 12.725 |
| 01/13/2011 | 12.621 |
| 01/14/2011 | 12.741 |
| 01/17/2011 | 12.669 |
| 01/18/2011 | 12.597 |
| 01/19/2011 | 12.569 |
| 01/20/2011 | 12.410 |
| 01/21/2011 | 12.497 |
| 01/24/2011 | 12.486 |
| 01/25/2011 | 12.327 |
| 01/26/2011 | 12.690 |
| 01/27/2011 | 12.632 |
| 01/28/2011 | 12.939 |
| 01/31/2011 | 13.278 |
| 02/01/2011 | 13.393 |
| 02/02/2011 | 13.549 |
| 02/03/2011 | 13.564 |
| 02/04/2011 | 13.461 |
| 02/07/2011 | 13.460 |
| 02/08/2011 | 13.592 |
| 02/09/2011 | 13.843 |
| 02/10/2011 | 13.724 |
| 02/11/2011 | 13.862 |
| 02/14/2011 | 14.007 |
| 02/15/2011 | 14.153 |
| 02/16/2011 | 14.323 |
| 02/17/2011 | 14.183 |
| 02/18/2011 | 14.199 |
| 02/22/2011 | 14.657 |
| 02/23/2011 | 15.357 |
| 02/24/2011 | 15.297 |
| 02/25/2011 | 15.274 |
| 02/28/2011 | 15.209 |
| 03/01/2011 | 15.457 |
| 03/02/2011 | 15.551 |
| 03/03/2011 | 15.497 |
| 03/04/2011 | 15.694 |
| 03/07/2011 | 15.898 |
| 03/08/2011 | 15.718 |
| 03/09/2011 | 16.086 |
| 03/10/2011 | 16.017 |
| 03/11/2011 | 16.338 |
| 03/14/2011 | 16.863 |
| 03/15/2011 | 15.656 |
| 03/16/2011 | 15.620 |
| 03/17/2011 | 15.950 |
| 03/18/2011 | 15.909 |
| 03/21/2011 | 16.073 |
| 03/22/2011 | 16.331 |
| 03/23/2011 | 16.275 |
| 03/24/2011 | 16.280 |
| 03/25/2011 | 16.307 |
| 03/28/2011 | 16.226 |
| 03/29/2011 | 16.105 |
| 03/30/2011 | 16.001 |
| 03/31/2011 | 16.420 |
| 04/01/2011 | 16.753 |
| 04/04/2011 | 17.086 |
| 04/05/2011 | 17.226 |
| 04/06/2011 | 17.237 |
| 04/07/2011 | 17.317 |
| 04/08/2011 | 17.619 |
| 04/11/2011 | 17.309 |
| 04/12/2011 | 17.045 |
| 04/13/2011 | 17.261 |
| 04/14/2011 | 17.205 |
| 04/15/2011 | 17.390 |
| 04/18/2011 | 17.104 |
| 04/19/2011 | 16.935 |
| 04/20/2011 | 17.174 |
| 04/21/2011 | 17.059 |
| 04/25/2011 | 17.032 |
| 04/26/2011 | 17.019 |
| 04/27/2011 | 17.127 |
| 04/28/2011 | 17.014 |

| | |
|---|---|
| 04/29/2011 | 17.080 |
| 05/02/2011 | 17.019 |
| 05/03/2011 | 16.833 |
| 05/04/2011 | 16.884 |
| 05/05/2011 | 15.647 |
| 05/06/2011 | 15.472 |
| 05/09/2011 | 15.973 |
| 05/10/2011 | 16.084 |
| 05/11/2011 | 15.484 |
| 05/12/2011 | 15.540 |
| 05/13/2011 | 15.635 |
| 05/16/2011 | 15.410 |
| 05/17/2011 | 15.293 |
| 05/18/2011 | 15.620 |
| 05/19/2011 | 15.553 |
| 05/20/2011 | 15.627 |
| 05/23/2011 | 15.384 |
| 05/24/2011 | 15.747 |
| 05/25/2011 | 16.028 |
| 05/26/2011 | 16.033 |
| 05/27/2011 | 16.060 |
| 05/31/2011 | 16.429 |
| 06/01/2011 | 16.165 |
| 06/02/2011 | 16.423 |
| 06/03/2011 | 16.563 |
| 06/06/2011 | 16.517 |
| 06/07/2011 | 16.892 |
| 06/08/2011 | 17.083 |
| 06/09/2011 | 17.290 |
| 06/10/2011 | 17.215 |
| 06/13/2011 | 17.245 |
| 06/14/2011 | 17.294 |
| 06/15/2011 | 16.467 |
| 06/16/2011 | 16.556 |
| 06/17/2011 | 16.498 |
| 06/20/2011 | 16.455 |
| 06/21/2011 | 16.428 |
| 06/22/2011 | 16.754 |
| 06/23/2011 | 15.954 |
| 06/24/2011 | 15.958 |
| 06/27/2011 | 15.938 |
| 06/28/2011 | 16.291 |
| 06/29/2011 | 16.828 |
| 06/30/2011 | 16.855 |
| 07/01/2011 | 16.542 |
| 07/05/2011 | 16.661 |
| 07/06/2011 | 16.614 |
| 07/07/2011 | 17.064 |
| 07/08/2011 | 16.903 |
| 07/11/2011 | 16.847 |
| 07/12/2011 | 16.984 |
| 07/13/2011 | 17.064 |
| 07/14/2011 | 16.913 |
| 07/15/2011 | 17.040 |
| 07/18/2011 | 16.884 |
| 07/19/2011 | 16.847 |
| 07/20/2011 | 17.070 |
| 07/21/2011 | 17.030 |
| 07/22/2011 | 17.158 |
| 07/25/2011 | 16.976 |
| 07/26/2011 | 16.976 |
| 07/27/2011 | 16.833 |
| 07/28/2011 | 16.824 |
| 07/29/2011 | 16.641 |
| 08/01/2011 | 16.733 |
| 08/02/2011 | 16.618 |
| 08/03/2011 | 16.203 |
| 08/04/2011 | 15.481 |
| 08/05/2011 | 15.683 |
| 08/08/2011 | 15.079 |
| 08/09/2011 | 14.835 |
| 08/10/2011 | 15.177 |
| 08/11/2011 | 15.217 |
| 08/12/2011 | 15.225 |
| 08/15/2011 | 15.604 |
| 08/16/2011 | 15.647 |
| 08/17/2011 | 15.812 |
| 08/18/2011 | 15.309 |
| 08/19/2011 | 15.503 |
| 08/22/2011 | 15.513 |
| 08/23/2011 | 15.709 |
| 08/24/2011 | 15.845 |
| 08/25/2011 | 15.890 |
| 08/26/2011 | 15.942 |
| 08/29/2011 | 15.993 |

| | |
|---|---|
| 08/30/2011 | 16.251 |
| 08/31/2011 | 16.272 |
| 09/01/2011 | 16.149 |
| 09/02/2011 | 15.774 |
| 09/06/2011 | 15.868 |
| 09/07/2011 | 16.300 |
| 09/08/2011 | 16.125 |
| 09/09/2011 | 15.760 |
| 09/12/2011 | 15.616 |
| 09/13/2011 | 15.592 |
| 09/14/2011 | 15.672 |
| 09/15/2011 | 16.089 |
| 09/16/2011 | 16.060 |
| 09/19/2011 | 15.839 |
| 09/20/2011 | 15.949 |
| 09/21/2011 | 15.890 |
| 09/22/2011 | 15.114 |
| 09/23/2011 | 15.028 |
| 09/26/2011 | 15.002 |
| 09/27/2011 | 15.413 |
| 09/28/2011 | 15.293 |
| 09/29/2011 | 15.352 |
| 09/30/2011 | 15.098 |
| 10/03/2011 | 14.800 |
| 10/04/2011 | 14.525 |
| 10/05/2011 | 14.932 |
| 10/06/2011 | 15.425 |
| 10/07/2011 | 15.386 |
| 10/10/2011 | 15.767 |
| 10/11/2011 | 15.933 |
| 10/12/2011 | 16.076 |
| 10/13/2011 | 15.885 |
| 10/14/2011 | 16.165 |
| 10/17/2011 | 15.882 |
| 10/18/2011 | 15.974 |
| 10/19/2011 | 15.640 |
| 10/20/2011 | 15.826 |
| 10/21/2011 | 15.790 |
| 10/24/2011 | 16.025 |
| 10/25/2011 | 15.898 |
| 10/26/2011 | 15.758 |
| 10/27/2011 | 16.133 |
| 10/28/2011 | 16.009 |
| 11/04/2011 | 16.300 |
| 11/08/2011 | 16.809 |
| 11/09/2011 | 16.539 |
| 11/10/2011 | 16.634 |
| 11/11/2011 | 16.725 |
| 11/14/2011 | 16.515 |
| 11/15/2011 | 16.606 |
| 11/16/2011 | 16.505 |
| 11/17/2011 | 15.826 |
| 11/18/2011 | 15.599 |
| 11/21/2011 | 15.386 |
| 11/22/2011 | 15.704 |
| 11/23/2011 | 15.524 |
| 11/25/2011 | 15.472 |
| 11/28/2011 | 15.882 |
| 11/29/2011 | 16.141 |
| 11/30/2011 | 16.057 |
| 12/01/2011 | 15.869 |
| 12/02/2011 | 15.981 |
| 12/05/2011 | 16.052 |
| 12/06/2011 | 16.108 |
| 12/07/2011 | 15.850 |
| 12/08/2011 | 15.720 |
| 12/09/2011 | 15.823 |
| 12/12/2011 | 15.715 |
| 12/13/2011 | 15.965 |
| 12/14/2011 | 15.235 |
| 12/15/2011 | 15.190 |
| 12/16/2011 | 15.174 |
| 12/19/2011 | 15.222 |
| 12/20/2011 | 15.678 |
| 12/21/2011 | 15.756 |
| 12/22/2011 | 15.752 |
| 12/23/2011 | 15.744 |
| 12/27/2011 | 15.933 |
| 12/28/2011 | 15.771 |
| 12/29/2011 | 15.831 |
| 12/30/2011 | 15.818 |

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-02**
**Dated: 07/31/2012**
**Q-TC-002**


**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

**Question:**
Reference the PSNH response to TC 1-35 in this docket, what month and year were each of the four efforts described in the response performed?

**Response:**
These activities involved efforts that were not completed in a single month; that said, timing associated with each of the different activities is provided below in *italics*.

Feasibility Determination - Determine the feasibility of conducting a fuel oil transfer from the Newington inventory to a vessel at the PSNH dock. PSNH initiated an engineering study of the existing system which was completed by an outside engineering firm experienced with piping systems and fuel oil transfer. The intent of this study was to determine if the existing fuel oil transfer system was capable of completing such an operation and if any modifications were necessary. It was ultimately determined that a fuel oil transfer from the Newington inventory could be completed safely and with no impact to the environment. The final engineering report provided by this engineering firm did recommend, as a precautionary measure, that an upgraded check valve be located on the dock at the inlet to the oil transfer hose manifold. *Timing: As stated in prior data requests, PSNH began to evaluate the practicality of safely physically moving residual oil from its Newington Station tanks back into barges in order to sell the oil into the market in an effort to reduce its inventory levels in 2010. Specifically, the study was initiated in November of 2010 and completed in April of 2011.*

Engineering, Procurement and Installation - Procure and install the new check valve recommended by the engineering firm. *Timing: The recommended check valve was ordered in March of 2011 and installed in August of 2011.* In addition to the recommendation for the upgraded check valve provided by the engineering firm, PSNH opted to use a dedicated and trained crew of employees to execute the oil transfer procedure and install additional control measures which included strategically located emergency stop buttons to shut down the oil transfer pumps. *Timing: Initiated March of 2012 and completed April 2012.* These stop buttons were installed on the dock so in the event of a malfunction, the oil transfer pumps could be shut down immediately. *Timing: Initiated in December 2011 and completed February 2012.*

Update and Approval of Procedures - Develop a fuel oil transfer procedure which was completed by PSNH in collaboration with a Person In Charge (PIC) certified marine service consultant specializing in fuel oil transfer. The procedure was then submitted to the US Coast Guard (USCG) for approval. In addition to the fuel oil transfer procedure, the USCG required the Terminal Operators Manual be modified to reflect this type of operation. The updated manual was also submitted to the US EPA as required under the emergency response Integrated Contingency Plan (ICP) for approval. Upon approval of the updated plans and procedures the fuel oil transfer could occur. *Timing: Initiated in March of 2011 and completed April 2012.*

Execution of Off-loading - Implementation of oil off-loading to an empty vessel which included proper execution of the USCG approved fuel oil transfer procedure. *Timing: First transfer completed April of 2012 and second transfer completed May of 2012.*

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-02**
**Dated: 07/31/2012**
**Q-TC-006**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **TransCanada**

## Question:

Reference the PSNH response to TC 1-11 in this docket, please explain in detail how PSNH evaluated the economics of its generation versus purchase alternatives during 2011 or prior to 2011 to the extent that it had an impact on the price of power that was used during 2011.

## Response:

PSNH evaluates expected economic operation of its units by comparing dispatch costs to forward electricity market prices, which leads to a determination of need for supplemental purchases to serve forecasted ES energy requirements. If expected economic operation of its units is sufficient to meet requirements supplemental purchases are not required; if not, purchase alternatives are evaluated. PSNH performs these evaluations regularly over long term and short term horizons in support of ES and generation operations planning. In 2011, two 50 MW annual peak purchases were transacted in 2008. All other purchases during 2011 were transacted in 2011, within a week of delivery. Exhibits FBW-2 & 3 also provide pertinent information.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-02**
**Dated: 07/31/2012**
**Q-TC-007**
**Page 1 of 1**

**Witness:** **Frederick White, William H. Smagula**
**Request from:** **TransCanada**

**Question:**
Reference the PSNH response to TC 1-28 in this docket, please provide PSNH electricity demand figures for the years 2006, 2007, 2008, 2009, 2010 and 2011.

**Response:**

| Year | PSNH Sales MWh |
|---|---|
| 2005 | 8,171,858 |
| 2006 | 8,029,899 |
| 2007 | 8,136,536 |
| 2008 | 7,970,949 |
| 2009 | 7,657,471 |
| 2010 | 7,860,713 |
| 2011 | 7,823,872 |

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-02**
**Dated: 07/31/2012**
**Q-TC-008**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **TransCanada**

**Question:**
Reference the PSNH response to TC 1-30 in this docket, please provide the number of total unit startups for Newington Unit 1 for the years 2006, 2007, 2008, 2009 and 2010.

**Response:**
Below is listed the number of starts for Newington 1 each year as shown.

| Year | Number of starts |
|---|---|
| 2006 | 85 |
| 2007 | 39 |
| 2008 | 23 |
| 2009 | 39 |
| 2010 | 123 |

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-02**
**Dated: 07/31/2012**
**Q-TC-010**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **TransCanada**

**Question:**
Reference the PSNH response to TC 1-12 in this docket, please provide the percentage equivalent for 2011 that equates to the 2,862,519 MWh response for 2011 in TC 1-13.

**Response:**
The percentage equivalent is 52%.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Data Request TC-02**
**Dated: 07/31/2012**
**Q-TC-011**
**Page 1 of 1**

**Witness:** **Frederick White**
**Request from:** **TransCanada**

## Question:

Reference the PSNH response to TC 1-33 in this docket, please clarify that it can be assumed that the period under discussion and the relationship of PSNH's generation versus purchase alternatives now applies similarly to all of its generation assets.

## Response:

Supplemental purchase requirements are and always have been dependent upon the relative economics of all of PSNH's generation resources versus forward electricity market purchase alternatives.

**Witness:** William H. Smagula
**Request from:** New Hampshire Public Utilities Commission Staff

**Question:**
Please provide a schedule for completion of the study to be performed for Recommendation 5 in Mr. Smagula's testimony.

**Response:**
As described in Commission Order No. 25,321 issued January 26, 2012 in Docket No. DE 11-094, PSNH agreed to acquire the in-house capability to conduct transient stability analyses. More specifically, in Exhibit 6 in that docket provided, in part:

> "PSNH agrees to develop the in-house expertise to identify planned changes in the distribution system which have the likelihood to create a transient instability event at PSNH's hydroelectric generating stations. In house knowledge will begin to be developed in January. PSNH distribution and generation personnel will begin to meet on at least a quarterly basis, beginning the first quarter of 2012, to identify and discuss potential impacts of distribution system changes on the performance of PSNH's hydroelectric generating stations including a review of the benefits, potential risks and costs. As feasible, modeling for hydro facilities with higher risk for instability will be prioritized. As deemed appropriate, PSNH will have a transient stability study performed either by in-house engineers or by an outside consulting firm. With this approach, PSNH hopes to minimize cost to customers while maximizing value and reducing risk."

As noted in the response to STAFF-02, Q-STAFF-019, and in Mr. Smagula's testimony, PSNH has extended transient stability training to a Senior Engineer in the System Planning & Strategy department. Development of expertise will be a time-intensive and iterative process.

In 2012 to date, no system changes have been identified that may affect the performance of PSNH's hydroelectric generating stations. PSNH does have plans, even without changes to the system that may affect generating station performance, to perform transient stability analysis for Canaan and Jackman.

PSNH is in the process of gathering generator data for Canaan and Jackman hydro units. PSNH is also beginning to develop the models which will be used to conduct the stability studies. We anticipate that the model development will be quite time consuming for these first studies due to the learning curve associated with performing stability studies for the first time. Also, there is an additional learning curve because the training that was available was designed for use on a more recent version of the software than is used by the ISO and NU.

The steps necessary to complete these two stability studies will include: 1) gathering the necessary generator data; 2) developing a working model and determining the appropriate scope of distribution assets which should be incorporated in the model; 3) determining the remote fault scenarios and running each case; and 4) determining the validity of the results. We expect that this will be an iterative process as we gain experience. While we do not as of yet have the experience to accurately predict how long this process will take, we expect that one of these studies will be completed by year end. The senior engineer assigned these studies is not a dedicated resource to this project only.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Technical Session TS-01**
**Dated: 09/06/2012**
**Q-TECH-002**


**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
What is the total amount of oil that can be stored in inventory at Newington?

**Response:**
Newington Station has four bulk fuel oil storage tanks that have a combined working capacity of 730,000 barrels. Newington Station utilizes the deep water marine terminal located across the street at PSNH's Schiller Station in Portsmouth, New Hampshire, for the receipt of No. 6 fuel oil. The terminal can accommodate ships carrying up to 250,000 barrels (10.5 million gallons) of oil as well as barges carrying lesser amounts. A piping system interconnects all four tanks, which allows for oil transfer and blending. Fuel oil is transferred on a daily or as needed basis to the Newington on-site day tank, where it is used in Newington's boiler. At full load on oil only, Newington Station would use about 17,000 barrels of oil per day. The capacity of the four oil storage tanks is sufficient to sustain Newington Station's operations at full load operation mode for a maximum of 50 days.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Technical Session TS-01**
**Dated: 09/06/2012**
**Q-TECH-005**


**Witness:** **Frederick White**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Re: Staff-01, Q-Staff-009, please provide the same table with updated information based on the filing made for the ES rate for the second half of 2011.

**Response:**
Please see the attached table for the requested data.
Some notes on changes for the Jul-Dec period - Forecasted prices for the Jul-Dec, 2011 period in the December, 2010 and June, 2011 ES filings are shown below. Prices for electricity and natural gas increased between the two filings which is the primary explanation for the decrease in modeled economic reserve shutdown hours.

| | Forecast Prices for July-December, 2011 | |
|---|---|---|
| Product | December, 2010 Filing | June, 2011 Filing |
| 7x24 MA Hub LMP - $/MWh | 46.1 | 49.4 |
| Natural Gas Deliv. to NE - $/MMBtu | 4.985 | 5.260 |

Additionally, a change to the Schiller 4 outage schedule in October reclassified 353 economic reserve shutdown hours as outage hours, and therefore those hours are not shown in the attached updated table.

## 2011 - Economic Reserve Shutdown Hours

| | Merrimack 1 | | | Merrimack 2 | | | Schiller 4 | | | Schiller 5 | | | Schiller 6 | | | Newington | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Economic Reserve Shutdown Hours | | | Economic Reserve Shutdown Hours | | | Economic Reserve Shutdown Hours | | | Economic Reserve Shutdown Hours | | | Economic Reserve Shutdown Hours | | | Economic Reserve Shutdown Hours | |
| 2011 | MWh/Hr | Modeled | Actual | MWh/Hr | Modeled | Actual | MWh/Hr | Modeled | Actual | MWh/Hr | Modeled | Actual | MWh/Hr | Modeled | Actual | MWh/Hr | Modeled | Actual |
| Jan | 114.0 | 0 | 4 | 343.0 | 0 | 0 | 48.0 | 0 | 141 | 42.6 | 0 | 0 | 48.6 | 0 | 27 | 400.2 | 694 | 460 |
| Feb | 114.0 | 0 | 0 | 343.0 | 0 | 0 | 48.0 | 0 | 0 | 42.6 | 0 | 0 | 48.6 | 0 | 0 | 400.2 | 644 | 560 |
| Mar | 114.0 | 0 | 0 | 343.0 | 0 | 18 | 48.0 | 0 | 71 | 42.6 | 0 | 0 | 48.6 | 0 | 14 | 400.2 | 594 | 590 |
| Apr | 114.0 | 0 | 0 | 343.0 | 0 | 62 | 48.0 | 0 | 256 | 42.6 | 0 | 0 | 48.6 | 0 | 0 | 400.2 | 474 | 493 |
| May | 114.0 | 377 | 53 | 343.0 | 0 | 572 | 48.0 | 744 | 140 | 42.6 | 0 | 0 | 48.6 | 744 | 335 | 400.2 | 744 | 744 |
| Jun | 112.5 | 0 | 445 | 338.4 | 0 | 0 | 47.5 | 0 | 592 | 43.1 | 0 | 0 | 47.9 | 0 | 666 | 400.2 | 692 | 710 |
| Jul | 112.5 | 0 | 258 | 338.4 | 0 | 0 | 47.5 | 0 | 438 | 43.1 | 0 | 0 | 47.9 | 0 | 336 | 400.2 | 640 | 605 |
| Aug | 112.5 | 0 | 0 | 338.4 | 0 | 323 | 47.5 | 0 | 645 | 43.1 | 0 | 0 | 47.9 | 0 | 658 | 400.2 | 670 | 695 |
| Sep | 112.5 | 0 | 0 | 338.4 | 0 | 720 | 47.5 | 0 | 582 | 43.1 | 0 | 0 | 47.9 | 0 | 587 | 400.2 | 720 | 628 |
| Oct | 114.0 | 0 | 192 | 343.0 | 0 | 277 | 48.0 | 0 | 1 | 42.6 | 0 | 0 | 48.6 | 0 | 617 | 400.2 | 744 | 590 |
| Nov | 114.0 | 0 | 0 | 343.0 | 0 | 0 | 48.0 | 0 | 438 | 42.6 | 0 | 0 | 48.6 | 0 | 709 | 400.2 | 720 | 656 |
| Dec | 114.0 | 0 | 0 | 343.0 | 0 | 359 | 48.0 | 0 | 744 | 42.6 | 0 | 0 | 48.6 | 0 | 733 | 400.2 | 686 | 744 |
| Total | 113.5 | 377 | 952 | 341.5 | 0 | 2,331 | 47.8 | 744 | 4,048 | 42.8 | 0 | 0 | 48.4 | 744 | 4,682 | 400.2 | 8,022 | 7,475 |

'Modeled' figures for Jan-Jun and Jul-Dec periods, are from the December, 2010 and June, 2011 ES rate filings, respectively.

Public Service Company of New Hampshire
Docket No. DE 12-116

Technical Session TS-01
Dated: 09/06/2012
Q-TECH-006


Witness: William H. Smagula
Request from: New Hampshire Public Utilities Commission Staff

**Question:**
Re: Staff-02, Q-Staff-010, please provide more detail on the decision-making process for the installation of the recirculation ducts and the alternatives considered. What would have been the impact to the Fall 2011 Merrimack 1 outage had the recirculation ducts been installed at that time? What would have been the impact to the subsequent 9-day outage?

**Response:**
As background, Merrimack Station Units 1 and 2 are pressurized furnaces. The units each have forced draft fans (FD fans) which push preheated combustion air into the boiler, through the pollution control equipment and out the chimney. With added pollution control equipment over the last 20 years, there is little to no additional margin for the existing forced draft fans to push the air through the new scrubber equipment and out the new combined stack. Therefore, the new scrubber system was designed with booster fans which are needed to push the combustion air through the new scrubber duct work, through the absorber vessel, and out the new common stack. The design criteria for the new booster fans included a wide range of operation from a very clean, single unit on-line to a worst case scenario when both units are operating and the boilers have a build up of ash, as is the situation if the units have been in operation for many months. Note that after extended operations, boiler ash will build up and cause restrictions or added pressure drop in the boiler. This additional ash build up requires the booster fans to work harder to push the combustion air out the common stack. Hence, the booster fans were designed to operate through a wide range of inlet pressure variability and as such have a high range of flexibility.

During initial start-up of Unit 1, at the end of the tie-in outage in September 2011, the Unit 1 boiler was clean, Unit 2 was not yet tied into the new scrubber, and the booster fan inlet dampers were properly set. This condition of a very clean Unit 1 and no Unit 2 into the scrubber represented the low end of the full pressure drop range of operation and created challenges for the booster fan operation, specifically the combustion process and draft system. Almost immediately, PSNH recognized that operating in this low end of the pressure range should be reviewed and improved if needed for long term stable operations. A few days after Unit 1 came on line with the Scrubber, discussions were held between PSNH and URS to review operations and verify draft system conditions which concluded in the agreement that some changes were in fact needed. PSNH and URS reviewed solution paths, reviewed improvement options, and promptly proceeded with a solution. These potential solutions were identified quickly as this circumstance was not unanticipated; options to adjust the operation of the new draft system and best operate the unit(s) had been discussed previously. In fact, early in the design phase, costly design and equipment options were not chosen; recognizing that lower cost options were readily available and could be selected to best target actual conditions once the scrubber went into operations. Similarly, PSNH determined that to install the recirculation ducts earlier in 2011 during the Unit 1 tie-in outage was not appropriate because their need was not proven nor would it be known until after at least Unit 1 came on line (and possibly after both units came back from their tie-in outages).

During the PSNH / URS discussion, in addition to the recirculation duct solution, a variety of alternatives were considered including variable speed fan motors, fan rotor and wheel modifications, and creating some type of draft system pressure drop. A decision to move forward with the installation of recirculation ducts was made when it was confirmed that the other solutions were more costly and/or introduced schedule and operational risks. The recirculation duct solution chosen was the lowest cost and most reliable and technologically proven path to follow, and had the least risk of problems. The decision to proceed was made in the second week of October; about two weeks after Unit 1 began operation after its tie-in outage. This included the procurement and installation of 7 feet diameter recirculation duct with dampers. With a design engineered in mid-October and expedited procurement activities, installation plans were developed. This work required both units to be out of service so the expedited effort allowed the work to be completed during the upcoming October/November outages. Based on material arriving on the site as well as coordination with other Unit 1 and Unit 2 work, this equipment was installed during the Unit 2 Scrubber tie-in outage and the shorter Unit 1 outage during the Unit 2 tie in.

For planning and scheduling, best efforts were made to estimate and schedule the steps needed to execute this work since no prior similar job could be referenced for proven logic or task durations. Also, estimated equipment deliveries were used. The work area was restrictive. All work required access by ladders and use of cranes due to the installation locations. As plans for access to ducts were developed to prepare for this work and as work platforms were set, it was clear the logistics of this job would be challenging. The tie-in locations were 60 to 75 feet in the air, away from any existing platforms or access means. Thus an installation challenge was a key element of the work which contributed to schedule challenges and adjustments.

The Unit 1 outage during the Unit 2 tie in outage was taken primarily to tie-in new duct work to the Unit 2 chimney. This outage began on October 31 and ended on November 13. This work on the Unit 1 outlet duct provides for the ability of Unit 1 to operate independent of the Scrubber in certain circumstances. During this planned work, the recirculation duct on Unit 1 was installed so no additional lost availability on Unit 1 was incurred by the recirculation duct installation.

The Unit 2 scrubber tie-in outage provided the opportunity for the recirculation duct to be installed on Unit 2. This tie-in outage had a significant scope of work to which the recirculation duct installation was added. The initial schedule had an outage end date of November 11. The outage schedule did need to be adjusted a number of times (longer and shorter), during the four week outage. The actual end date was November 14, still a week ahead of the ISO-NE scheduled end date of November 21. While the outage did extend 3 days past the initial schedule end date, this change was not specifically due to completing the installation of the Unit 2 recirculation ducts, but rather the outcome of many one-time tasks associated with the tie in of the new scrubber and typical maintenance overhaul schedule changes.

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Re: Staff-02, Q-Staff-015, Please provide an organization chart that shows the administrative and functional reporting relationship between Distribution and Transmission vegetation management.

**Response:**
The administrative link between the transmission rights-of-way maintenance activities and the subsequent vegetation maintenance on the distribution facilities within these shared rights-of-way falls between the Manager - Transmission Vegetation Management for Northeast Utilities and the Supervisor - PSNH Vegetation Management. All other VM activities are solely the responsibility of Transmission VM or Distribution VM and are managed separately. The common point of management oversight for Transmission and Distribution VM is the Executive Vice President & Chief Operating Officer for Northeast Utilities.

Transmission VM is responsible for the management of the transmission assets which includes all rights-of-way that contain transmission facilities. In addition, any distribution facilities located within a transmission right-of-way will have the vegetation within the right-of-way managed at the same time under the same clearing contract as the transmission facilities. The costs for the work associated with the distribution facilities is charged back to distribution. It is a more efficient and less costly way to have these distribution facilities maintained.

The decision on the maintenance schedule and what facilities are maintained in shared rights-of-way is made by Transmission as the transmission facilities are regulated under NERC/FERC so this drives the schedule. Distribution VM is only provided the schedule of which distribution facilities will be managed under the transmission mowing program and the estimated costs are provided to Distribution for budgeting purposes. Normally, the distribution facilities are maintained on a 4 year schedule, however, there are some transmission facilities that are maintained on a 3 year schedule (NERC regulated facilities) and any distribution facilities in these rights-of-way are also managed in that 3 year cycle.

Specifications for rights-of-way vegetation control are the same for both transmission and distribution facilities. However, this maintenance performed by Transmission on the distribution facilities is limited to the brush work within the maintained areas of the right-of-way. Any obvious vegetation hazards beyond the maintained area that could affect the distribution facilities are forwarded to the Distribution VM section for investigation and resolution. Tree and vegetation beyond the maintained limits of the right-of-way on the side of the right-of-way where the distribution lines may be located are maintained by the Distribution VM section.

**Public Service Company of New Hampshire**
**Docket No. DE 12-116**

**Technical Session TS-01**
**Dated: 09/06/2012**
**Q-TECH-008**
**Page 1 of 1**

**Witness:** **William H. Smagula**
**Request from:** **New Hampshire Public Utilities Commission Staff**

**Question:**
Please provide an update of the status of the replacement of the Merrimack CT exciters.

**Response:**
In November 2010, PSNH procured a replacement voltage regulator for Merrimack CT2. The new voltage regulator was an in-kind replacement, but not an exact replacement according to ISO-NE. The in-kind replacement was purchased because the exact replacement device was no longer available. Upon receiving the voltage regulator, PSNH notified and submitted equipment specifications to the ISO-NE Stability Task Force (STF) and Stability Studies Group (SSG) that a new in-kind voltage regulator was going to be installed. PSNH intended to install the voltage regulator during the next planned outage, which was scheduled for April 14, 2011.

The ISO-NE STF and SSG would not approve the installation of the new CT2 voltage regulator because it was not an exact replacement. ISO-NE felt the new voltage regulator was built with different control philosophy and functionality and required a system stability analysis. After several discussions between in-house personnel and ISO-NE, PSNH secured the resources of a qualified engineering firm in January 2012, and submitted an application to ISO-NE which included the scope of the required stability study. Through successful negotiation with ISO-NE, this study also included a new CT1 voltage regulator. In August 2012, ISO-NE STF and SSG approved the scope of the study. The stability analysis will be completed in accordance with the approved scope and submitted for final approval to the ISO-NE Reliability Committee in the fall of 2012. Once the ISO-NE Reliability committee approves the study, PSNH will move forward with the installation of the CT2 voltage regulator, and procure and install a new voltage regulator for CT1.