Public Service
of New Hampshire

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The Northeast Utilities System

Gary A. Long
President and Chief Operating Officer

September 2, 2008

Ms. Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 Fruit Street
Concord, New Hampshire 03301

Re: *Docket No. DE 08-103*
Public Service Company of New Hampshire
Merrimack Station Scrubber Project
Request for Information

Dear Secretary Howland:

Pursuant to the Commission's Secretarial Letter, dated August 22, 2008, Public Service Company of New Hampshire ("PSNH" or the "Company") provides this response to the Request for Information regarding the legislatively mandated installation of wet flue gas desulphurization technology ("scrubber" technology) at Merrimack Station, to be installed as soon as possible but in no case later than July 2013. We have enclosed an original and six copies of PSNH's response.

This filing demonstrates that following the installation of the scrubber, Merrimack Station will continue to be a vital base-load source for reliable and affordable power in the State of New Hampshire, and will have the added benefit of being among the cleanest coal-burning plants in the nation. PSNH is confident that up to the initiation of this inquiry, it was diligently pursuing and complying with the legal mandates contained in 2006 N.H. Laws, Chapter 105, the mercury emissions reduction law ("Scrubber Law"), by moving forward rapidly with the installation of scrubber technology at Merrimack Station.

As required by the Commission's Request for Information, PSNH is providing a memorandum of law, project status report, and response to specific economic inquiries. This information will serve to support the legislature's finding that the installation of the scrubber at Merrimack Station ("the scrubber project" or "Clean Air Project") is "in the public interest of the citizens of New Hampshire and the customers of the affected sources." RSA 125-O:11, VI. The legislature, in reaching its conclusion that the scrubber installation is in the public interest, did not limit itself to economic considerations, but rather performed a careful balancing of the costs and the ensuing benefits to the public health, welfare, economy, and environment (including improved air quality and the protection of natural resources)—benefits which contribute to sustaining the vibrancy of the State and its citizens as a whole. As part of its inquiry, the Commission must review and comply with the General Court's Statement of Purpose and Findings (RSA 125-O:11) as well as the larger statutory context as delineated in the Findings and Purpose of the Multiple Pollutant Reduction Program (RSA 125-O:1)("the Clean Power Act") in which these societal prerogatives are prioritized.

PSNH has a long history of collaboration with state policymakers and the resolution of difficult and challenging environmental issues. We are proud of our consistently proactive environmental stewardship which includes: installation of the first-in-the-nation utility-owned selective catalytic reduction system at Merrimack Station Unit 2 in 1995 and Unit 1 in 1999 to capture NOx emissions; the successful, internationally lauded conversion of a fossil-fuel unit (Schiller Unit 5) in our fleet to a wood-burning facility; our vigorous collaboration on, and crafting of, the first-in-the-nation groundbreaking four-pollutant bill, the Clean Power Act, RSA Chapter 125-O; and now, the aggressive installation of a scrubber system at Merrimack Station to significantly reduce mercury and sulfur dioxide emissions in compliance with the Scrubber Law. At its core, the Scrubber Law is an environmentally motivated law which will result in improvements to air quality. With the Clean Air Project, PSNH will capture, at a minimum, 80% of the mercury entering its coal-fired power boilers which otherwise could be released to the atmosphere. Additionally, the scrubber technology will remove more than 30,000 tons of SO2 emissions each year. These significant environmental benefits were viewed by the legislature as critical goals, in the public interest, to be accomplished on an accelerated basis.

The Scrubber Law is itself another example of PSNH's willingness to work with state policymakers in resolving critical issues. It is the product of a lengthy collaborative effort that PSNH spearheaded along with the Governor's Office, the Office of Energy and Planning, the Department of Environmental Services, and a number of legislators and environmental groups. (See the legislative history included in PSNH's Memorandum of Law.) The legislature, recognizing that the Scrubber Law represented the delicate balancing of numerous interests, found the law in its entirety to be in the public interest, as it has plainly and clearly stated within the law itself, and, in fact, further determined to protect the integrity of the statutory language with a finding emphasizing the non-severability of the law's provisions. (RSA 125-O:11, VIII: "The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of cost, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components.")

The Clean Air Project is a vast and complex engineering and craft labor challenge that is in progress and will take another four years to complete. At its peak, and in addition to the engineering and management support services, the project will require the efforts of more than 300 union craft workers. PSNH has reached a written accord with organized labor leadership to utilize union labor on this project to ensure the availability of critical skilled craft workers and to prioritize work safety on the job. In a recessionary national economy, the importance of this project to craft labor in terms of steady in-state employment cannot be over-emphasized—one more example of an important public interest.

Because of its size and complexity, the Clean Air Project must be an extremely well managed, carefully orchestrated project, and must firmly adhere to critical milestones established in the overarching project schedule which will control the work of numerous contractors and subcontractors. PSNH has already completed a number of critical milestones to ensure project success, as further detailed in this filing.

At this juncture, PSNH has diligently gone through competitive bidding processes for each major "island" of work and has proceeded to negotiate fixed-price contracts with selected vendors. The contracts for the scrubber itself and for the new chimney stand ready to be finalized and executed; the contract for the waste-water treatment facility and site preparation are in final negotiations. Any delay in issuing these contracts will be a major setback for this project and will result in additional costs to our customers. Contractors and their subcontractors are only willing to hold fixed prices for an abbreviated period of time given the rapid escalation of the prices of raw materials and their need to lock in shop time well in advance for the manufacturing of components. If any one of PSNH's major contractors is unwilling to hold prices or contractual terms or to extend the deadline for execution of contracts, the scrubber project schedule has the potential to be irreparably disrupted and harmed. This is because the nature of the scrubber project and the site layout require the sequential completion of many of the construction islands (for example, consider the new chimney: the foundation work must be done in non-winter months, followed by the construction of the chimney "shell" which must be completed in order for the area surrounding the chimney or "drop zone" to be released before other work can proceed for obvious safety reasons). As a result, this means that even a short delay now will have a domino effect and a greater than day-for-day impact on the entire project with the likely result of significant additional costs to the project.

We are mindful of the legislature's mandate that the scrubber project proceed on an accelerated basis and refer the Commission, once again, to the Statement of Purpose and Findings, as well as the legislative history (see PSNH's Memorandum of Law). Any delay in this project will result in added costs, while, conversely, an accelerated schedule will save money. Shaving six months to a year off the project timeline saves significantly on AFUDC costs, avoids escalation in costs of materials and labor, and will result in early compliance credits for PSNH's customers (Economic Performance Incentives, RSA 125-O:16). We respectfully ask the Commission's assistance in complying with the law by expediting the resolution of this inquiry.

It should surprise no one that the costs of this project have increased significantly over the original preliminary estimates made in late 2004-2005. On May 15, 2008, the *Wall Street Journal* reported on the escalation in prices of commodities due to unrelenting global demand--steel prices, just five months into the new year, were already up 40-50% for the year; coking coal and scrap steel, key ingredients in steelmaking, had soared 100%; along with a 71% increase in iron ore prices--all of which are "part of a broader surge in raw-materials prices amid tight supplies and soaring global demand, fueled in part by the rapid industrialization of India, China and other developing nations." However, the cost increases involved in a plant modification are dwarfed by the costs of constructing a new plant which have more than doubled in recent years. According to the Cambridge Energy Research Associates, "the construction of new generating capacity that would have cost $1 billion in 2000 would cost $2.31 billion if construction began today" with most of that increase occurring since 2005. (*Wall Street Journal*, May 27, 2008.) PSNH would like to emphasize: time is money in this market.

Merrimack Station's continued operation ensures that New England has continued fuel diversity and energy security. The New England region is already highly reliant on natural gas, and subject to its high price volatility and the vagaries of the natural gas market, as a fuel source for the power generation sector. Even so, there is very limited activity, and to this point in time, very unsuccessful efforts, to add new base-load power generation to the New England grid. As the economy remains difficult, and credit markets tight, the ability to site, permit, finance, and construct new base-load generation has become nearly impossible. Preservation of the key existing base-load generation resources like Merrimack Station, while maintaining its positive economics for customers, is critical to the region's future. This is particularly true in the case of Merrimack Station which provides not only low-cost energy but has a remarkable record of reliability characterized by record-breaking periods of lengthy continuous operation (in 2004, Merrimack Unit 1 and Merrimack Unit 2 both outperformed previous station operation records—Merrimack Unit 1 ran continuously 122 days and Merrimack Unit 2 ran 147 days). In addition, in 2007, Merrimack Station produced more energy than it ever has in its decades of operation. Clearly, the Station is functioning extremely well, as a direct result of strategic equipment repairs and replacements, well executed maintenance work, well performed operations activities, a dedicated workforce, and a strong and experienced management team.

Beyond the benefits PSNH's operation of Merrimack Station provides to customers in terms of lower electric energy prices and reliability to the New England electric grid, it should be recognized that the operation of Merrimack Station is a significant contributor to the local and state economy—another fact supporting the legislature's public interest finding. Merrimack Station employs approximately 100 highly skilled and dedicated employees in what has become an increasingly limited "manufacturing" sector of our state's economy. In addition, there is significant company support staff for the Station. During annual outages and construction projects, the number of jobs provided increases substantially. PSNH, through its operation of Merrimack Station, contributes annually $758,000 in state utility/property taxes and $2.7 million in local property taxes. This in-state support to the economy reaches beyond wages and tax benefits and extends to the large quantity of materials and supplies and services for which PSNH contracts to operate and maintain the facility on an annual basis.

PSNH has met every environmental challenge head on and met or exceeded expectations in achieving environmental benefits, all of which have been in the public interest. Today, the challenge is mercury—a challenge we are striving to meet. With the installation of a scrubber at Merrimack Station, PSNH will maintain and enhance its standing as the lowest emitting coal-fired power generator in the region. We are excited about this project and the positive impact it will have on our environment. We remain confident that this can be achieved while continuing to provide economic, reliable base-load power for our customers over the period of the scrubber's operation.

PSNH urges the Commission to act expeditiously to resolve this inquiry so that PSNH may resume the commitment of capital and manpower necessary to install the scrubber technology at its Merrimack Station as mandated by law. PSNH stands ready and willing to keep the Commission up to date on the status and progress of the Clean Air Project once we are able to proceed in accordance with the law.

Sincerely,

Gary A Long

Gary A. Long
President and Chief Operating Officer

ORIGINAL
N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-2
Witness William H. Smagula
DO NOT REMOVE FROM FILE

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-02
Dated: 06/18/2012
Q-TC-003
Page 1 of 1

Witness: William H. Smagula
Request from: TransCanada

Question:
Please provide copies of any and all documents that PSNH or any of its employees, officials, representatives, agents or lobbyists provided to DES, any legislator or any state official to support the statement in DES Commissioner Michael Nolin's January 12, 2006 letter to the House Science, Technology & Energy Committee in support of HB 1673 to the effect that the costs of the scrubber will be fully mitigated by the savings in SO2 emission allowances.

Response:
PSNH has never claimed that the cost of the scrubber will be fully mitigated by the savings avoided in the purchase of SO_2 emissions allowances.

Long
EXHIBIT NO. 2
9/16/13
S. ROBIDAS

Witness: William H. Smagula, Terrance J. Large
Request from: TransCanada

Question:
Please provide copies of any and all documents that PSNH or any of its employees, officials, representatives, agents or lobbyists provided to DES, any legislator or any state official to support the statement in DES Commissioner Michael Nolin's January 12, 2006 letter to the House Science, Technology & Energy Committee in support of HB 1673 to the effect that the costs of the scrubber will be fully mitigated by the savings in SO2 emission allowances.

Response:
Please see the attached documents. Also see the response to TC-02, Q-TC-003.

NH Senate Bill 128
Proposed Amendment
Framework
Key Talking Points

October, 2005

Draft
for Discussion Purposes

Proposed Amendment Key Points

- Scrubber Technology to be installed at Merrimack Station, for Unit 1 and Unit 2, to reduce mercury emissions
- Scrubber Technology to be installed no-later-than July 1, 2013
- Required reduction of a minimum of 80% of total mercury input as measured at all PSNH coal fired boilers
- Purchase of Federal mercury credits not allowed for compliance with the mercury portion of RSA 125-O of the NH Clean Power Act
- No alternative or off-site mitigation mechanisms can be used for compliance
- Mercury reductions to occur at coal fired power stations from time bill becomes law, until and prior to Scrubber Technology operational at Merrimack units

Scrubber Technology

- Best known commercially available technology today to remove mercury
- Installation price tag not to exceed $250M
- Scrubber Technology addresses multi-pollutant strategy by reducing other emissions, in particular SO2, achieving an environmentally superior and more cost effective solution
- Coal-fired plant owners required to remove a minimum of 80% of total mercury input as measured at coal fired boilers
- Scrubber project has a long lead time to permit, construct and test before operations; therefore incentives have been created to expedite in-service date insofar as possible
- Incentives have been created to encourage reductions of greater than 80%

Need to establish appropriate baselines

- Data to date is very limited, and varies widely – making it important to determine valid baselines
- Measure coal input mercury over 12 month period following bill passage
- Measure mercury output in a series of quarterly stack tests at Merrimack 1, Merrimack 2 and one unit at Schiller to determine current actual emissions baseline
- 80% reduction requirement measured from input to the boiler to outlet at the stack
- Reductions made prior to Scrubber Technology operation measured from the current actual emissions baseline

Incentives for early reductions

- To ensure reductions in mercury emissions prior to scrubber installation economic incentives exist
- PSNH will strive to achieve mercury reductions from date law becomes effective until Scrubber Technology installed and operating, and to explore new mercury reduction options along the way
- Will identify opportunities to reduce Hg emissions prior to scrubber installation, including Department of Energy trial using carbon injection technology
- Early Reduction Credits will be attained for mercury reductions following passage of the law, and extending until July 1, 2013, thereby incenting Scrubber Technology installation and operation prior to July 1, 2013
- Early Reduction Credit value higher for reductions made sooner
- Early Reduction Credits can be used to balance compliance in high generation or lower scrubber performance years

Incentives to achieve more than 80% mercury removal

- After July 1, 2013, coal fired power plant owner incented to achieve highest mercury removal the technology will allow, with scrubber operation
- Over-Compliance Credits will be attained on a sliding scale, with more credits at higher levels of removal above 80% minimum
- Credits may be converted to other fungible emissions credits (SO2 Allowances) to reduce cost to customers
- After Scrubber Technology operational and performance optimized, coal fired power plant owner is required to sustain mercury removal at those levels into the future

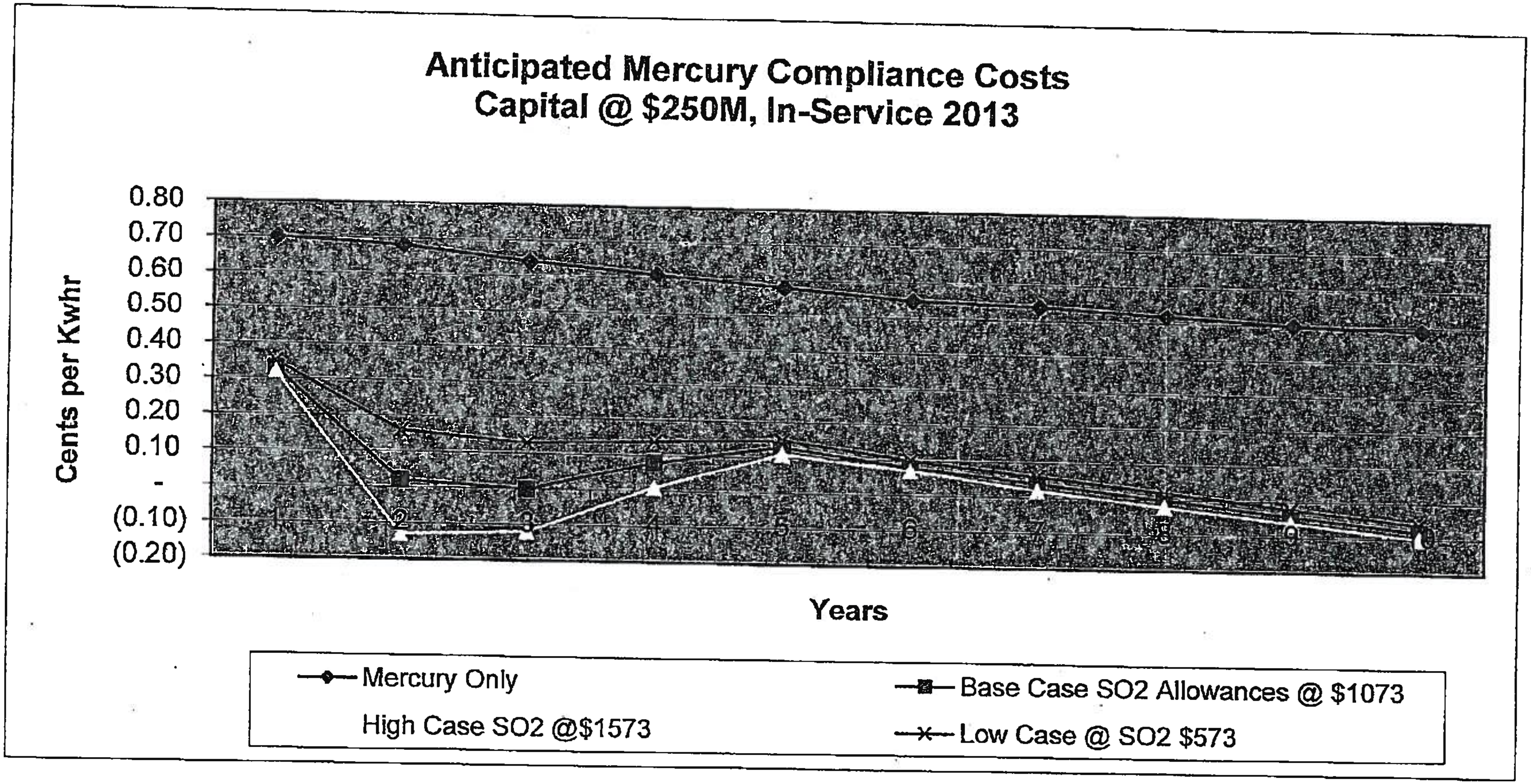
Key Comparisons of NH proposal to current Federal Hg Proposal

- Scrubber Technology and compliance before July 1, 2013
- Target removal of 80% with incentives to achieve much greater removal results
- All On-site reductions
- Federal Mercury Credit purchases not permitted for compliance with Mercury portion of NH RSA 125-O

- Federal Compliance date 2018 - five years later
- Target removal of 70% - ten percent lower
- Cap and Trade system in place, with potential for purchase of mercury Credits for compliance

Costs

- Total project capital costs should not exceed $250M (in year 2013 dollars)
- Amortization of the investment and operational costs will be offset by reductions in SO2 Allowance purchases required by NH Clean Power Act
- Costs in early years following installation are further reduced by incentive provisions of NH Clean Power Act for SO2 reductions


Anticipated Mercury Compliance Costs
Capital @ $250M, In-Service 2013
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
(0.10)
(0.20)
Cents per Kwhr
1
2
3
4
5
6
7
8
9
10
Years
Mercury Only
High Case SO2 @$1573
Base Case SO2 Allowances @ $1073
Low Case @ SO2 $573

Merrimack Station Mercury Collaborative Plan

A New Hampshire Clean Air Leadership Initiative To Reduce Mercury at Merrimack Station in Bow, NH

November 2005

10/05 IAW

The Plan: Collaborative Effort to Reduce NH Mercury Emissions

- Focuses on installing technology at PSNH's Merrimack Station to reduce a minimum of 80% of the mercury in coal no later than 2013
- Provides incentives for PSNH to pursue mercury emissions reduction before 2013
- The emissions control technology will also reduce on-site SO_2 emissions by $90^{+}\%$
- The $250 million cost of the emissions technology would largely be off-set by PSNH not having to purchase SO_2 credits annually
- No trading allowed to meet the minimum 80% removal standard
- Maximizes the environmental benefit for NH residents, while effectively minimizing the financial impact on PSNH customers
- The plan is a result of a collaborative process of NH organizations. It is supported by a diverse coalition

Support for the Plan is Growing

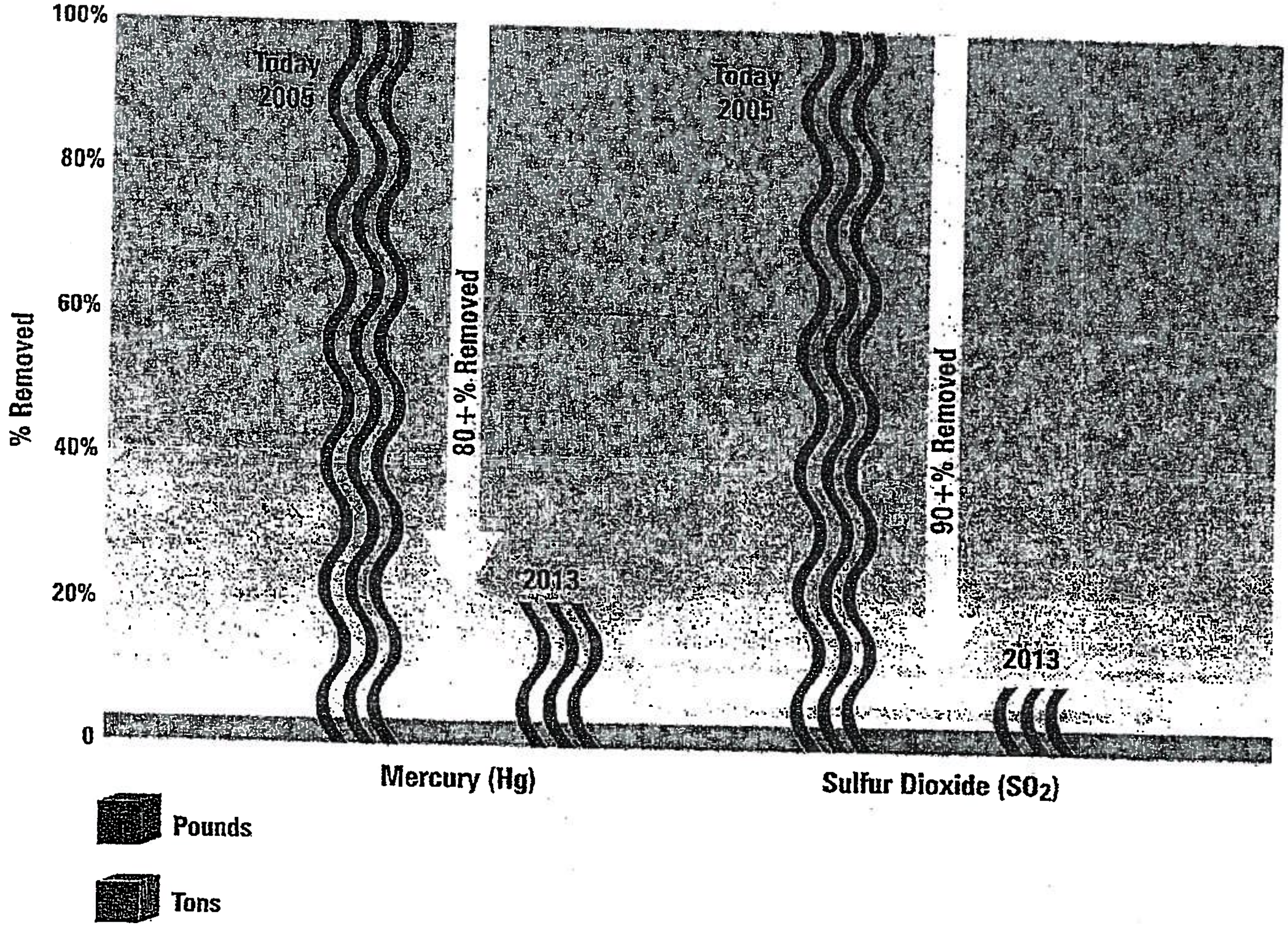
In August 2005, a small group of interested organizations began to discuss creative approaches to reducing mercury emissions. Organizations and NH Legislators that developed the plan include:

- NH Department of Environmental Services
- NH Office of Energy & State Planning
- NH Lakes Association
- NH Audubon Society
- PSNH
- Representative Larry Ross (R-Peterboro)
- Representative Naida Kaen (D-Lee)

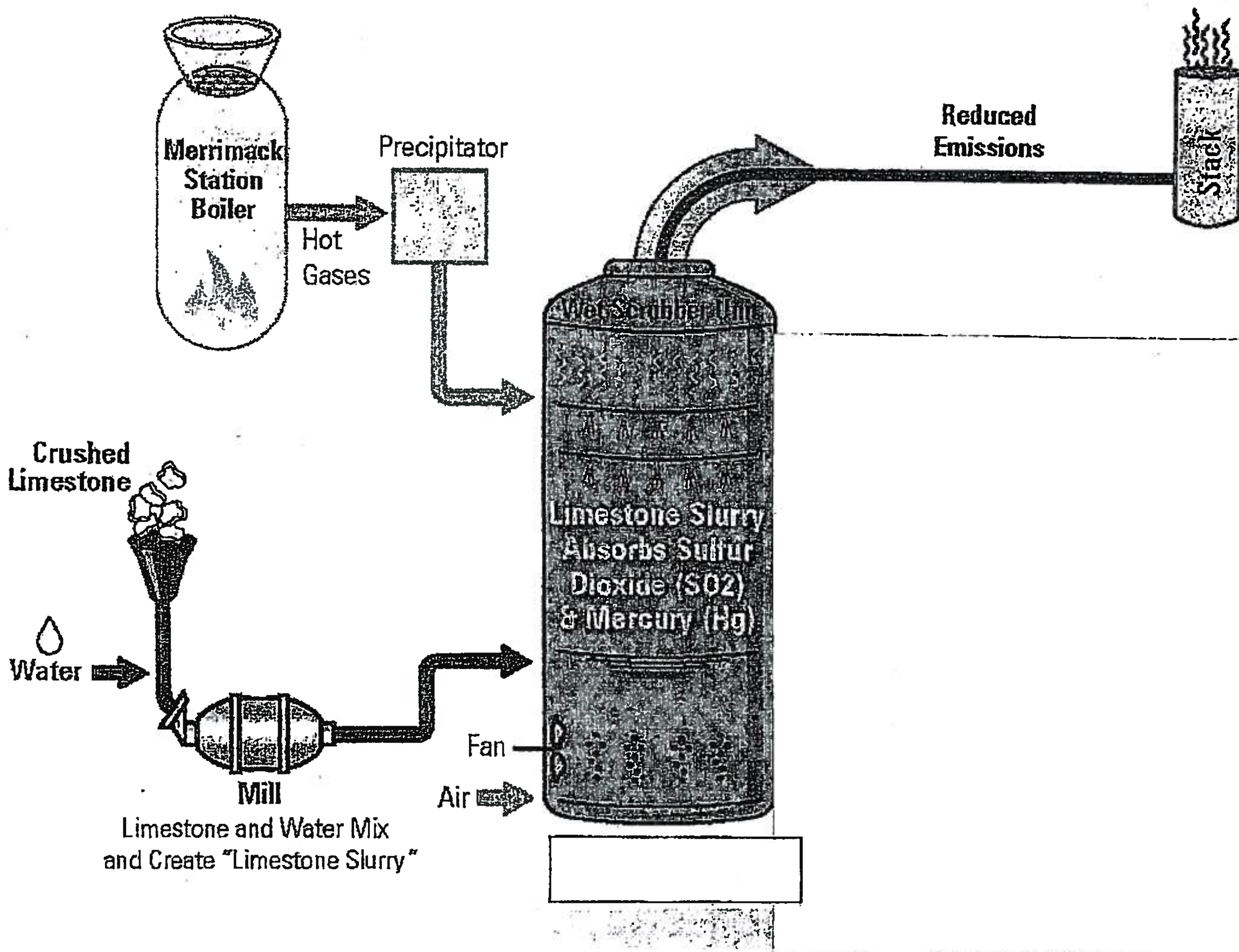
Technology Investment is at the Core of the Plan

- PSNH will install "wet scrubber" technology at Merrimack Station to reduce mercury emissions
- Scrubber technology is commercially available and has a proven track record for reducing SO_2 emissions
- Installation of this technology could cost as much as $250 million
- The cost of this investment would be substantially off-set by reducing the amount of SO_2 credits purchased annually to meet federal and state clean air requirements
- Scrubber technology would be installed and operating no-later-than July 2013

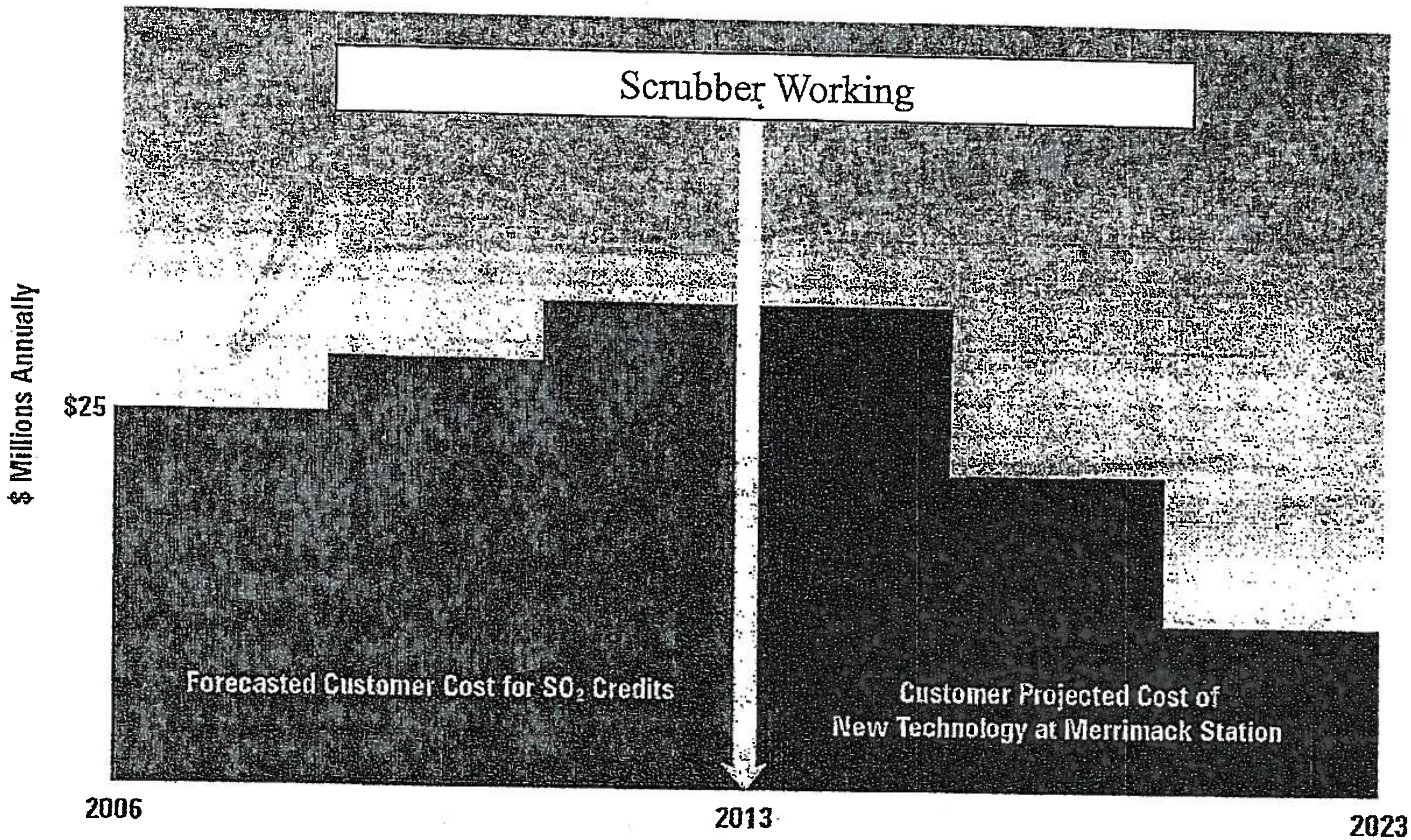
New Technology at Merrimack Station Reduces Emissions



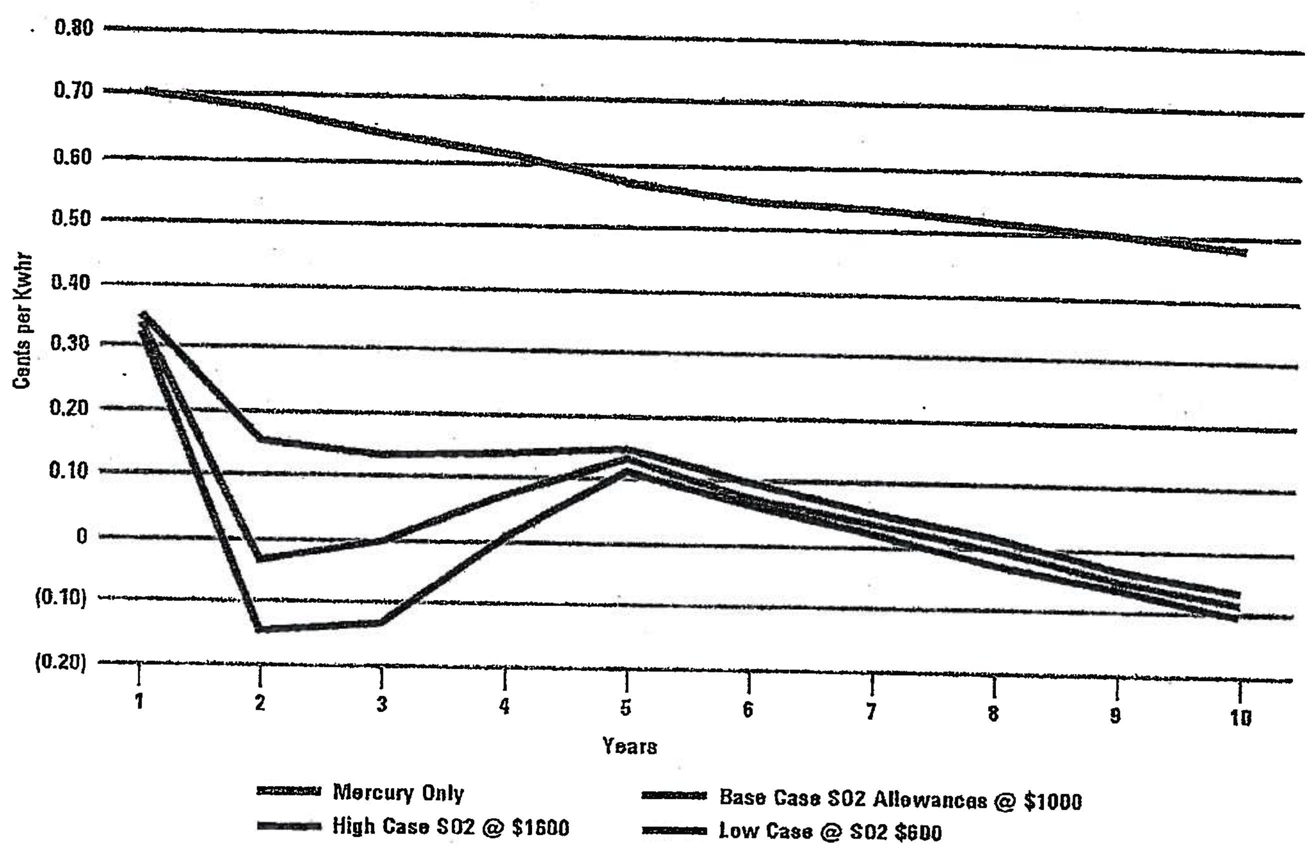
Wet Scrubber Technology for Merrimack Station



The Costs Of The Scrubber Technology Would Be Largely Offset By Reduced Purchase of SO_2 Credits



Credit for SO_2 Reductions Will Significantly Reduce Customer Cost



The Plan Includes Incentives for Maximizing Mercury Reductions After Scrubber Installation

- The plan includes incentives for PSNH to maximize the mercury reduction capabilities of the technology after 2013
- The plan establishes over-compliance credits for mercury removal achievements above 80%
- The plan proposes that these credits be banked for future use or converted to SO_2 credits to offset the cost to customers

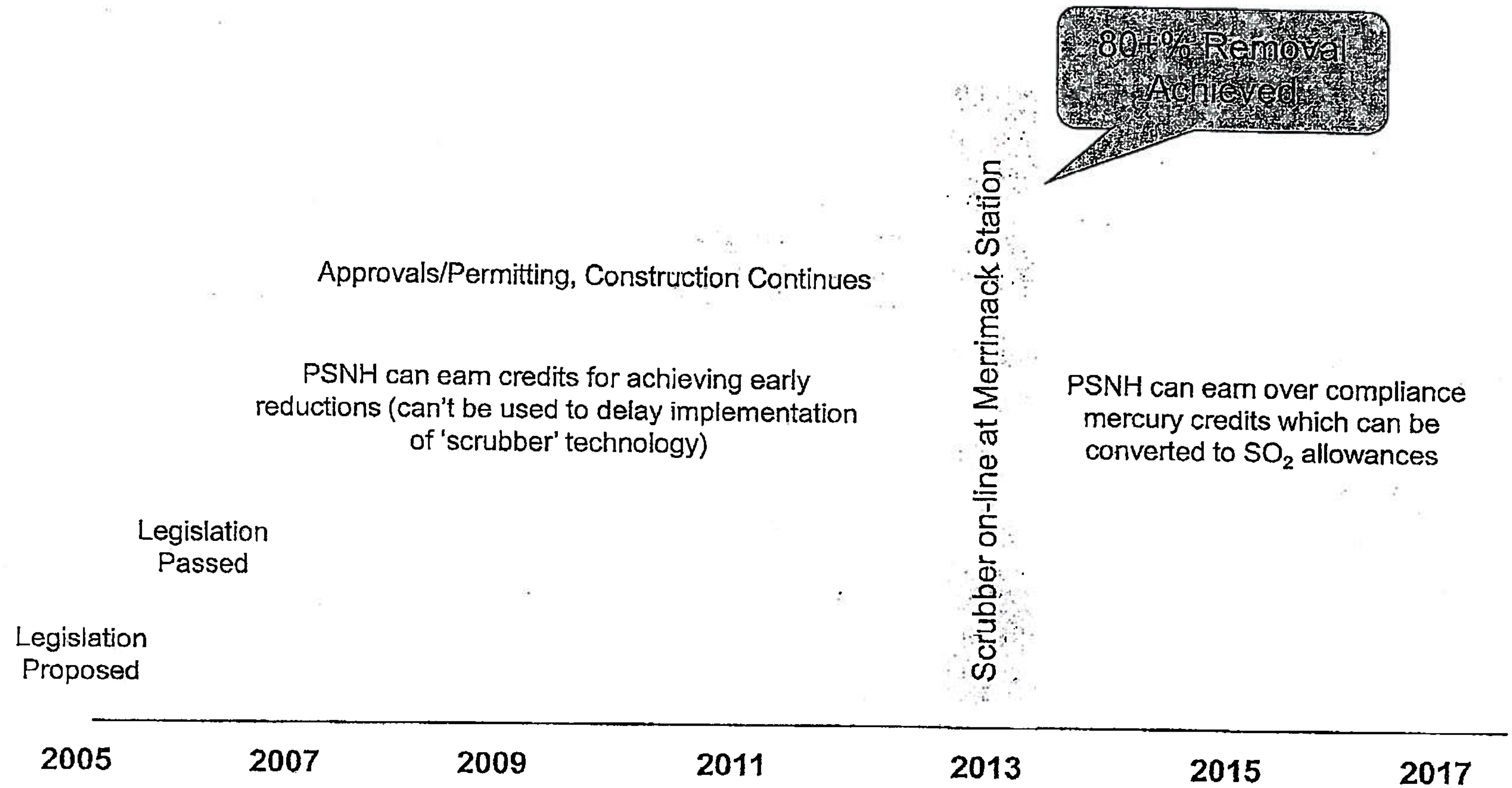
The Plan Offers Incentives for Early Mercury Reductions

- A "credit system" will be established for mercury reductions achieved from when the bill becomes law to July 1, 2013
- Importantly, early emission reduction credits may not be used to delay the scrubber installation
- The earlier mercury reductions are made, the higher the value of the credits
- Prior to scrubber installation, other mercury reduction strategies will be tested and/or implemented to achieve mercury removal while scrubber technology is being designed, permitted and constructed
- Once the scrubber is installed, the early reduction credits can be converted to over-compliance credits where they can be banked or converted to SO_2 allowances

Key Comparisons

Senate Bill 128	❖ Reductions to a total of 24 pounds emitted, achieved by July 2013 with opportunities for off-site reductions
US EPA Guidelines	❖ Target removal of 70%; no incentives for early reductions ❖ Federal compliance date of 2018 ❖ Cap & trade system in place, with potential for purchase of credits for compliance
Collaborative Plan	❖ 80% removal of Mercury by 2013 with incentives for earlier reductions ❖ Incentives for PSNH to maximize reduction capabilities of the technology beyond 2013 ❖ Over-compliance credits established for mercury removal above 80% ❖ All reductions achieved on-site, no purchase of credits permitted for compliance

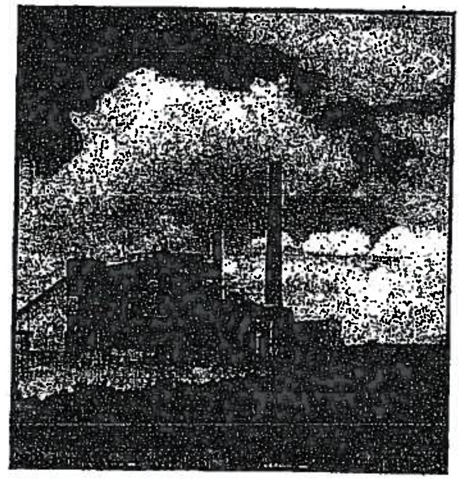
The Plan Framework:
Proposed Mercury Emissions Reduction Timeline



A New Hampshire Clean Air Leadership Initiative at Merrimack Station

Public Service
of New Hampshire

Merrimack Station
Bow, New Hampshire



Fact Sheet

PSNH's Merrimack Station is an important base load plant, operating 24/7 to meet customers' electrical demand in New Hampshire.
Creative environmental initiatives at Merrimack Station have earned the company numerous awards-including the Governor's Award for Pollution Prevention in 1996, and the U.S. environmental Protection Agency's Environmental Merit Award in 1996 and again in 1999.

Facts at a Glance:

- Electric Output: 478 Megawatts of power
- Supplies power to about 190,000 residential, commercial and industrial customers
- Began commercial operation in 1968
- Operates on two primary coal-fired steam turbines(Unit One – 113 MW; Unit Two – 320 MW); also home to two combustion turbines, utilized only during periods of great power demand
- Environmental improvement initiatives – Investment of almost $50 million since 1989

Environmental Initiatives and Improvements:

Although they also have significant operating costs, these improvements have enabled the station to significantly lower its emission of certain pollutants. For example, Merrimack Station now has the lowest NOx (nitrogen oxide) emission rate of any utility coal-fired power plant in all of New England.

1989 Installed an additional electro static precipitator (ESP) on Unit One, resulting in no visible emissions.

1995 Began Unit Two Selective Catalytic Reduction (SCR) system operation, resulting in a 65 percent reduction in NOx emissions. Merrimack Station became the first utility coal-fired plant in the US to install an SCR system.

1995 Installed a Selective Non-Catalytic Reduction (SNCR) system on Merrimack Station Unit One - resulting in a significant reduction in NOx emission.

1998 The early installation of additional catalyst material in the existing Unit Two SCR system, resulted in an 85 percent reduction of NOx emissions. The reduction was of critical importance in a decision by the US EPA not to require automobile tailpipe emission testing in New Hampshire.

1999 Installed an SCR system on the Unit One boiler, resulting in an 85 percent reduction of nitrogen oxides (NOx) emissions - equivalent to the removal of 700,000 automobiles from New Hampshire roads. As a result of this installation, NOx emissions from Merrimack

Station are in compliance with the EPA's NOx standards for new power plants, including gas plants.

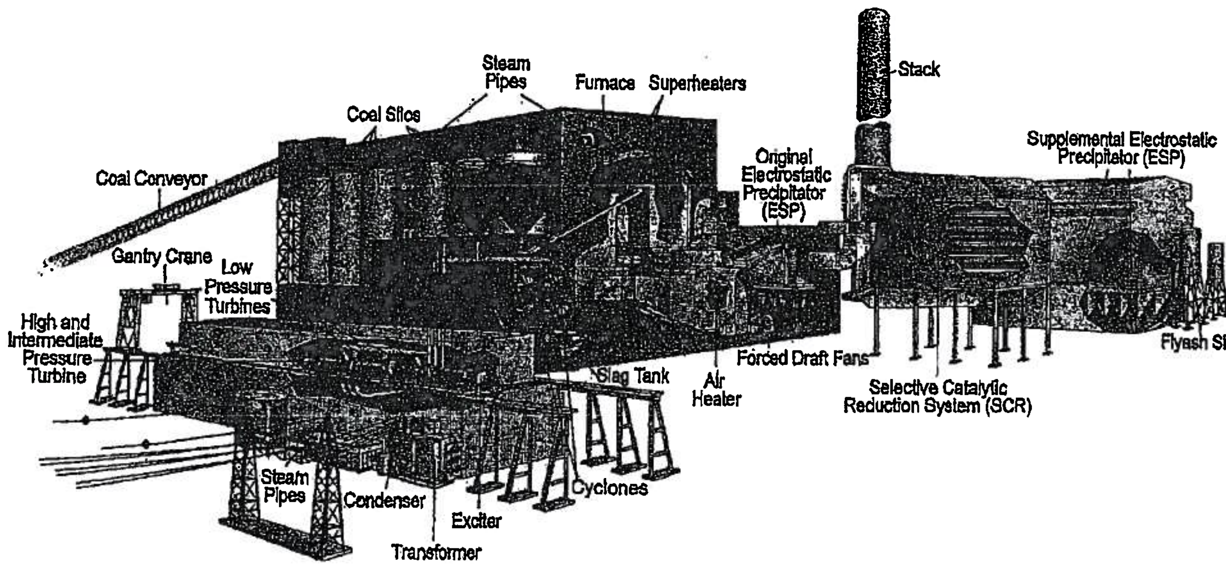
1999 An additional ESP on Unit Two became operational, resulting in reduction of particulate emissions to 0.02 lbs/mmBTU. This is better than the U.S. EPA's particulate and opacity (smoke density) standards for new plants, including gas plants.

2003 Installed upgraded turning vanes for the Unit Two Selective Catalytic Reduction (SCR) system, further reducing NOx emissions.

2002 Upgraded the original ESP on Unit One, resulting in a greater reduction of particulate emissions.

2002 Upgraded the original ESP on Unit Two, resulting in a greater reduction of particulate emissions.

The Inner Workings Of A Power Plant
Making energy at Merrimack Station – Unit Two



Station Environmental Awards

2004 Northeast Utilities 2003 Environmental Leadership Award for significantly reducing the emission of Sulfur Dioxide (SO_2).

1999 US EPA Environmental Merit Award for Unit One NOx emission-reduction that resulted from the installation of a second Selective Catalytic Reduction system at Merrimack Station.

1996 Edison Electric Institute (EEI) Special Distinction Award for collaboration with government agencies and environmental groups to develop an ozone-reduction strategy to meet the Clean Air Act.

1996 US EPA Environmental Merit Award for installation of Unit Two SCR, and for corrosion-reduction system.

1996 New Hampshire Governor's Award for Pollution Prevention for installation of Unit Two SCR.

Public Service of New Hampshire

November 2005

What Is Mercury?

Mercury (Hg) is a naturally occurring element that humans can neither create nor destroy. It enters the environment by normal breakdown of minerals in rocks and soil through exposure to wind and water.

Natural sources of mercury come from volcanoes, oceans, forest fires and other naturally occurring events. Manmade sources include combustion, energy production and incineration.

Mercury is used in medical instruments, electrical equipment and consumer products.

Trace amounts of mercury are found in coal. It accumulates in fish and aquatic species. The greatest exposure to humans is through eating fish, not through inhalation.

What is Sulfur Dioxide?

Sulfur dioxide (SO_2) is produced from the burning of fossil fuels. It is a colorless gas or liquid with a strong odor. It is a common air pollutant that is emitted by coal burning power plants. When the coal is burned, the sulfur dioxide is released into the air. If there is moisture in the air, the sulfur dioxide dissolves into the moisture creating acid rain.

PSNH Mercury Control Initiatives

- Mercury-in-coal analyses (1999, 2002-2003)
- Mercury stack testing at Merrimack and Schiller Stations (2003)
- Technical and economic feasibility study at Merrimack Station (2004)
- Additional Mercury stack testing at Merrimack Station (2004)
- Carbon injection pilot project at Merrimack Station (Summer 2005)
- Application submitted for US Department of Energy Project (Fall 2005)
- Proposed for legislation, 'Wet Scrubber' technology that will reduce Sulfur Dioxide (SO_2) emissions by more than 90 percent and Mercury (Hg) emissions by more than 80 percent (Fall 2005)

Merrimack Station Mercury Collaborative Plan

A New Hampshire Clean Air Leadership
Initiative To Reduce Mercury at
Merrimack Station in Bow, NH

November 2005

Summary Overview

The Plan: Collaborative Effort to Reduce NH Mercury Emissions

- Focuses on installing technology at PSNH's Merrimack Station to reduce a minimum of 80% of the mercury in coal no later than 2013
- Provides incentives for PSNH to pursue mercury emissions reductions before 2013
- The emissions controlled technology would also reduce on-site sulfur dioxide (SO2) emissions by at least 90+%
- The $250 million cost of the emissions technology would largely be off-set by PSNH not having to purchase SO_2 credits annually
- No trading allowed to meet the minimum 80% removal standard
- Maximizes the environmental benefit for NH, while effectively minimizing the financial impact on PSNH customers
- The plan is a result of a collaborative process of NH organizations. It was developed by a diverse coalition, including:
    - NH Department of Environmental Services
    - NH Office of Energy & State Planning
    - NH Lakes Association
    - NH Audubon Society
    - PSNH
    - Representative Larry Ross (R-Peterboro)
    - representative Naida Kaen (D-Lee)

The Plan Offers Incentives for Early Mercury Reductions

- Prior to scrubber installation, other mercury reduction strategies will be pursued to achieve mercury removal while scrubber technology is being designed, permitted and constructed
- A "credit system" will be established for early mercury reductions achieved from when the bill becomes law to July 1, 2013

November 2005

- Importantly, early emission reduction credits may not be used to delay the scrubber installation

- The earlier mercury reductions are made, the higher the value of the credits

- Once the scrubber is installed, the early reduction credits can be converted to over-compliance credits where they can be "banked" or converted to SO2 allowances

The Plan Includes Incentives for Maximizing Mercury Reductions

- The plan includes incentives for PSNH to maximize the mercury reduction capabilities of the technology after 2013

- The plan establishes over-compliance credits for mercury removal achievements above 80%

- The plan proposes that these credits be banked for future use or converted to SO2 credits to offset the cost to customers

Support for the Plan is Growing

The plan is the result of a collaborative process of NH organizations starting early summer 2005. Organizations and NH Legislators supporting the plan include:

- NH Department of Environmental Services
- NH Lakes Association
- NH Audubon Society
- PSNH
- Society for the Protection of NH Forests
- Representative Larry Ross (R-Peterboro)
- Representative Naida Kaen (D-Dover)

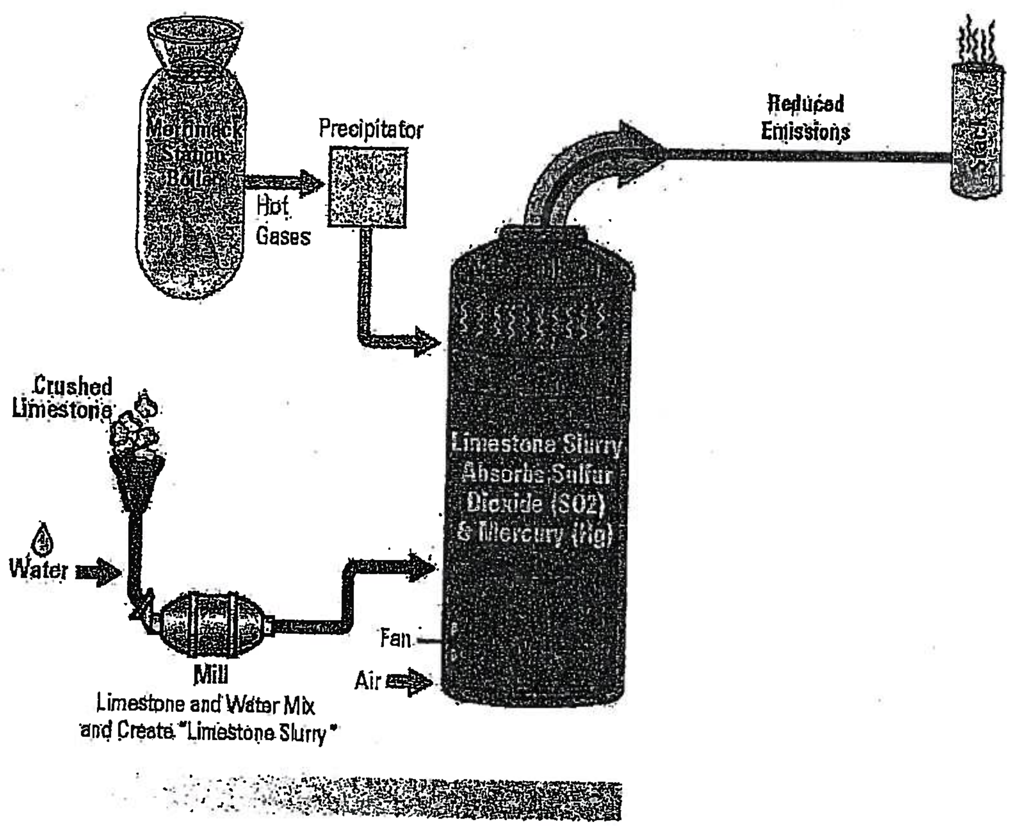
Technology Investment is at the Core of the Plan

- PSNH will install "wet scrubber" technology at Merrimack Station to reduce mercury emissions
- Scrubber technology is commercially available and has a proven track record for reducing SO2 emissions
- Installation of this technology could cost as much as $250 million
- The cost of this investment would be substantially off-set by reducing the amount of SO_2 credits purchased annually by PSNH to meet federal and state clean air requirements
- Scrubber technology would be installed and operating no-later-than July 2013

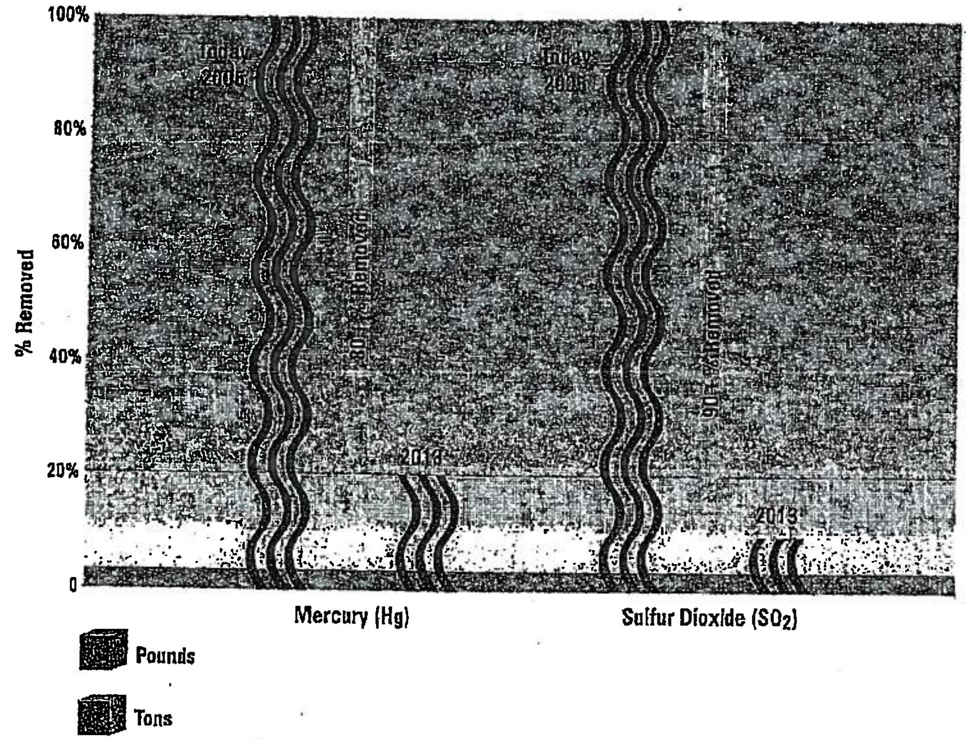
Wet Scrubber Facts

- Wet Scrubber technology is commercially available with a proven track record for reducing sulfur dioxide (SO_2) emissions
- Hot gases from the Merrimack Station boiler will travel through the Precipitator into the Wet Scrubber Unit
- Crushed limestone and water are milled to create a 'slurry' that absorbs SO_2 & Mercury (Hg) within the Wet Scrubber unit reducing emissions going to the stack
- Wet Scrubber technology removes over 90 percent of the SO_2 and over 80 percent of the Hg

Wet Scrubber Technology for Merrimack Station



New Technology For Merrimack Station Dramatically Reduces Emissions



Key Comparisons

Senate Bill 128 (Introduced in January 2005)	• Sets compliance date of 2013 • Reductions to a total of 24 pounds emitted, achieved by July 2013 with opportunities for off-site reductions
US EPA Mercury Guidelines (Introduced in March 2005)	• Sets compliance date of 2018 • Target removal of 70%; no incentives for further reductions • Proposes national cap & trade system for mercury by 2013, with potential for purchase of credits for compliance
Mercury Collaborative Plan (Introduced in November 2005)	• Sets compliance date of 2013 • Requires PSNH to an 80% reduction of Mercury emissions with incentives for earlier reductions • Incentives for PSNH to maximize reduction capabilities of the SO_2 reduction technology beyond 2013 • Over-compliance credits established for Mercury reduction above 80% • All reductions achieved on-site; no purchase of credits permitted for compliance

Reducing Mercury Emissions – Let's Do It Right
By Gary A. Long

The New Hampshire Legislature is considering a mercury reduction initiative that could increase electric rates substantially for PSNH customers. As written, NH Senate Bill-128 could add hundreds of millions of dollars to our energy production costs, and greatly diminish the fuel diversity and economical energy provided by our Merrimack Station in Bow.

The good news is that we believe that there *are* ways to achieve significant reductions in mercury emissions at our coal plants while minimizing rate impacts on our customers, maintaining a diversified fuel mix, and positioning New Hampshire to have future energy costs lower than other New England states.

We would do this by using the same collaborative approach we used to develop broad support for the passage in 2002 of the celebrated New Hampshire Clean Power Act, and previous successful efforts to achieve significant emissions reductions.

Unfortunately, SB-128 is not the result of collaboration, but instead embraces a deeply flawed approach to reducing mercury, and would set in law targets and timelines that are unachievable.

Mercury is a naturally occurring compound that is released globally by volcanic eruptions and by everyday activity that involves combustion of fuels. It is estimated that 60 percent of the mercury deposition in the U.S. comes from overseas – carried by wind patterns from industrial complexes as far away as China. Like many other emissions, mercury is also deposited in New Hampshire from industrial sources in the Ohio River Valley and other areas.

The State of New Hampshire estimates that about 650 pounds of mercury are emitted annually in the state from multiple sources. PSNH's two coal-fired plants emit about 130 pounds annually, about 19 percent of the state's total annual emissions. SB-128 focuses on PSNH power plants for reductions; other sources, which collectively emit more than 80 percent of the state's annual mercury emissions, are not addressed.

In 2002, PSNH, the State of New Hampshire, environmental groups and others made a commitment to reduce mercury emissions as part of the New Hampshire Clean Power Act. All parties agreed to let the U.S. Environmental Protection Agency (EPA) take the lead in setting reduction targets, given that there were *no* federal standards yet regulating mercury emissions at power plants. The Clean Power Act also states that trading programs should be an integral part of any NH initiative to reduce mercury emissions.

Trading involves setting up a marketplace for buying and selling mercury credits – recognizing that mercury deposition in NH also comes from out-of-state sources. Trading programs have been successfully used to significantly and *economically* reduce other emissions, including those causing smog.

In March, the EPA issued new mercury regulations for US coal plants. The rule would require PSNH to reduce its annual mercury emissions by more than 60 percent by 2018 – from 130 pounds to 50 pounds. The EPA also proposes to establish a national "cap and trade" system on mercury emissions to help achieve the reduction targets cost-effectively.

As written, SB-128 is much more aggressive. It requires PSNH to reduce its annual mercury emissions to 50 pounds by 2009, and then to 24 pounds by 2013. Also, SB-128 does *not* allow participation in any trading programs, nor does it encourage the company's participation in alternative mercury mitigation initiatives such as recycling household items containing mercury.

Without alternative mitigation and trading, the only option left to the company to meet the bill's reduction targets is experimental technology.

The fact is that there is *no* commercially available technology for coal-fired power plants which has been proven to achieve the mercury reductions required by SB-128. There are technologies available to reduce mercury emissions from coal-fired power plants', however; real questions exist as to whether any of these technologies alone can achieve the reductions called for in SB-128.

PSNH will implement a pilot program this summer at Merrimack Station to test the effectiveness of one mercury reduction technique, using carbon injection.

PSNH is willing to do its part to reduce mercury, provided it is a realistic plan and considers the impact on our customers' rates. I am hopeful that the Legislature will have the wisdom to reach for policies that balance the needs of its citizens, while positioning the state for a prosperous future.

Gary A. Long is president and chief operating officer of Public Service of New Hampshire.

FAQs

Who was involved in developing the plan?

The proposal to use a wet scrubber system was developed during the summer of 2005 by a small group of interested parties which worked collaboratively to find a mercury reduction method which would achieve the desired goal while minimizing the economic impact on customers. The group included: the NH Office of Energy and Planning; the NH Department of Environmental Services; members of the Legislature; the New Hampshire Audubon Society; the New Hampshire Lakes Association; and PSNH.

How does a wet-scrubber system work?

A wet scrubber system utilizes crushed limestone and water to create a "slurry" which interacts with and absorbs sulfur dioxide and mercury within the flue gas system, prior to the emission stage.

How do you know a wet-scrubber system will work at Merrimack Station?

Wet scrubber technology has been utilized for years as a primary method to reduce the emission of sulfur dioxide (SO2) emissions. In addition, the technology has more recently proven to successfully reduce mercury (Hg) emissions. The history of this technology indicates that it will successfully reduce sulfur and mercury emissions at Merrimack Station?

Why hasn't a wet scrubber system been installed earlier at Merrimack Station?

Merrimack Station has successfully complied with all state and federal environmental regulations to date through a variety of investments and projects. Emission reduction regulations are becoming more stringent and challenging, in turn impacting the evolution of emission reduction technologies and the costs associated with utilizing those technologies or, if available, the purchase of compliance credits. It makes sense from both environmental and business perspectives to now develop a wet scrubber system at Merrimack Station

Why was an 80 percent reduction of mercury selected as a target – can more mercury reduction be achieved?

Yes, more mercury reduction can be achieved. The proposal suggests and anticipates incentives for both interim reduction of mercury emissions, prior to the 2013 startup of a wet scrubber system – and additional mercury emission reduction following the startup. The mercury removal target of 80 percent is in line with the overall goal which was developed by the Legislature as part of its initial proposal, Senate Bill 128.

Why was 2013 selected as the 'start up' of the new technology? Can anything be done in the meantime to reduce mercury emissions?

The original legislative proposal, SB128, set July, 2013 as a target date to achieve a significant reduction of mercury at Merrimack Station. The date makes sense for the wet scrubber proposal, given that it will require significant time for design, permitting, site work and construction. In the meantime, the proposal outlines incentives to encourage interim reductions of mercury through other means, including carbon injection technology.

What will be the cost of the project be?

It is estimated that the project will require a capital investment of up to $250 million and annual operating expenses of about $10 million. As a regulated utility, PSNH must receive authorization from the NH Public Utilities Commission before making any such investment.

How will the project costs be paid?

If the New Hampshire Public Utilities Commission (NHPUC) approves the project, the costs will be recovered from customers through PSNH rates. Importantly, many of these costs will be offset by a reduction in the number of related emission reduction credits which must now be purchased by PSNH. Currently, PSNH spends about $20 million per year on sulfur dioxide credits, and the price of those credits is expected to increase. The proposal anticipates a significant reduction in the required purchase of SO2 credits, thereby offsetting project costs.

Will there be additional employees hired as a result of the project?

Yes. The new system will require some additional fulltime employees to be added to Merrimack Station's current workforce of 100 employees.

ORIGINAL
N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-3
Witness William H. Smagula
DO NOT REMOVE FROM FILE

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-04
Dated: 08/31/2012
Q-TC-009

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

Question:
Please provide a copy of the "Merrimack Station Clean Air Project Strategic Sourcing Plan" dated June 15, 2007.

Response:
Attached is the requested Merrimack Clean Air Project Strategic Sourcing Plan dated June 15, 2007.

**A redacted version is attached. The document contains protected Information, pursuant to the Commission's Order No. 25, 332 dated February 6, 2012 in this docket. Copies of the unreddacted attachment are being provided to the Staff and Office of Consumer Advocate.

Long
EXHIBIT NO. 3
8/16/13
S. ROBIDAS

Public Service of
New Hampshire

Merrimack Station
Clean Air Project

Strategic Sourcing Plan

June 15, 2007

Public Service of
New Hampshire

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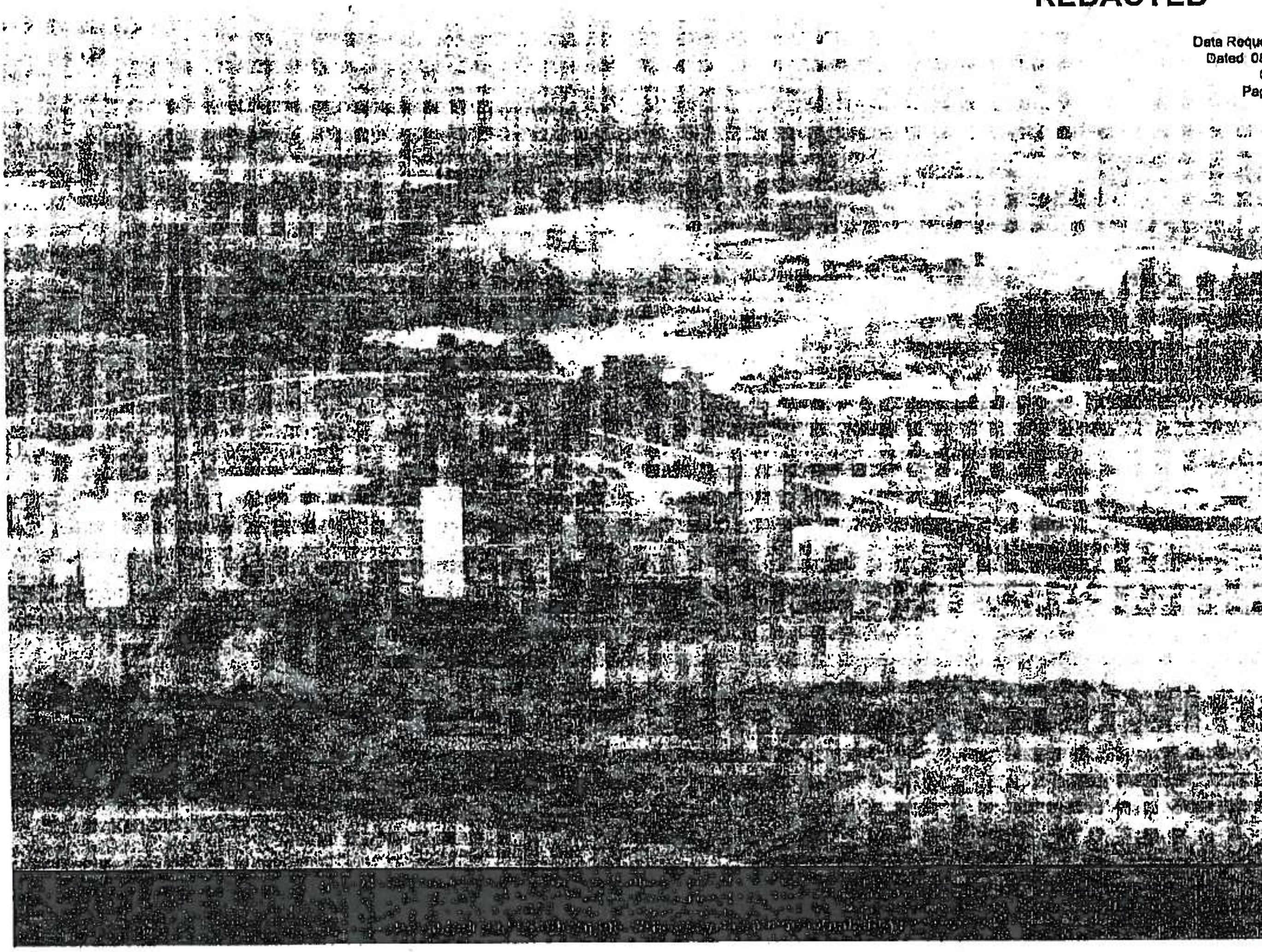


REDACTED

Public Service of
New Hampshire

Executive Summary

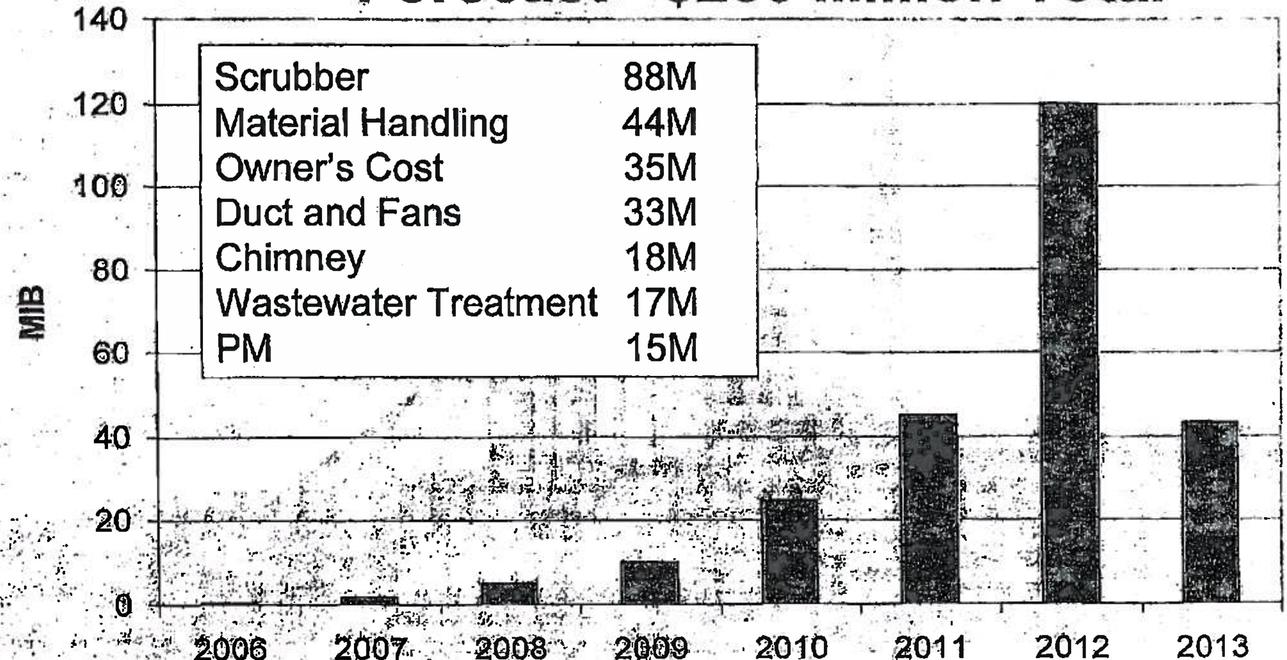
- HB-1673 enacted during 2006 session requires 80% reduction of the mercury emissions from PSNH's coal generating fleet by July 1, 2013
- Merrimack will collect approximately 83% of its mercury emissions, thus mitigating the need for mercury reductions at Schiller Station
- RaCC approval has been provided
- ERMC approved Procurement Strategy
- Program Manager (PM) will be hired (similar to MN in contract format)
- Island contracts are currently expected to be of EPC format. Final contract format will be determined after PM is hired
- Current total project estimate: $250M, to be adjusted upward to reflect recent market activity

[redacted]

REDACTED

Public Service of
New Hampshire

Estimated Project Cost and Cash Forecast - $250 Million Total*



*2006 dollars from Sargent and Lundy in early 2006, to be increased to reflect recent market activity

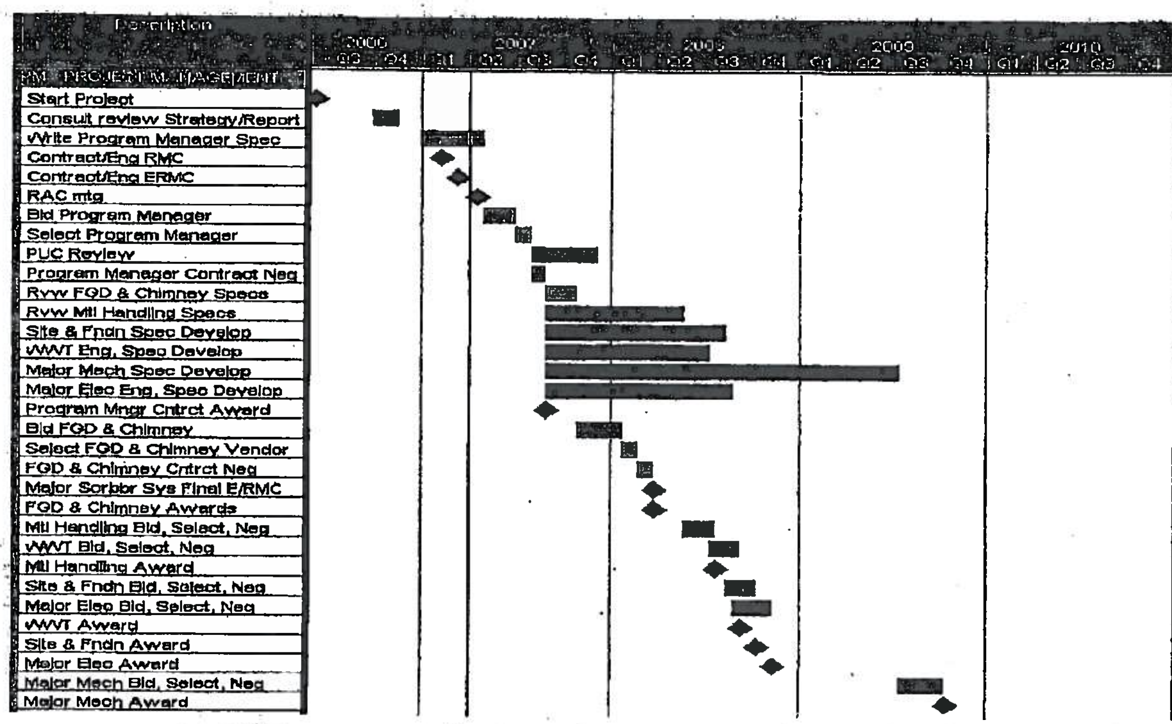
[redacted]

Public Service of New Hampshire

REDACTED

6
Data Request TC-04
Dated: 08/31/2012
Q-TC-009

Procurement Schedule



[redacted]

Public Service of New Hampshire

Evaluation Criteria*

Program Manager
- Commercial 35%
- Technical 40%
- Project Management 25%

Flue Gas Desulphurization (FGD) EPC
- Commercial 45%
- Technical 45%
- Project Management 10%

* Refer to Evaluation Criteria Tables in Frictionless under Evaluation Folder

Public Service of
New Hampshire

Program Manager Summary

- Bid List
  - [redacted], Washington Group
- Scope of Work
  - Project Management, Specifications, Procurement Services, Integration, Construction Management
- Pricing Format
  - Time & Materials with Target Price and "At Risk Provisions"
- Risk Allocation
  - Schedule, Interfaces, Budget, Engineering, Safety
- Performance
  - MK1/MK2 Reliability, Emissions Reduction, Interfaces
- Schedule
  - Milestones, July 1, 2013
- Cost
  - Total Project Cost, PM Cost
- Safety
  - Schedule, Interfaces, Budget, Engineering, Safety

[redacted]

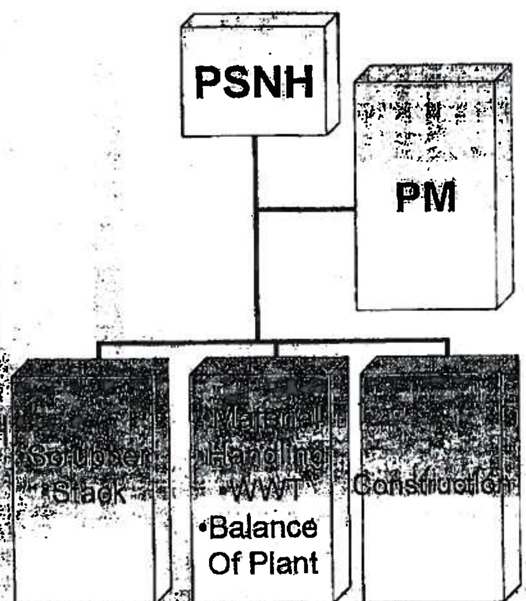
REDACTED

Data Request TC-04
Dated: 08/31/2012
Q-TC-009
Page 10 of 22

Public Service of New Hampshire

Program Manager Contract Overview

- Traditional Program Manager contract format: Engineering, Procurement, and Construction Management Services
- Multiple Fixed Price Supply and Erect and/or Design and Supply Contracts for Major Equipment on NU paper– With Schedule and Performance LD's
- Overall Cost, Schedule, and Integration Risk Remain With PSNH
- Highest Level of Client Involvement, Flexibility and Control
- Phased Commitments Throughout the Project Schedule
- Cash Flow Management



Public Service of
New Hampshire

Scrubber Island
Summary

- EPC Contract Format*
- Bidder List
  - [redacted]
- Scope of Work
  - Reagent Preparation, Absorber, De-watering, Mercury, SO_3 and SO_2 Reduction Guarantees
- Pricing Format
  - Firm Price to Greatest % Possible
- Expected Award – 2nd Quarter of 2008
- Risk Allocation
  - Mercury, SO_3, SO_2 Reduction Guarantee, Critical Path for Schedule, Interfaces with other Islands

* Subject to change pending recommendation of PM and approval from ERMC

[redacted]

REDACTED

Public Service of New Hampshire

Stack Island

Summary

- EPC Contract Format*
- Bidder List
  - [redacted] Hamon Custodis, [redacted]
- Scope of Work
  - Design, Engineering, Material Procurement and erection of wet stack
- Pricing Format
  - Firm Price to Greatest % Possible
- Expected Award – 2nd Quarter of 2008
- Risk Allocation
  - Critical Path for Schedule, Interfaces with other Islands

* Subject to change pending recommendation of PM and approval from ERMC

[redacted]

Public Service of
New Hampshire

Material Handling Island Summary

- EPC Contract Format*
- Bidder List
  - Dearborn Mid-West [redacted]
- Scope of Work
  - Design, Engineering, Material Procurement and erection of the material handling equipment
- Pricing Format
  - Firm Price to Greatest % Possible.
- Expected Award – 3rd Quarter of 2008
- Risk Allocation
  - Critical Path for Schedule, Interfaces with other Islands

* Subject to change pending recommendation of PM and approval from ERMC

[redacted]

Public Service of
New Hampshire

Industry Trends
Long Lead Times Due to High Market Activity

- ❑ Engineer/Constructors - Scrubber Projects and New Coal Projects Compete for "Top" Talent
- ❑ OEMs – Stretched to the Limit, Quality Concerns
- ❑ Critical Material Shortages and Escalating Costs – Steels, Alloys, Copper, Aluminum, Zinc
- ❑ Long Lead Times for Major Equipment – Selling Slots for scrubber components and FD Fans (these will be bid out as soon as possible)
- ❑ Shop Fabrication Space Shortages – Selling Slots
- ❑ Construction Labor – High Demand for Skilled Craft combined with Aging Workforce

[redacted]

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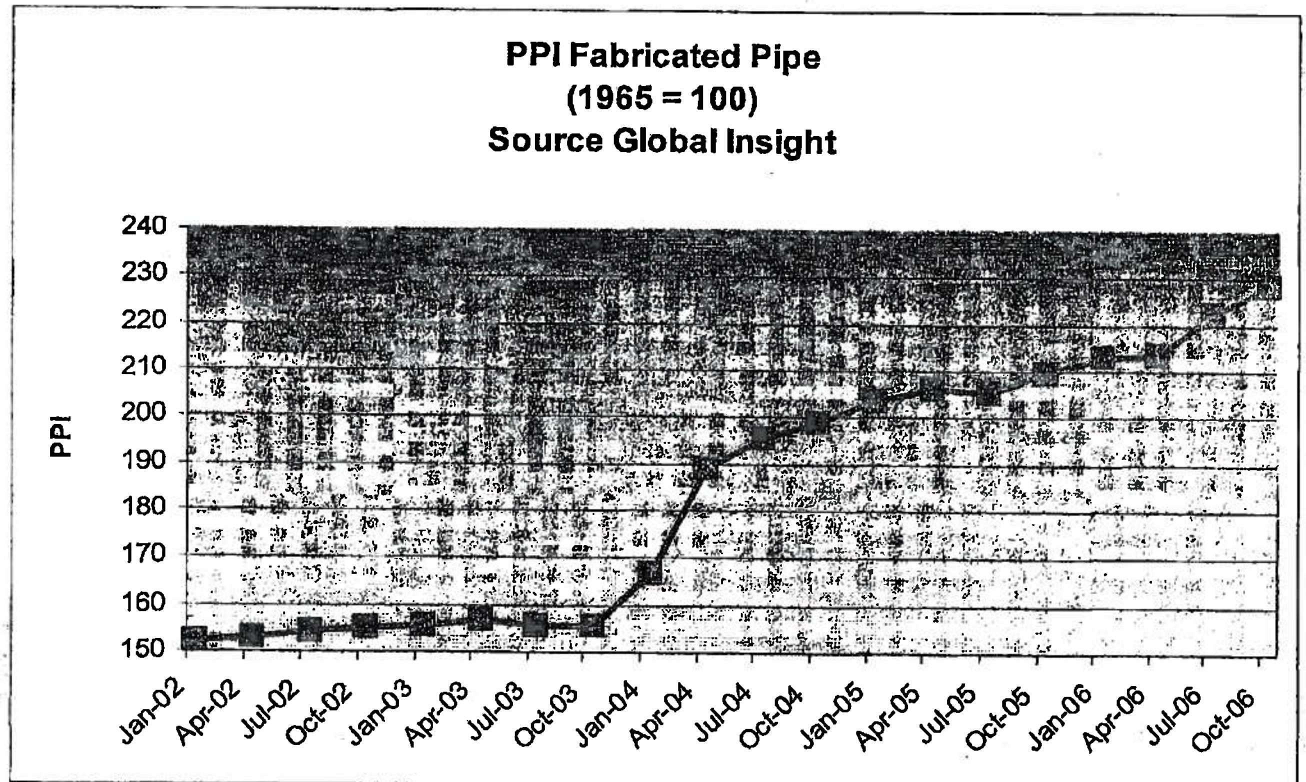
14
Data Request TC-04
Dated: 08/31/2012
Q-TC-009

Public Service of New Hampshire

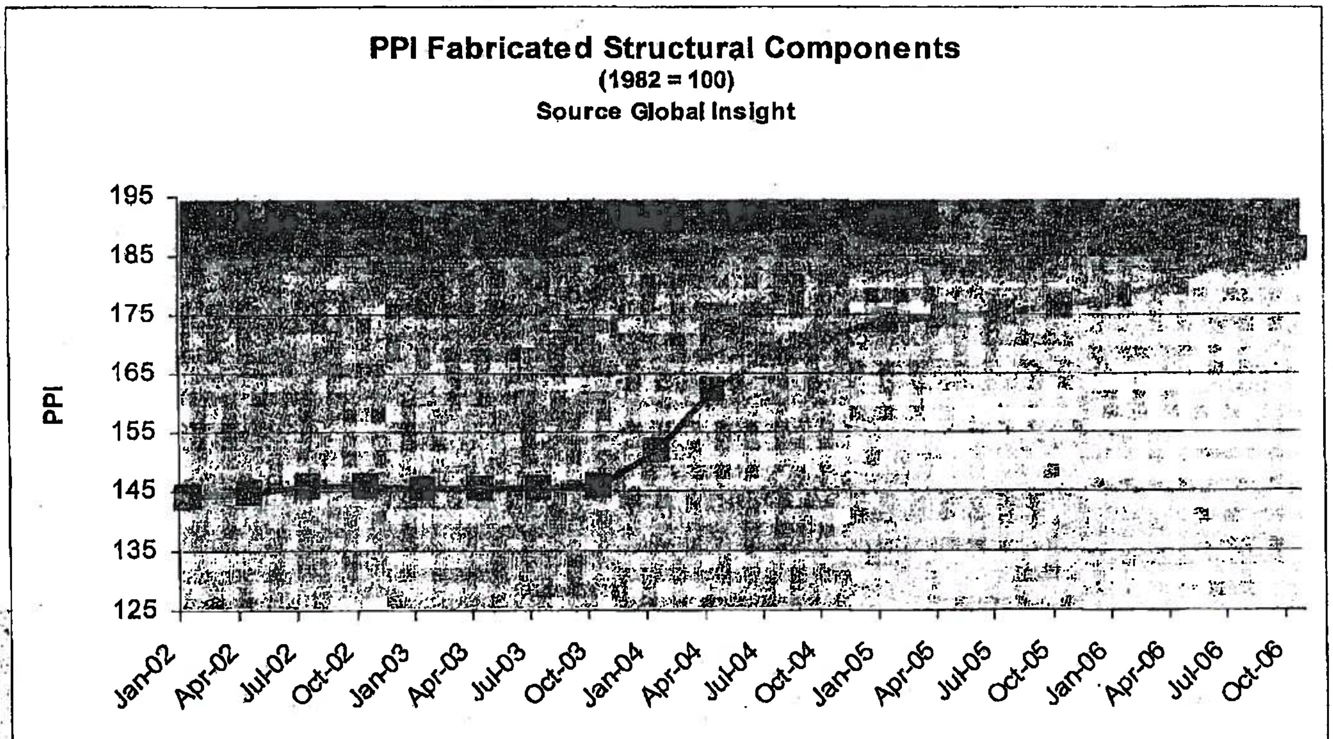
Escalating Materials Costs



[redacted]

Public Service of New Hampshire

Escalating Materials Costs



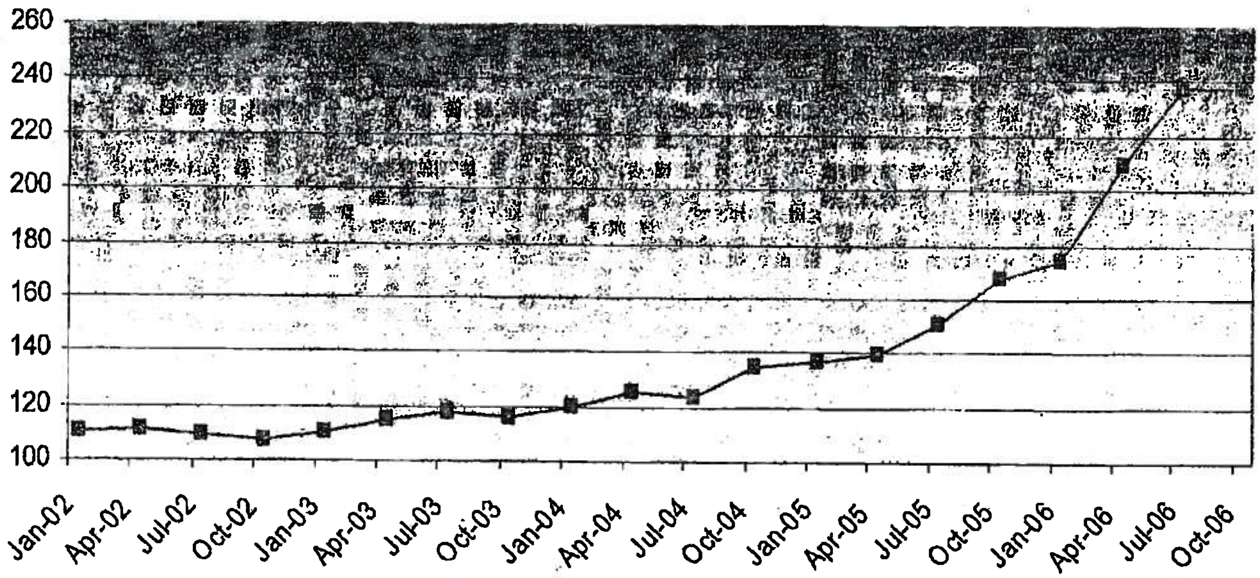
[redacted]

REDACTED

Public Service of New Hampshire

Escalating Materials Costs

PPI Power Wire and Cable
(1970 = 100)
Source: Global Insight



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Public Service of
New Hampshire

Contract Risks & Mitigation - PM

Risk Factor	Ranking	Implications	Mitigation	Ranking After Mitigation
MK1/MK2 Reliability into common Scrubber.	High	Loss of Generation	Negotiate "At Risk Provisions" Performance Guarantees	Medium
Schedule interface/delay of one EPC affects schedule of another EPC	High	Delay claims by affected EPC and PM	Schedule LDs with all EPCs; PM to coordinate EPC contracts; each EPC maintains updated coordination schedules.	Medium
Project Delays	High	Delay in Start up	Use "At Risk Provisions" tied to meeting schedule & early completion bonuses; structure series of "provisions" earned by completion of milestones.	Medium
Division of work interface issues with multiple EPC Contractors.	High	Owner bears contractual risk with contractors for delays caused by other Contractors	Negotiate "At Risk Provisions" in PM contract based on interface issues.	High/Medium
Project Cost Overruns	High	Total project costs in excess of budget	Establish Total Project Target Price, "At Risk Provisions" for meeting targets; detailed subcontract penalties	Medium

[redacted]

Public Service of New Hampshire

Contract Risks & Mitigation – Scrubber Island

Risk Factor	Ranking	Implications	Mitigation	Ranking After Mitigation
Currency & Metals	Medium	Places Project Over Budget	Advanced planning of long lead equipment; ask bidders to bid fixed price, open book or consider hedging as option; use price adjustment clause with stated amounts of commodity and selected, published indices for metals	Medium
Delay of other contractors	Medium	Delay claims by affected EPC and EPOM	Schedule LDs on all EPC contracts; PM efforts to coordinate EPC contracts; each EPC maintains updated coordination schedule; project coordination is topic of each weekly project meeting	Low

[redacted]

REDACTED

Public Service of New Hampshire

Project Team

Name	Role/Title	Responsibility
William Smagula	Project Director	Overall Cost, Schedule, Management, Regulatory, Permits
Michael Hitchko	Project Manager	Cost, Schedule, Sitework and Permit Support
Harold Keyes	Station Manager	Project integration with plant operations
Richard Roy	Project Engineer	Project Cost, Schedule, Technical Compliance, QA/QC, co-chair E/RMC Meetings
Rick Osak / Mary Emerson	Procurement Lead	Procurement Process: Contracting Strategies, Bidder Pre-qualification, Issue RFP, Administer Bidding and Evaluation Processes, Contract Negotiations, co-chair E/RMC Meetings
Linda Landis Jeff Cochran	Legal Dept	Assessment of Risk Allocation, development of Draft Contract Documents, assist in contract negotiations
Dick Gendreau	RW Beck – Procurement Strategy Consultant	Contract Strategy Assistance, Specification development for PM and bid/contract support, as requested by Owner.

[redacted]

Public Service of New Hampshire

Project Support

Name	Role/Title	Responsibility
Sean Adams	Treasury	Credit Review of Potential Contractors, Analysis of EVG, Performance Assurance
Lynn Tillotson	Environmental	Identify environmental compliance requirements for RFP
Lynn Tillotson	Regulatory	Ensure that decisions are consistent with regulatory decisions, approval strategies, and policy Mitigate risk for NU/PSNH and ratepayers
Bob Bersak - Lead	Legal - PSNH	Oversee Legal Strategy
Dave Orpik	Insurance	Ensure that the proper insurance and indemnity requirements are in RFP

[redacted]

Public Service of New Hampshire

Summary

- RFP for PM is currently out for competitive bid.
- RFP for Island contracts will be developed by PM with release planned for Fall of 2007
- Project Completion is required by July 1, 2013.

ORIGINAL

N.H.P.U.C. Case No. DE 11-250

Exhibit No. 27-4

Witness William H. Smagula

DO NOT REMOVE FROM FILE

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference page 16 of the Independent Engineer's Initial Project Review Report contained in attachment WHS-2, in March of 2008 URS reviewed the BOP Cost Estimate with PSNH management and Power Advocate Consultants and in May URS submitted the revised Project cost estimate to PSNH. Please provide a copy of that revised Project cost estimate.

Response:
Attached is the requested May 2008 Project Cost Estimate.

Dorg
EXHIBIT NO. 4
9/16/13
S. ROBIDAS

URS Washington Division

Merrimack FGD Project

5-06-08

Code	Description	Quantity	Manhours	Labor	Perm Materials	Equipment	Supplies	Subcont	Engr'd Equip	Total
Subtota	12-6-501 - C-1 Site Prep/Undergrd Demo/Relo		38,505	1,404,918	1,277,689	132,067	1,958,109	3,947,639	0	8,720,421
Subtota	12-6-503 - C-3 Final Site Finishing & Paving		13,700	457,126	384,427	27,071	146,291	973,494	0	1,988,408
Subtota	12-6-504 - Railroad Work		5,370	0	0	0	0	655,000	0	655,000
Subtota	13-6-101 - Guardhouse		250	0	0	0	0	50000	0	50000
Subtota	13-6-501 - F-1 Foundations Installation		147,258	7,679,063	5,695,630	440,045	1,683,205	2,073,061	0	17,571,003
Subtota	13-6-503 - F-3 Painting & concrete coatings		1,144	0	0	0	0	285,960	0	285,960
Subtota	13-6-504 - S-1 Pre-engineered Bldgs		2,055	0	0	0	0	410,475	0	410,475
Subtota	13-6-505 - S-2 Ductwork		137,813	9,821,608	6,057,655	1,529,266	1,522,514	0	2,135,988	21,067,031
Subtota	13-6-506 - Ductwork Support Steel & Misc Steel		27,557	1,241,103	2,494,072	300,086	330,621	1,234,800	0	5,600,681
Subtota	13-6-507 - Caisson		1,188	0	0	0	0	596,040	0	596,040
Subtota	13-6-508 - Deep Excavation & Fdn for RR car unloader		27698	0	0	0	0	5539600	0	5539600
Subtota	13-6-901 - Chimney		34,065	0	0	0	0	13,083,300	0	13,083,300
Subtota	15-6-501 - Material Handling Systems		111,500	0	0	0	0	44,828,750	0	44,828,750
Subtota	15-6-502 - M-1 BOP Mech Equip & Piping		51,767	2,782,309	527,697	128,854	418,664	2,206,368	5,481,657	11,545,550
Subtota	15-6-505 - Duct Insulation		23,340	0	0	0	0	3,057,540	0	3,057,540
Subtota	17-6-501 - E-1 Elect Pwer Dist & Control System - BOP		66,365	4,187,885	2,250,277	132,684	545,291	0	6,125,981	13,242,118
Subtota	17-6-502 - E-2 Elect Pwr Dist & Control System - Grd & U/G		20,621	1,109,147	201,066	42,333	879,380	0	0	2,231,926
Subtota	21-6-403 - Waste Water Treatment System		56,000	0	0	0	0	15,000,000	0	15,000,000
Subtota	21-6-501 - FGD System		400,000	0	0	0	0	100,054,860	0	100,054,860
	TOTAL DIRECT COST	-	1,166,196	28,683,159	18,888,511	2,732,406	7,484,072	193,996,887	13,743,626	265,528,661
	INDIRECT COSTS									
Subtota	31-6-501 - Construction Services		81,535	3,590,881	0	97,995	1,199,444	1,291,300	0	6,179,621
	14PM17101 - Startup Spares, Supplies, Equip, etc.	1.00 LS	0	0	0	0	311700	0	0	311700
	15PM00100 - Construction Management	1.00 LS	0	0	0	0	10378108	0	0	10378108
	15PM00101 - Construction Management - Inidrects	1.00 LS	0	0	0	0	1523555	0	0	1523555
	15PM00500 - Home Office Engineering & Design	1.00 LS	0	0	0	0	20514556	0	0	20514556
	15PM00110 - Startup (WGI)	1.00 LS	0	0	0	0	1238637	0	0	1238637
	15PM00115 - Startup HO Support WGI)	1.00 LS	0	0	0	0	395248	0	0	395248
	15PM00200 - Growth	1.00 LS	31,789	1,496,609	1,493,009	181,874	277,626	869,561	49,739	4,368,419
	17PM00500 - Escalation	1.00 LS	0	0	0	0	22,984,858	0	0	22,984,858
	17PM00600 - Contingency	1.00 LS	0	0	0	0	14,723,703	-	-	14,723,703
	18PM00500 - G & A	1.00 LS	0	0	0	0	1330576	0	0	1330576
	18PM00510 - Project Fee (WGI)	1.00 LS	0	0	0	0	2661152	0	0	2661152
	18PM00515 - Project Fee Incentive	1.00 LS	0	0	0	0	1330576	0	0	1330576
	TOTAL INDIRECT COSTS		113,324	5,087,491	1,493,009	279,870	78,869,739	2,160,861	49,739	87,940,709
	TOTAL WASHINGTON SCOPE		1,279,520	33,770,650	20,381,521	3,012,275	86,353,812	196,157,748	13,793,365	353,469,370

N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-5
Witness William H. Smagula
DO NOT REMOVE FROM FILE

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request STAFF-02
Dated: 08/30/2012
Q-STAFF-002

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

Question:
With respect to the increase in estimated costs of the scrubber project to $457 million announced in 2008:

a. Please provide copies of all (i) communications, information and data of any kind and in any form presented at any time by any person, including but not limited to employees and outside consultants, to any PSNH or NU-affiliated management person(s) or board of directors/trustees (including but not limited to management and directors' committees and councils), including but not limited to power point presentations, documents, reports, analyses, evaluations and opinions, in any way concerning approving the $457 million estimate, making a decision about whether or not to proceed with the scrubber project, or otherwise reacting to the increase in estimated costs.

b. Please also provide copies of all minutes or other record of decisions by any PSNH or NU-affiliated management person(s) or board of directors/trustees (including but not limited to management and directors' committees and councils) in any way concerning making a decision about whether or not to proceed with the scrubber project or otherwise reacting to the increase in estimated costs.

Response:
On June 25, 2008, NU corporate management at a meeting of the Risk and Capital Committee was provided a detailed project description at an estimated cost of $457M for the purpose of capital project review and approval. The minutes of that meeting are attached. NU corporate management recommended approval of the project by the NU Chairman and CEO. The presentation to the Risk and Capital Committee as well as the presentation provided to the Board of Trustees at the July 14, 2008 meeting are both provided. Although both documents were labeled as confidential documents protected from disclosure by the attorney-client privilege, PSNH waives the privilege in this specific instance to facilitate the review of this project. On July 14, 2008, NU Board of Trustees approved the $457M for Merrimack Clean Air Project Estimate. PSNH Senior Management obtained NU corporate management approval of an advanced in-service date for the project of mid 2012. The recommendation and approval are attached.

Long
EXHIBIT NO. 5
9/16/13
S. ROBIDAS

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, June 25, 2008)

RECOMMEND APPROVAL OF CAPITAL FUNDING FOR THE PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE CLEAN AIR PROJECT BY THE CEO OF NU AND THE CHAIRMAN OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Mr. Long directed the Committee's attention to the presentation entitled "Public Service Company of New Hampshire Clean Air Project" (the Clean Air Project) included in the material for the meeting and filed with the records thereof. He then reviewed the New Hampshire Mercury Reduction Act that mandates compliance to mercury emissions standards, and specifies the installation of scrubber technology at Merrimack Units 1 and 2 no later than July 1, 2013. The law stipulates that Public Service Company of New Hampshire (PSNH) must achieve no less than a removal of total mercury resulting in 80% capture of the total amount of mercury contained in the coal burned at all of PSNH's coal-fired units, which includes Schiller Station. Prior RaCC reviews of the Clean Air Project include a conceptual review on April 18, 2007, approval of an initial capital funding request on May 30, 2007, and approval of a revised initial capital funding request of $10 million and up to $35 million of commitment authority on September 24, 2007. An update on the Clean Air Project's schedule, cost, engineering activities, risk assessment and an economic analysis was also provided to the Committee on April 25, 2008.

Mr. Long stated that PSNH management is now seeking approval of funding for the entire Clean Air Project, currently estimated at $457 million, inclusive of funds spent to date. He noted that the cost estimates have been defined by a competitive bidding process, and that prices have escalated from original estimates made in 2006 due to much higher raw material pricing and higher costs of engineering services. The bid proposals indicate that an in-service date of mid-2012 is achievable if two key contracts can be given a limited notice to proceed by June 30. The earlier in-service date reduces the cost of the allowance for funds used during construction, and would allow

PSNH to take advantage of incentives built into the New Hampshire legislation for "early reductions" of mercury. Mr. Long stated that despite the capital cost increases, the Clean Air Project remains economic for customers. The continued operation of Merrimack Station with a scrubber will maintain fuel diversity and security of domestic fuel supply in the region, while providing PSNH customers with low cost energy. Messrs. Long and Vancho then reviewed the components of the $457 million cost estimate, including contingencies of $53 million, the cash flow and earnings projection, financial sensitivities, financial scenarios and key financial takeaways. During the review of the presentation, the Committee raised questions and discussed risks and other matters of concern. It was indicated that according to the Capital Approval Policy, since this project was greater than $50 million it would require Board of Trustees review at the July Board meeting. Messrs. Robb and Shivery left the meeting during this discussion.

After discussion, and upon motion made and seconded, the following preamble and resolutions were unanimously adopted:

WHEREAS, Public Service Company of New Hampshire ("PSNH") management provided the Committee with a capital project approval proposal for the PSNH Clean Air Project and have requested $457 million of capital funding, inclusive of funds spent to date; and

WHEREAS, this Committee has reviewed said proposal;

NOW THEREFORE, BE IT

RESOLVED, that this Committee finds the following capital funding by Public Service Company of New Hampshire ("PSNH") of the PSNH Clean Air Project as described in the material submitted to this meeting and ordered filed with its records thereof acceptable.

Project	Total Cost	Year of Completion
PSNH Clean Air Project	$457 million, inclusive of funds spent to date	2012

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, June 25, 2008)

RESOLVED, that this Committee recommends that the Chairman of the Board, President and Chief Executive Officer of Northeast Utilities and the Chairman of PSNH approve the capital funding by PSNH of the PSNH Clean Air Project, provided however that this Committee further recommends that a status update on the project be submitted to the Committee no less frequently than quarterly and the capital funding by PSNH set forth above shall not be exceeded without prior approval by the Committee.

Mrs. Kuhlman and Messrs. Hitchko, Large, Long and MacDonald left the meeting at this point.

Northeast Utilities System

Clean Air Project
Merrimack Station

Public Service Company of New Hampshire

Clean Air Project

Capital Project Review and Approval

Northeast Utilities

Risk and Capital Committee

Gary Long/John MacDonald/Jim Vancho

June 25, 2008

~~Privileged and Confidential. Prepared at the direction of counsel. Prepared in anticipation of litigation.~~

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Dated: 08/30/2012
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Executive Summary

Clean Air Project
Merrimack Station

- New Hampshire legislation mandates compliance to mercury emissions standards set forth in the NH Mercury Reduction Act
  - Wet scrubber technology will reduce power plant mercury emissions required by New Hampshire law and is the technology specified by the law
  - There is no other technology which will guarantee capture of 80% of the mercury input of our coal fleet
- Cost estimates have been defined by a competitive bidding process
  - Prices have escalated from original estimates made in 2006 due to much higher raw material pricing and higher costs of engineering service
- Bid proposals indicate that an in-service date of mid-2012 is achievable if two key contracts can be given a limited notice to proceed by June 30
  - Earlier in-service date reduces cost (AFUDC), risk, and allows PSNH to take advantage of incentives built into the New Hampshire legislation for "early reductions" of mercury
- Despite the capital cost increases, the project remains economic for customers and provides a significant investment opportunity for PSNH
  - The NPV of Revenue Requirements of adding the Scrubber versus replacing Merrimack Station energy and capacity supply with market purchases is a benefit to customers of $132 Million
  - Busbar cost increases to $94.55/MWh in 2013
  - The scrubber avoids about $15 Million in sulfur credit purchases annually, included in the customer benefit above
  - Incremental Net Income estimated at $18.5 M in 2013 – first full year of operation

Background – Merrimack Station Benefits PSNH Customers

Clean Air Project
Merrimack Station

- Merrimack Station produces 3 million MWh of low cost power annually, about 35% of PSNH's total energy service requirement. The low cost energy produced at Merrimack Station off-sets the higher cost of market purchases in the overall energy service rate
- Operating Merrimack Station in a cost-effective manner has been one of the major reasons why PSNH's energy service rate is the lowest in the region, as much as 25% lower than the average of energy service supply that we track in NE
- Merrimack Station has control technology to satisfy NOx and particulate emissions requirements. With a scrubber, SO_2 and Mercury emissions will be controlled and Merrimack will be among the cleanest coal burning plants nationally
- Coal is the most abundant domestic fossil fuel resource in the United States supplying more than 50% of the nation's power generation fleet, but only 15% of New England's generation. Maintaining the use of this secure fuel resource is important for the diversity of the region's future energy supply
- Historically, coal has maintained a significant price advantage over oil or natural gas as fuel for the power generation sector. Operated as Regulated Generation, this cost savings flows directly to customers

Continued operation of Merrimack Station with a scrubber will maintain fuel diversity and security of domestic fuel supply in the ISO-NE region, while providing PSNH's customers with low cost energy.

Background - NH Clean Power Act

Clean Air Project
Merrimack Station

- The NHCPA, in 2002, was the first four-pollutant bill in the nation (SO_2, NOx, Mercury and CO_2)
- The New Hampshire Mercury Reduction Act, enacted in 2006, was the mercury reduction next-step envisioned by the original NHCPA
- The law was developed in a collaborative effort with PSNH, representatives from the environmental community, and the Executive and Legislative branches of state government
- The New Hampshire Mercury Reduction Act specifies the installation of scrubber technology at Merrimack 1 and 2 no later than July 1, 2013
- The law stipulates that PSNH must capture a minimum of 80% of the total amount of mercury contained in the coal burned at all of PSNH's coal-fired units (Merrimack and Schiller)
- Installation of scrubber technology holds the added benefit of significantly reducing SO_2 emissions from the Merrimack Station boilers (anticipated to be 90% reduction or greater)

The New Hampshire Mercury Reduction Act Specifics:

Clean Air Project
Merrimack Station

- "It is in the public interest to achieve significant mercury emissions reductions at the coal-burning electric power plants in the state as soon as possible. The requirements of this subdivision will prevent, at a minimum, 80 percent of the aggregate mercury content of the coal burned at these plants from being emitted into the air by no later than the year 2013"
- "The Department of Environmental Services has determined that the best known commercially available technology is a wet flue gas desulphurization system…as it achieves significant emissions reduction benefits, including but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter and improved visibility (regional haze)"
- "The owner of the affected coal burning sources shall work to bring about early reductions (of mercury emissions) and shall be provided incentives to do so"
- "The installation of scrubber technology will not only reduce mercury emissions significantly but will do so without jeopardizing electric reliability and with reasonable costs to consumers"
- "The installation of such technology is in the public interest of the citizens of New Hampshire and the customers of the affected sources"
- "The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of costs, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components"

Estimate of Project Costs

Clean Air Project
Merrimack Station

Direct Project Costs

➢ Major Contract Islands: (firm price bids)	
• FGD System	$100M
• Material Handling	$45M
• Waste Water Treatment	$15M
• Chimney	$13M
➢ PSNH Project Costs	$30M
➢ Program Manager Costs (URS Washington Group)	
• Balance of Plant & Interconnection	$93M
• Engineering and Construction Management	$59M
TOTAL DIRECT PROJECT COSTS	**$355M**

➢ PSNH Project Contingency	$10M
➢ Program Manager Contingencies	
• Materials Escalation	$23M
• Contingency	$15M
• Scope Growth	$ 4M
TOTAL PROJECT CONTINGENCIES	**$53M**

➢ Power Advocate's Defined Costs Savings	
• Project cost deduction	($6M)
➢ Anticipated Value Engineering*	
• Scope reduction	($5M)
TOTAL ANTICIPATED COST REDUCTIONS	**($11M)**

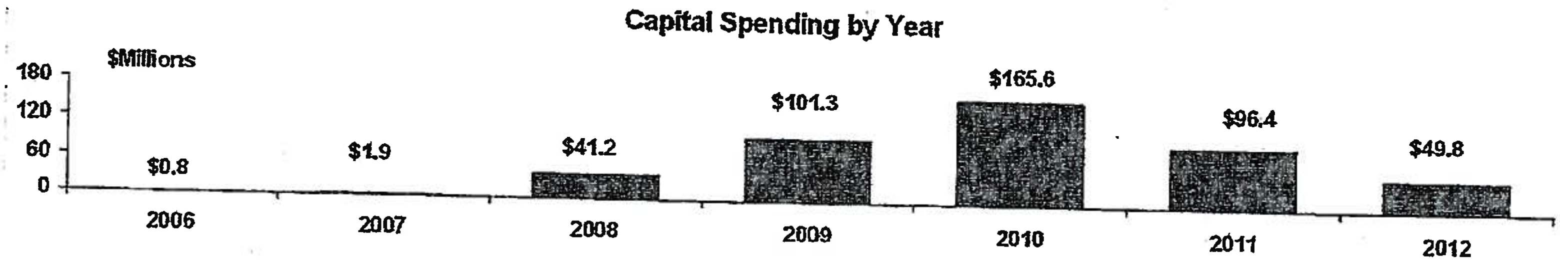
➢ NU Corporate Costs	
• AFUDC	$55M
• Indirect Costs	$5M
TOTAL CORPORATE COSTS/AFUDC	**$60M**

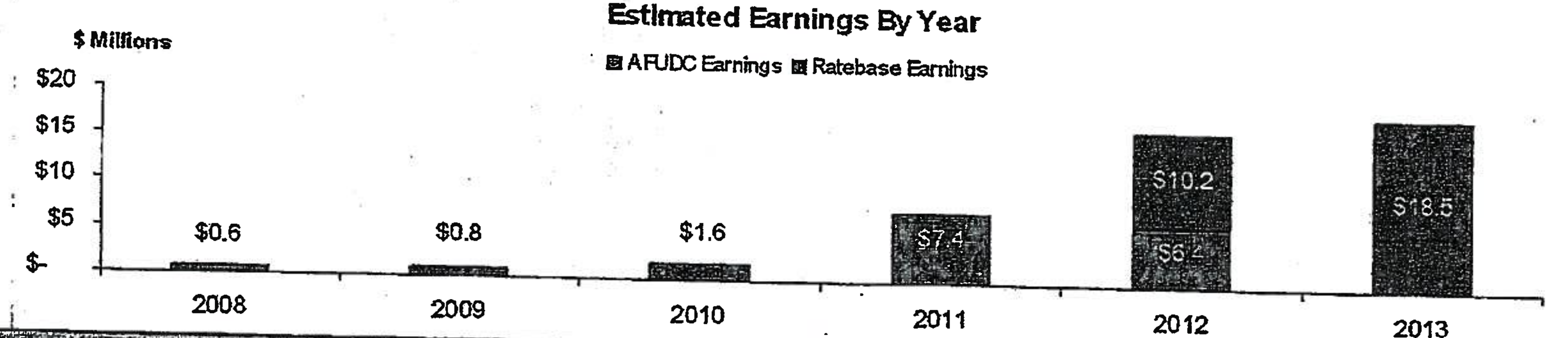
Total Project Cost Estimate = $457M

*Note: Alternative material handling proposal in consideration that would reuse existing station equipment and reduce project costs by about $5M

Cashflow and Earnings Projection

Clean Air Project
Merrimack Station





EPS	$.00	$.00	$.01	$.02	$.03	$.04

Assumptions:

- Base-case project costs are estimated at $457M
- Project expected to be in-service on June 30, 2012
- Assumes 9.81% ROE on 47.23% of Capital Structure
- Average Shares outstanding per 2009-2013 Forecast

Financial Sensitivities

- Base-case assumptions result in net customer benefit of \$132 Million and a 2013 busbar cost of \$94.55
- Net customer cost is most sensitive to expected future natural gas and coal prices

Assumption Category	Assumptions			2008 PV of Net Customer Cost 2012-2027 ($Mil)	2012 Plant Busbar Cost ($/MWh)
	Downside	Base	Upside	($225) ($175) ($132) ($100) $0	$91 $92 $93 $94.55 $96 $97 $98
Capital Cost	+10%	[illegible] mil	-10%	($159) ($27) $27 ($105)	$92.31 (2.24) $2.24 $96.79
2012 gas Prices, MMBTU[3]	-5%	$11.00	+5%	($213) ($81) $81 ($51)	
2012 coal prices, MMBTU[3]	+5%	$4.82	-5%	($180) ($48) $48 ($84)	$92.02 (2.53) $2.53 $97.08
2012 RGGI/Federal carbon costs per Ton[2,3]	+50%	[illegible]	-50%	($158) ($26) $26 ($106)	$92.53 (2.02) $2.02 $96.57

White text in bars represents change in values;
Black text beside bars represents sensitivity result.

Notes:

1. NPV Net Customer Cost = (2008 Present Value of Merrimack Plant Revenue Requirements from 2012 to 2027) minus (2008 Present Value of Market Energy plus 2008 Present Value of Capacity Payments from 2012 to 2027).
2. Amounts presented reflect RGGI/federal (Lieberman-Warner) cost estimates. Impacts are equivalent at given prices since RGGI does not provide for carbon allowances but federal proposals are assumed to include Merrimack allocations starting at 67% (per Lieberman-Warner).
3. Fuel and carbon costs are escalated at 2.5% per annum off of the 2012 estimate.

Financial Scenarios

Clean Air Project
Merrimack Station

	UNLIKELY LOW	POSSIBLE LOW	BASE	POSSIBLE HIGH	UNLIKELY HIGH
NPV - NET CUSTOMER COST[1]	$210 MIL	$43.4 MIL	($132 MIL)	($296 MIL)	($461 MIL)
MONTHLY RESIDENTIAL CUSTOMER COST IMPACT[4]	$1.61	$0.33	($1.01)	($2.28)	($3.54)
2013 PLANT BUSBAR COST ($/MWH)	$104.44	$100.77	$94.55	$89.52	$84.49
NET INC - 2013 (FIRST FULL YEAR IN-SERVICE)	$21.5 MIL	$20.1 MIL	$18.5 MIL	$18.1 MIL	$17.7 MIL
ASSUMED PROBABILITY	5%	25%	[illegible]	25%	5%
PARAMETERS					
CAPITAL COSTS, MILLIONS	$532	$497	$457	$447	$437
2012 GAS PRICES, MMBTU[3]	$9.90	$10.45	$11.00	$11.55	$12.10
2012 COAL PRICES, MMBTU[3]	$5.30	$5.06	$4.82	$4.58	$4.34
2012 CARBON COSTS, TON (RGGI/FEDERAL)[2,3]	$15/$45	$10/$30	$7/$21	$3.5/$10.6	$0/$0

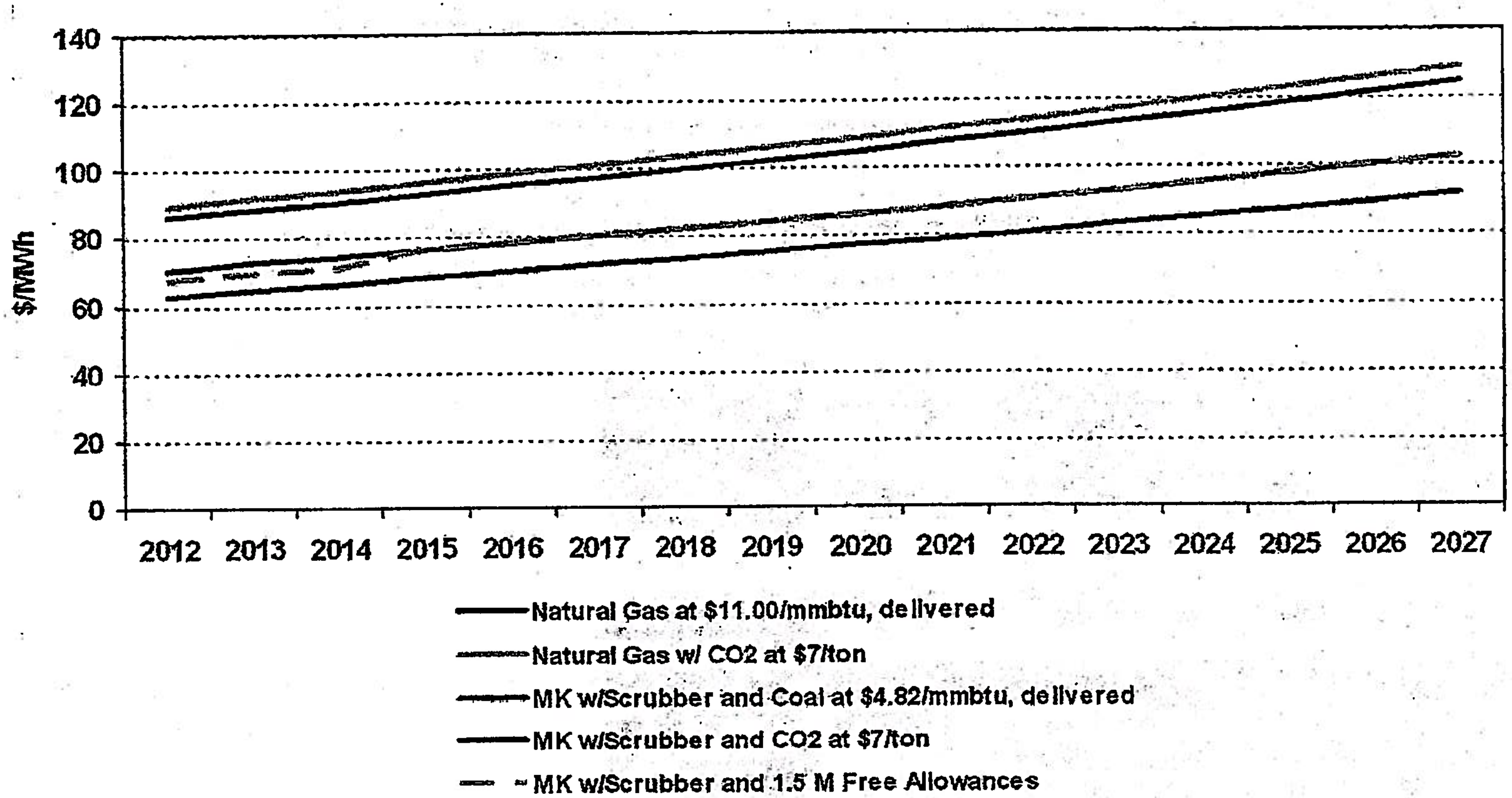
CASE LEGEND

UNLIKELY LOW	CASE REFLECTS PROJECT IN-SERVICE DELAYED ONE YEAR AND COST OVERRUN ($45M), COOLING TOWER ADDITION ($30M), MINIMAL GAS/COAL SPREAD
POSSIBLE LOW	CASE REFLECTS PROJECT IN-SERVICE ON-TIME WITH COST OVERRUN ($10M), COOLING TOWER ADDITION ($30M), DECREASED GAS/COAL SPREAD
BASE	CURRENT ASSUMPTIONS
POSSIBLE HIGH	CASE REFLECTS PROJECT IN-SERVICE 6 MONTHS EARLY ($10M), PROJECT COSTS AS EXPECTED, BENIGN CARBON LEGISLATION, INCREASED GAS/COAL SPREAD
UNLIKELY HIGH	CASE REFLECTS PROJECT IN-SERVICE 6 MONTHS EARLY ($10M) WITH LOWER THAN EXPECTED COSTS ($10M), NO CARBON LEGISLATION, MAXIMUM GAS/COAL SPREAD

1. NPV Net Customer Cost = (2008 Present Value of Merrimack Plant Revenue Requirements from 2012 to 2027) minus (2008 Present Value of Market Energy plus 2008 Present Value of Capacity Payments from 2012 to 2027).
2. Amounts presented reflect RGGI/federal (Lieberman-Warner) cost estimates. Impacts are equivalent at given prices since RGGI does not provide for carbon allowances but federal proposals are assumed to include Merrimack allocations starting at 67% (per Lieberman-Warner).
3. Fuel and carbon costs are escalated at 2.5% per annum off of the 2012 estimate.
4. Based on NPV Net Customer Cost levelized over the period 2012-2027, and average residential usage of 500 kWh per month.

Economic Analysis Supports That Merrimack Station With Scrubber Will Be Dispatched

Clean Air Project
Merrimack Station



- Natural Gas plant heat rate of 7,620 Btu/kWh in a Combined Cycle unit
- SO_2 at $500/ton, NOx at $1,300/ton

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Key Financial Takeaways

Clean Air Project
Merrimack Station

- Customer value of scrubber installation extremely sensitive to future expected natural gas/coal price spread
  - At assumed 2012 price levels and other base case parameters, a spread of approximately $5.29/mmbtu (escalating) is required to create customer benefits
- Impact of RGGI/Federal carbon legislation is not expected to render scrubber investment uneconomic to customers at current projected costs
  - Assumes any Federally imposed carbon legislation would grant carbon allowances to generators (approximately 67% of Merrimack's requirement)
  - Absent Federal allocations (or under RGGI), assuming all other base case assumptions, a 2012 carbon cost of $30/ton (escalating) or greater would eliminate customer value of scrubber installation
- Assuming base case fuel and carbon assumptions, capital cost estimates have meaningful headroom before rendering investment uneconomic
  - However, reductions in natural/gas coal spread and increases in carbon costs would put pressure on ability to construct within the current projection

Investment is essentially a long spread position on natural gas/coal with carbon and construction risk

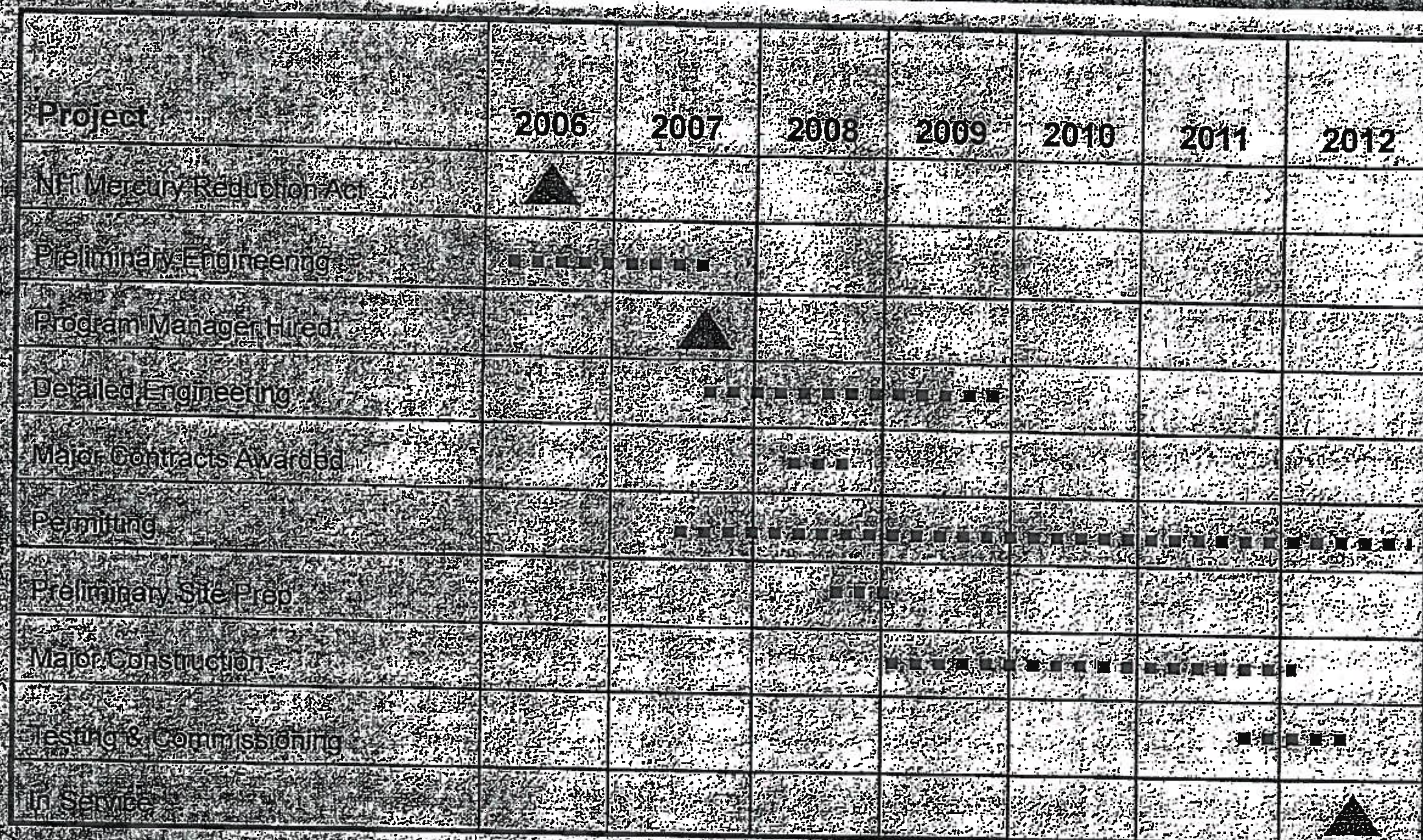
Project Benefits are Accentuated by Advancing the In-Service Date to mid-2012

Clean Air Project
Merrimack Station

- Financial
  - Reduces AFUDC cost by $10 Million
  - Limits exposure to material or labor cost escalation for project elements not covered by firm price contracts
  - Generates real earnings one year sooner
- Environmental
  - Eliminates an additional 31,350 tons of SO_2
  - Eliminates an additional 229 pounds of Mercury
  - Reduces particulate emissions to less than 1% one year sooner
- Customer
  - Produces "early reduction mercury credits" that can be used for
    - Compliance in future years if operational issues with the scrubber arise
    - Conversion to fungible SO_2 allowances (estimated at 12,500 allowances)

Revised Project Schedule

Clean Air Project
Merrimack Station



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Regional Barriers to Adding New Base Load Generation in New England Cause Merrimack to be Strategically Positioned for Re-Investment

Clean Air Project
Merrimack Station

- New base load power plants (coal, nuclear, IGCC) are not on the near or mid-term horizon for the region, making re-investment in environmental technology at existing assets the necessary strategy to maintain appropriate base-load supply
- Current market players are engaged in blocking opportunities for new, lower cost, regulated generation assets, making preservation of existing assets increasingly important
- ISO-NE market rules, and the current economic climate, make it nearly impossible for prospective generators to secure financing and overcome the substantial "barriers to entry" to build new generation in the region
- New England electric energy supply is highly dependent on natural gas, and costs are subject to corresponding commodity price volatility, and long-term price increases
- In addition to the support these barriers provide for continued operation of existing base-load plants:
  - Brattle Group analysis of future NE energy markets indicates that all coal generation, including Merrimack, will continue to operate economically
  - Operation of Merrimack Station on coal provides stability to the power supply in the region
  - Loss of PSNH's Merrimack Station would call into question the viability of operating the remaining generating assets as a fleet

Conclusion

Clean Air Project
Merrimack Station

- Installation of the scrubber is required by NH law to meet mercury emissions requirements
- Merrimack Clean Air Project capital costs have increased significantly since the original project costs estimates were prepared in 2006, and stand at $457M
- Under the base case and with varying assumptions, continued operation of Merrimack Station with the Clean Air Project remains economically beneficial for customers
- State law allows for recovery of prudently incurred costs to construct and operate the scrubber
- The project team is in place and prepared to execute contracts now and begin construction in earnest late this year, with a project in-service date of mid-2012
- The proposal to construct and operate a scrubber at Merrimack Station, in conformance with the NH Mercury Reduction Law, is in the best interest of PSNH's customers and shareholders

Northeast Utilities System

Clean Air Project
Merrimack Station

Appendix Materials

PSNH Clean Air Project

June 25, 2008

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Risk Assessment, Major Risk Concerns

Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Remaining bids received from vendors are significantly higher than expected related to material and handling costs. Note: The bids on the major equipment have been received.	2008	$10 million	20%	$2 million	Currently carrying out the procurement schedule. The Purchasing area is trying to stimulate competition during the bid process. Lastly as the required implementation date allows for some slippage in the schedule.
Lack of sufficient, qualified construction labor results in increased costs to import labor resources, schedule delays to wait for resources to become available.	2009-12	$50 million	10%	$5 million	WGI will initiate the National Maintenance Agreement. Meetings have been held with the union trades to discuss the project and labor requirements up front.
Inability to lock in firm prices during contracting phase exposes the project to price volatility and currency risk.	2008-9	$25 million	20%	$5 million	The RFP is being structured for fixed/lump sum pricing. The contract will be negotiated to try and include these parameters.

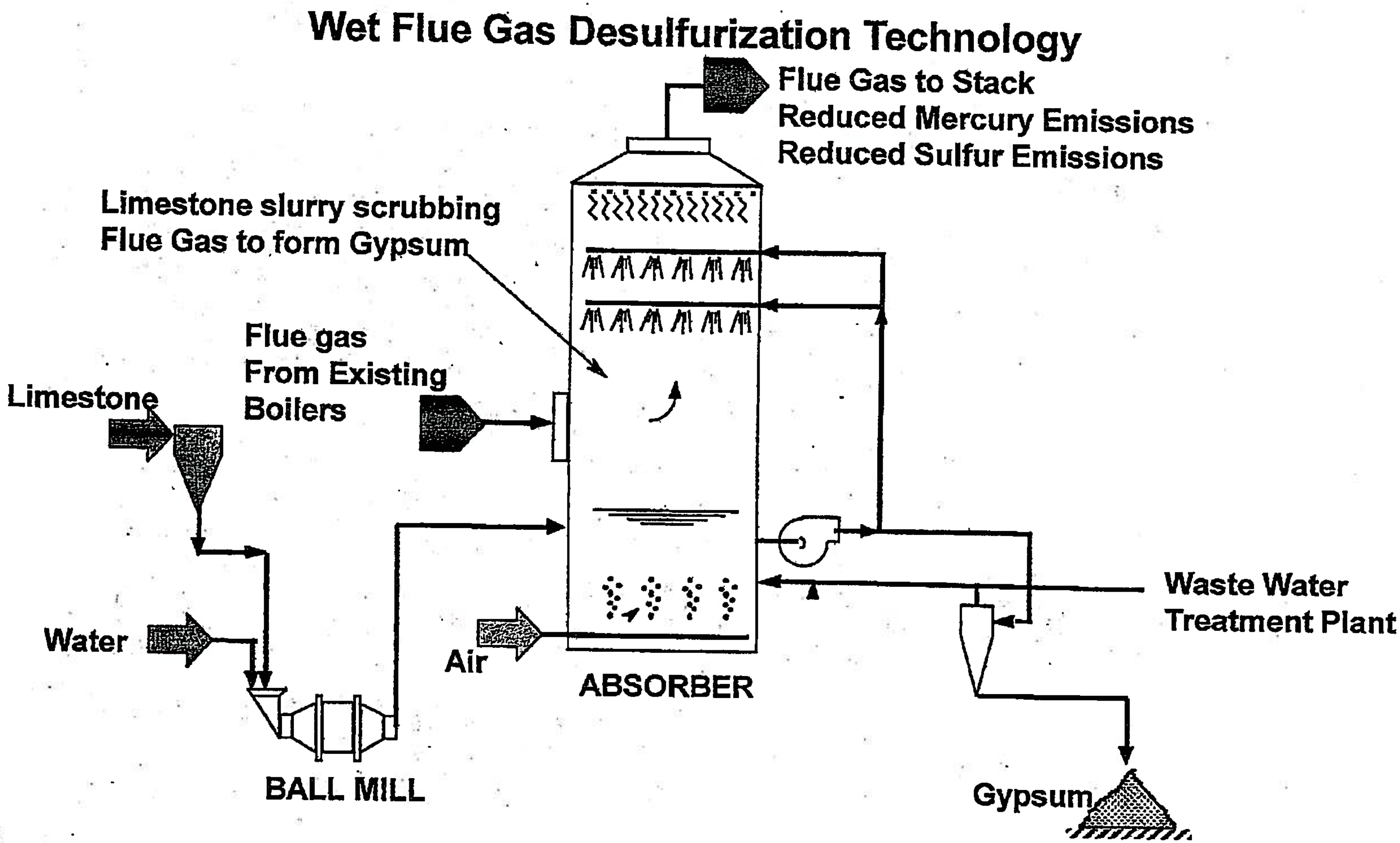
Risk Assessment, Major Risk Concerns

Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Vendors unable to meet project design criteria resulting in non-conforming bids. Note: bids received with mercury criteria. Risk relates to remaining design specifications.	2008-9	$25 million	25%	$6.25 million	In the event this occurs, an acceptable outcome will be negotiated during the procurement process.
Inability to design appropriate plant integration plans resulting in MK1 bypass, boiler implosion and noise issues.	2008-9	$12.5 million	50%	$6.25 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.
Scope definition changes drastically during construction resulting in additional expenditures and/or potential schedule delays.	2008-12	$18.75 million	20%	$3.75 million	PSNH team will work closely with WGI & EPC contractors to minimize the impact.
Proposed design is inadequate and does not meet operability/reliability/ constructability requirements resulting in complete redesign.	2008-9	$12.5 million	30%	$3.75 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.

Scrubber Schematic

Clean Air Project
Merrimack Station



Merrimack Station: 2008

Clean Air Project
Merrimack Station

Northeast Utilities System

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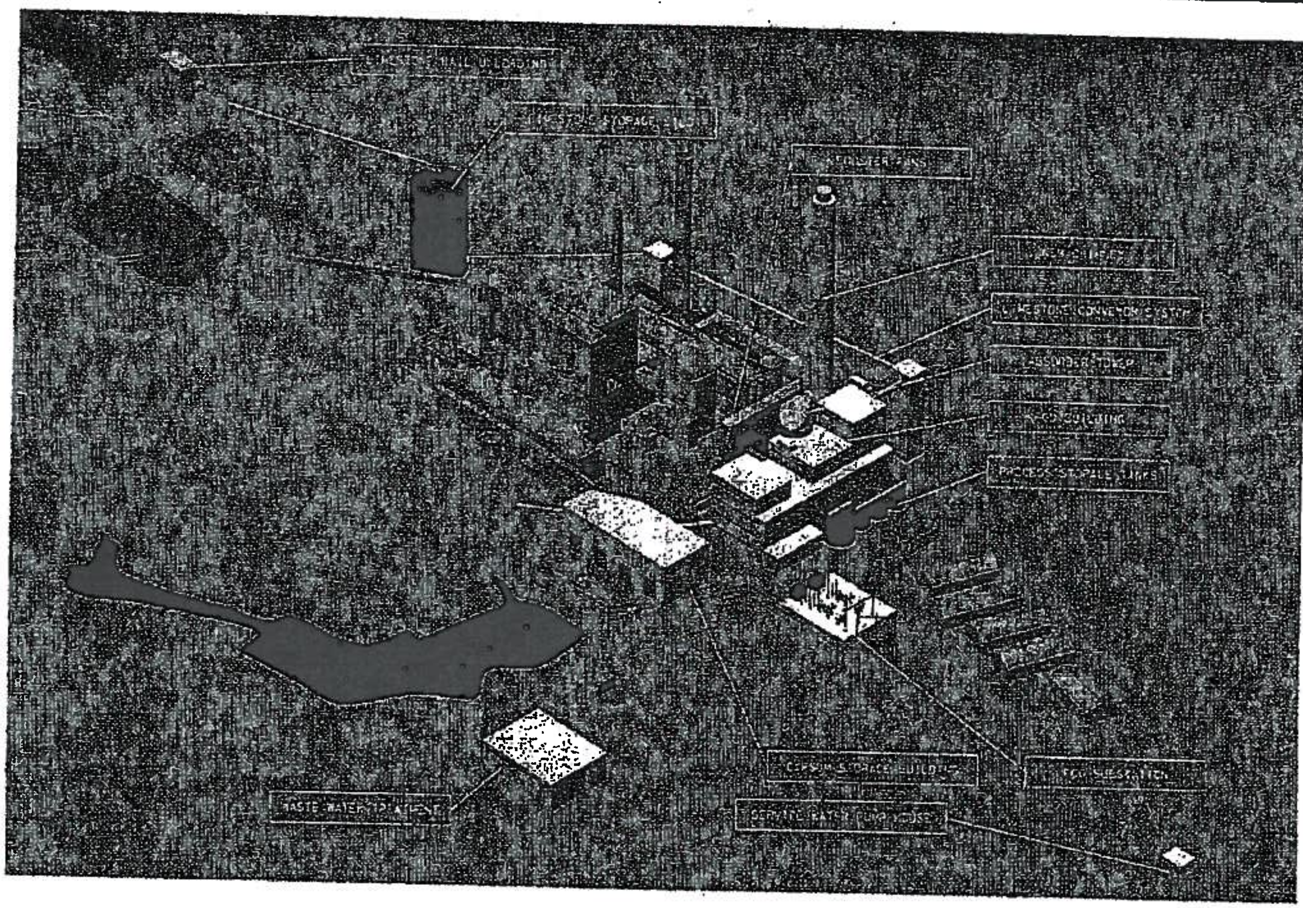
Merrimack Station: 2013

Clean Air Project
Merrimack Station



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Clean Air Project
Merrimack Station

Project Organization

Corporate Leadership/Board

Board Approval
RaCC Approval

PSNH Leadership

RMC/ERMC Approval

Project Director
William Smagula

Project Manager Michael Hitchko

Corporate Project Support Team
Purchasing – Rick Osak
Legal – Bob Bersak
Enviro/Reg – Lynn Tillotson
Insurance – Dave Orpik
Treasury

Site Project Team
Project Engineer - Richard Roy
Station Liaison
Project Administrator
Administrative Assistant

Merrimack Station
Manager - Harold Keyes

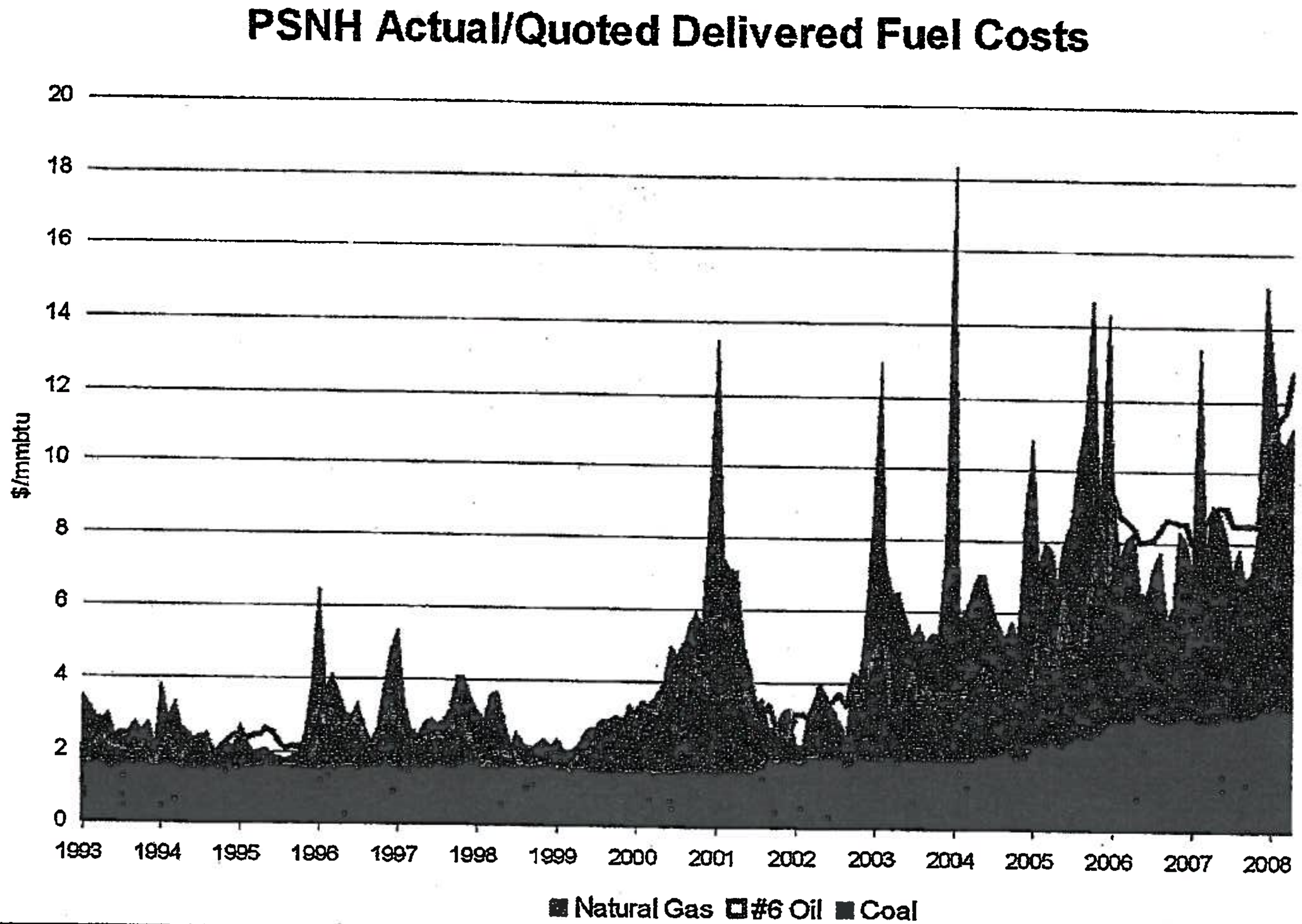
Operations
Maintenance

Program Manager
Engineering, Procurement
And Construction Management (EPCM)
Team with PSNH for Engineering and
Construction Management

Scrubber Island	Material Handling Island	Chimney	Civil	Major Mechanical	Electrical Controls

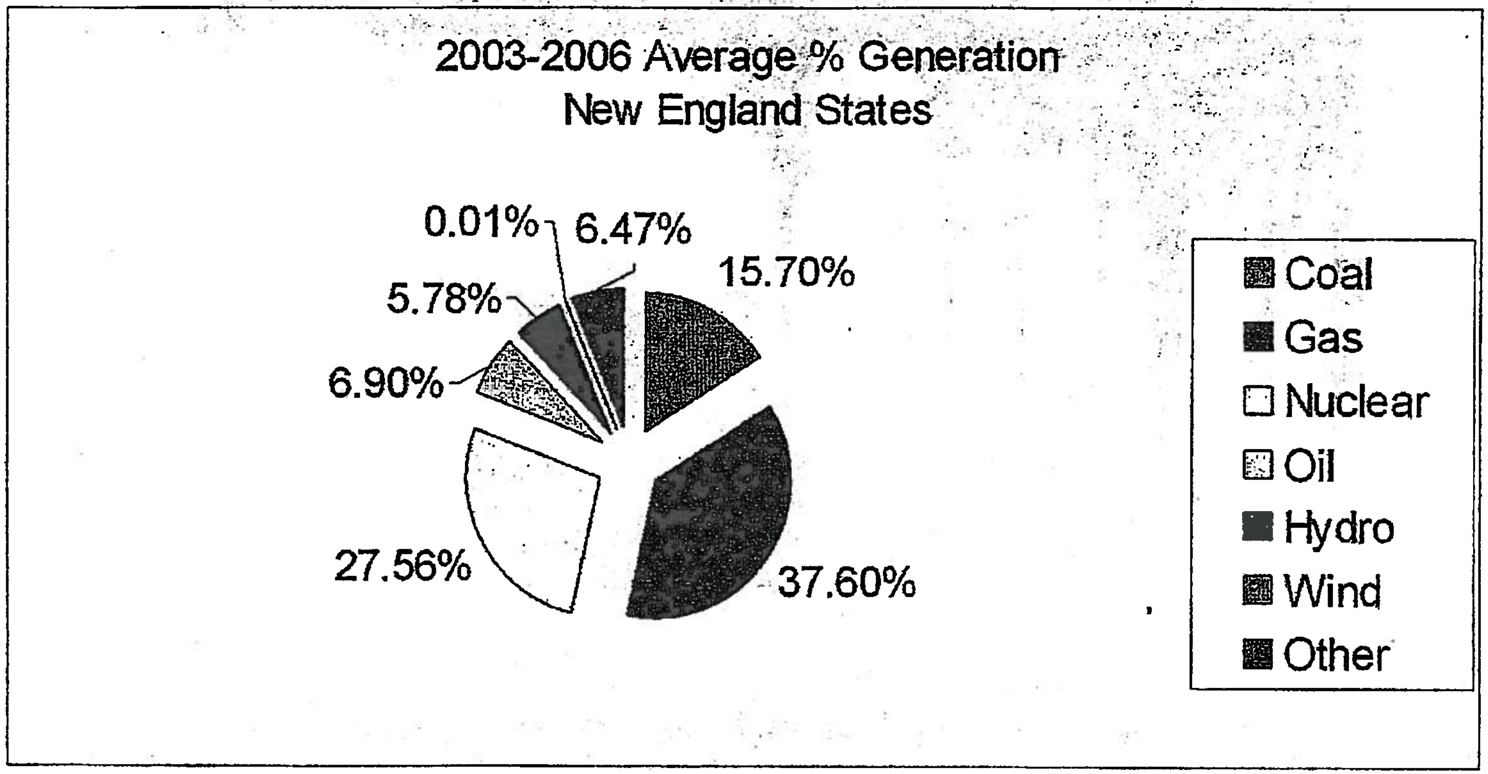
Historic Price Volatility Suggests Coal Will Find a Way to be Cheaper than Alternatives

Clean Air Project
Merrimack Station



ISO-NE Energy Supply by Fuel Type

Clean Air Project
Merrimack Station



Northeast Utilities System

Clean Air Project
Merrimack Station

Public Service Company of New Hampshire

Clean Air Project

Capital Project Review and Approval

Northeast Utilities

Board of Trustees

Gary Long/Cameron Bready

July 15, 2008

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Clean Air Project
Merrimack Station

Executive Summary

- New Hampshire legislation mandates compliance to mercury emissions standards set forth in the NH Mercury Reduction Act
  - Wet scrubber technology will reduce power plant mercury emissions required by New Hampshire law and is the technology specified by the law
  - There is no other technology which will guarantee capture of 80% of the mercury input of our coal fleet
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Background – Merrimack Station Benefits PSNH's Customers

Clean Air Project

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- Historically, coal has maintained a price advantage over oil or natural gas as fuel for the power generation sector. Operated as Regulated Generation, this cost savings flows directly to customers

Continued operation of Merrimack Station with a scrubber will maintain fuel diversity and security of domestic fuel supply in the ISO-NE region, while providing PSNH's customers with low cost energy.

Financial Assessment – Summary Metrics

Total Installed Capital Costs	$457M
Capital Cost $ / kW	$1,000[1]
NPV of Base Case Customer Benefit	$132M
2013 Net Income Contribution	$18.5M
2013 EPS Contribution (Diluted)	$.04/share
Busbar Cost (2013)	$94.55/MWh

Key assumptions :

- Project In-service on June 30, 2012
- 9.81% ROE on 47.23% equity component of capital structure
- Base case natural gas price of $11/mmbtu, coal of $4.82/mmbtu and carbon of $7/ton

Note:

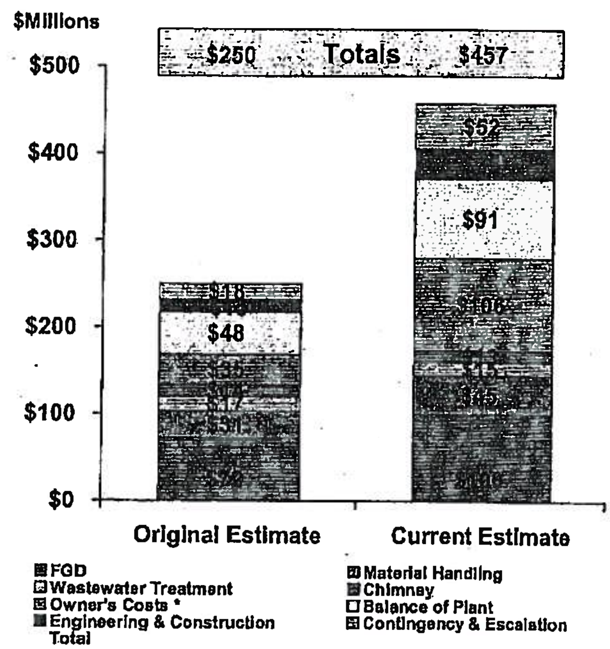
1. For reference, capital costs for a new CCGT would be approximately $1,600 - $1,700/kw. A new peaker would be approximately $950 – 1,000/kw.

Clean Air Project

Estimate of Project Costs

Major Island Contracts (Firm-Price Bids)	
FGD System	$100M
Material Handling	$45M
Waste-water Treatment	$15M
Chimney	$13M
PSNH Project Costs	$44M
Other Program Manager Costs	
Balance of Plant and Interconnection	$91M
Engineering and Construction	$35M
Contingency and Escalation	$52M
AFUDC	$57M
Total Direct Costs	**$452M**
NU Indirect Costs	**$5M**
Project Total	**$457M**

Project Costs by Component



* Includes PSNH Project Costs, Indirect Costs, and AFUDC

Clean Air Project

Financial Assessment - Overview

- Customer benefit/cost of scrubber installation is dependent upon customer alternatives for securing the energy and capacity provided by Merrimack
  - Analysis assumes that customers will procure energy and capacity from the market if Merrimack is not operational
  - Market price for energy will likely continue to be set by natural gas units for the foreseeable future
    - → Expected future price for natural gas and the spread between natural gas prices and coal prices are critical to assessment of customer impacts
- Financial customer benefit/cost determined as follows:
  - PV of net revenue requirements of Merrimack facility (including new scrubber) – PV of market energy and market capacity costs
  - Customer benefit is achieved when the revenue requirements of Merrimack are lower than the costs of procuring the energy and capacity that would otherwise be provided by Merrimack from the market
- Future impact of carbon may play an important role in determining ultimate customer benefit/cost
  - Carbon costs are expected to impact electricity rates, but coal plants will likely be disproportionally affected given their emission rates versus natural gas plants

Financial Sensitivities

Clean Air Project

- Base-case assumptions result in net customer benefit of $132 million
- Net customer benefit is most sensitive to expected future natural gas and coal prices and the relative spread between the two commodities

Assumption Category	Assumptions			2008 PV of Net Customer Cost[1] 2012-2027 ($Mil)	Net Customer Impact Break-Even Rates
	Downside	Base	Upside	($300) ($180) ($132) ($50) $40	
Capital Cost	+10%	$457 mil	-10%	$(159) [illegible] $(105)	$684 mil
2012 gas Prices, MMBTU[2]	-10%	$11.00	+10%	$(295) [illegible] $31	$10.10
2012 coal prices, MMBTU[2]	+10%	$4.82	-10%	$(228) [illegible] $(36)	$5.49
Implied Gas/coal Spread	$4.60	$6.18	$7.76	N/A[4]	$5.29[4]
2012 Carbon Costs[2,3]	+50%	$7	-50%	$(167) [illegible] $(97)	$30.13

Text in bars represents change in values;
text beside bars represents sensitivity result.

Notes:

1. NPV Net Customer Cost = (2008 Present Value of Merrimack Plant Revenue Requirements from 2012 to 2027) minus (2008 Present Value of Market Energy plus 2008 Present Value of Capacity Payments from 2012 to 2027).
2. Fuel and carbon costs are escalated at 2.5% per annum off of the 2012 estimate.
3. Reflects net impact on a $/ton basis for either RGGI or Federal policies excluding any allocations of allowances.
4. Spread not sensitized as impact depends on underlying natural gas and coal prices. Break even is based on a $4.82/mmbtu Coal Price (~$130 per delivered ton).

Financial Scenarios

Clean Air Project

- The following scenarios, denoted by their assumed probability of occurrence, demonstrate the compounding impacts of a variety of assumption changes on the key financial metrics for the project:

	Unlikely Low	Possible Low	Base	Possible High	Unlikely High
NPV - Net Customer Cost	$481 MIL	$194 MIL	($132 MIL)	($413 mil)	($719 mil)
Monthly Residential Customer Cost Impact	$3.70	$1.49	($1.01)	($3.17)	($5.52)
2013 Plant Busbar Cost ($/MwH)	$102.41	$100.37	$94.55	$87.86	$79.44
Net Income - 2013 (First full Year In-Service)	$21.5 mil	$20.1 MIL	$18.5 MIL	$18.1 mil	$17.7 mil
Assumed probability	5%	25%	-	25%	5%
Parameters					
Capital Costs, Millions	$532	$497	$457	$447	[illegible]
2012 Gas Prices, MMBTU	$8.80	$9.90	$11.00	$12.10	$13.20
2012 Coal Prices, MMBTU	$5.78	$5.30	$4.82	$4.34	$3.86
2012 Carbon Costs, Ton	$30	$20	$7	$6	$0

Case Legend

- Unlikely Low: Case reflects project in-service delayed one year and cost overun ($45M), cooling tower addition ($30M), minimal Gas/coal Spread
- Possible Low: Case reflects project in-service on-time with cost overun ($10M), cooling tower addition ($30M), decreased Gas/coal Spread
- Base: Current assumptions
- Possible High: Case reflects project in-service 6 months early ($10M), project costs as expected, benign carbon legislation, increased gas/coal spread
- Unlikely High: Case reflects project in-service 6 months early ($10M) with lower than expected costs ($10M), no carbon legislation, maximum gas/coal spread

- Other scenarios considered:

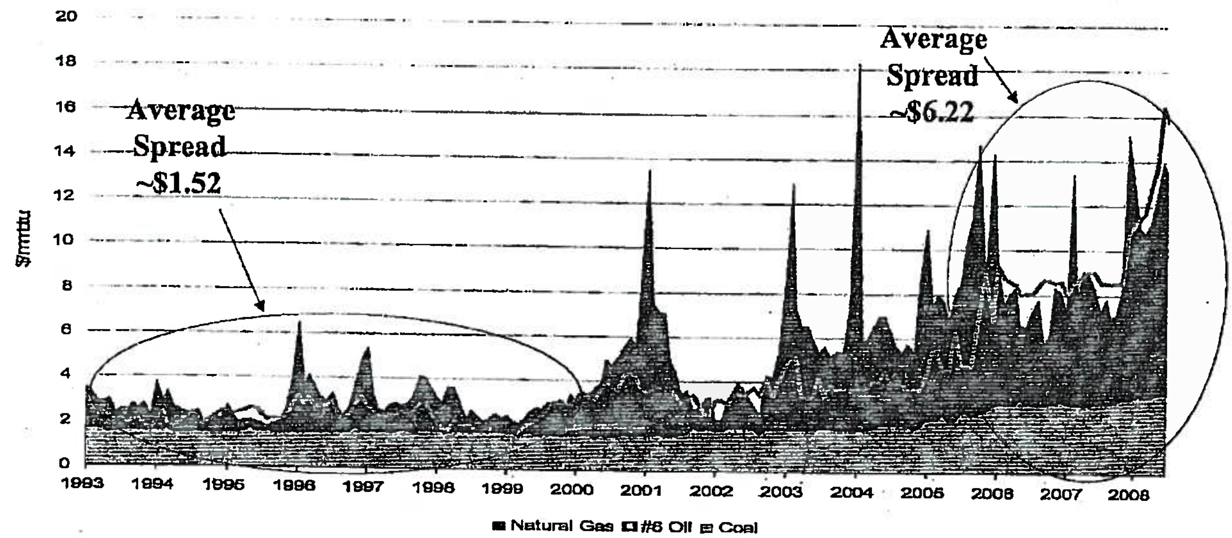
	Customer Cost/(Benefit)
• $200 Oil Scenario:	($437 million)
• $50 Carbon Cost:	$70 million

Clean Air Project

Historic Fuel Spreads

- Gas/Coal spread has averaged $3.18/mmbtu over the last 15 years, as compared to the required customer break-even level of $5.29/mmbtu (based on current price levels)
  - However, post the hurricane season of 2005, the spread has averaged $6.22/mmbtu
- Since January 2007, the spread has averaged nearly $6.63/mmbtu and current spreads are more than ~$9/mmbtu

PSNH Actual/Quoted Delivered Fuel Costs



Clean Air Project
Merrimack Station

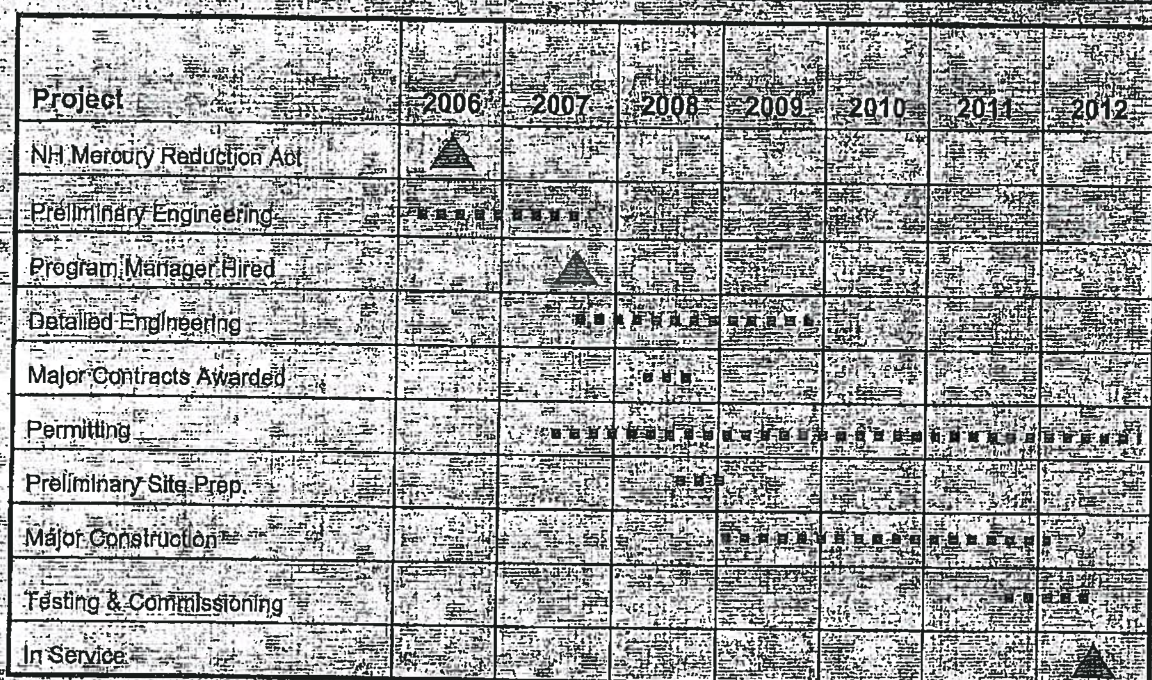
Key Financial Takeaways

- Customer value of scrubber installation extremely sensitive to future expected natural gas/coal price spread
  - At assumed 2012 natural gas and coal price levels and other base case parameters, a spread of approximately $5.29/mmbtu (escalating) is required to create customer benefits
  - Recent spreads suggest that this level is realistic; however, historic spread levels have averaged lower
- Impact of carbon legislation is not expected to render scrubber investment uneconomic to customers at current projected costs under RGGI
  - Absent allocations, assuming all other base case assumptions, a net carbon cost of $30/ton (escalating) or greater would diminish customer value of scrubber installation
- Assuming base case fuel and carbon assumptions, capital cost estimates have meaningful headroom before rendering investment uneconomic
  - All other base case assumptions being held constant, capital costs can increase to ~$684 million before eliminating customer economic benefits
  - However, reductions in natural/gas coal spread and increases in carbon costs would put pressure on base case capital cost estimates
- Generation ratemaking making structure allows for PSNH to earn 9.81% ROE on equity invested in the project under all scenarios presented
  - Assumes that project capital costs are deemed prudent

Investment is essentially a long spread position on natural gas/coal with carbon and construction risk

Revised Project Schedule

Clean Air Project
Merrimack Station



Northeast Utilities System

11

Clean Air Project
Merrimack Station

Conclusion

- Installation of the scrubber is required by NH law to meet mercury emissions requirements
- Merrimack Clean Air Project capital costs have increased significantly since the original project costs estimates were prepared in 2006, and stand at $457M
- Under the base case, continued operation of Merrimack Station with the Clean Air Project remains economically beneficial for customers
- State law allows for recovery of prudently incurred costs to construct and operate the scrubber
- The project team is in place and prepared to execute contracts now and begin construction in earnest late this year, with a project in-service date of mid-2012
- The proposal to construct and operate a scrubber at Merrimack Station, in conformance with the NH Mercury Reduction Law, is in the best interest of PSNH's customers and shareholders

Northeast Utilities System

Clean Air Project
Merrimack Station

Appendix Materials

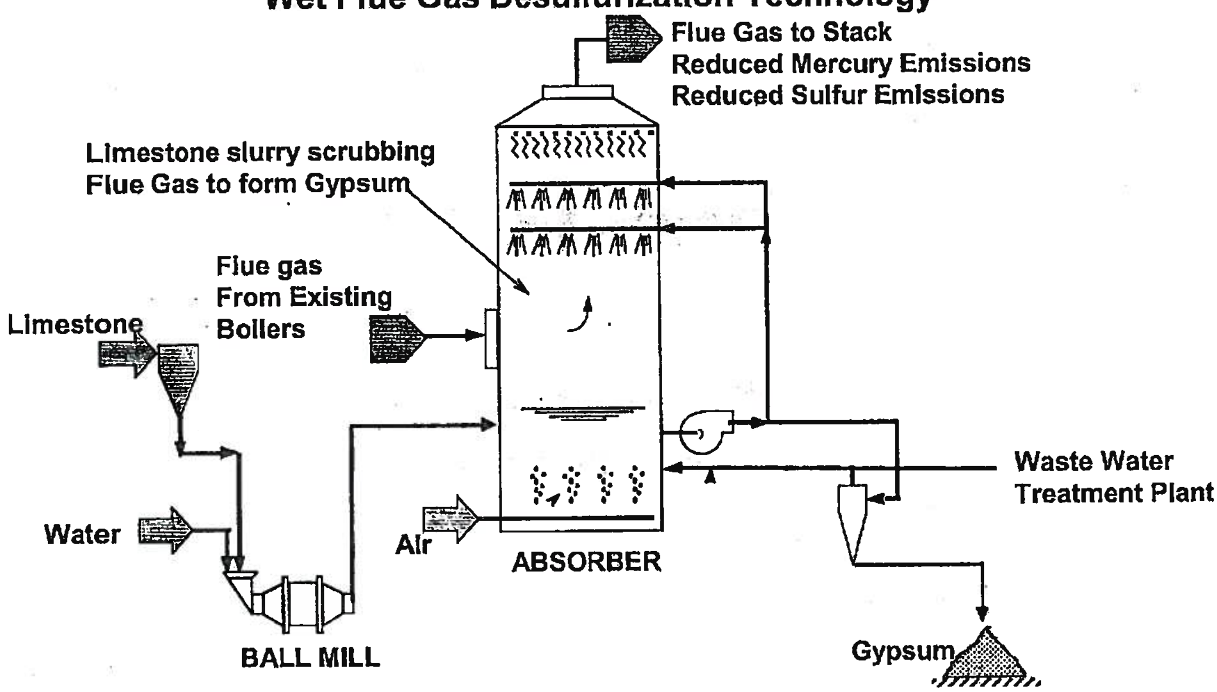
PSNH Clean Air Project

July 15, 2008

Scrubber Schematic

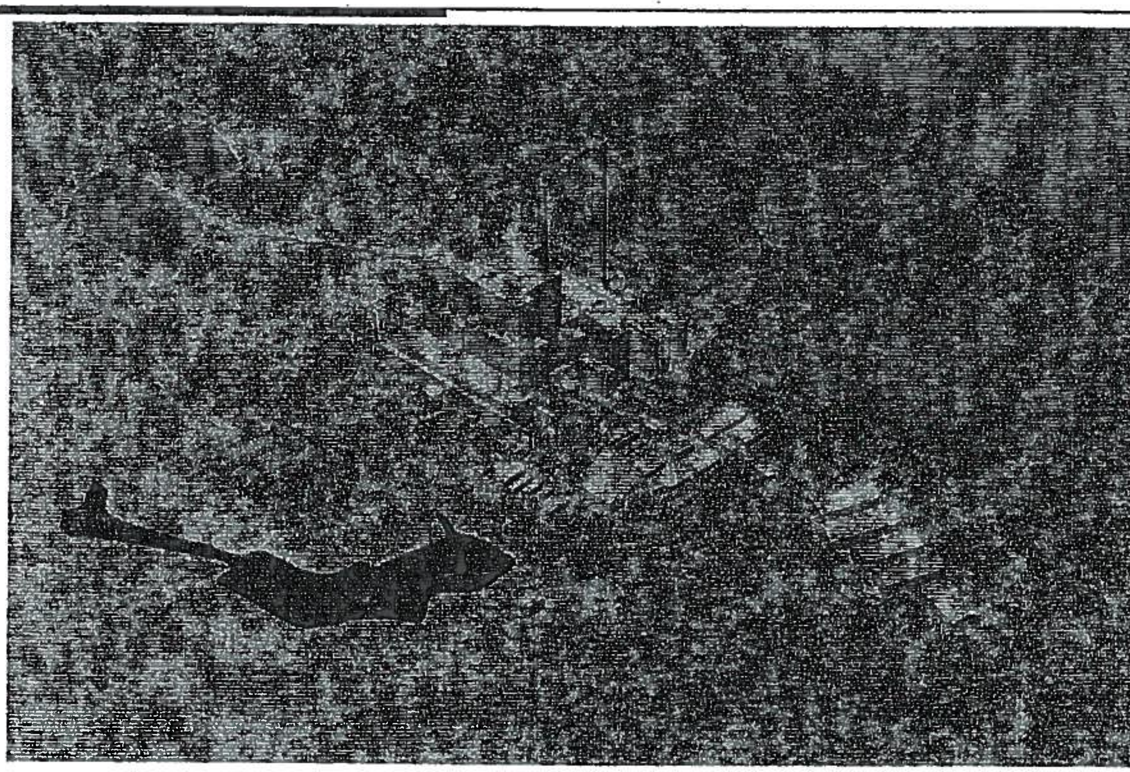
Clean Air Project
Merrimack Station

Wet Flue Gas Desulfurization Technology



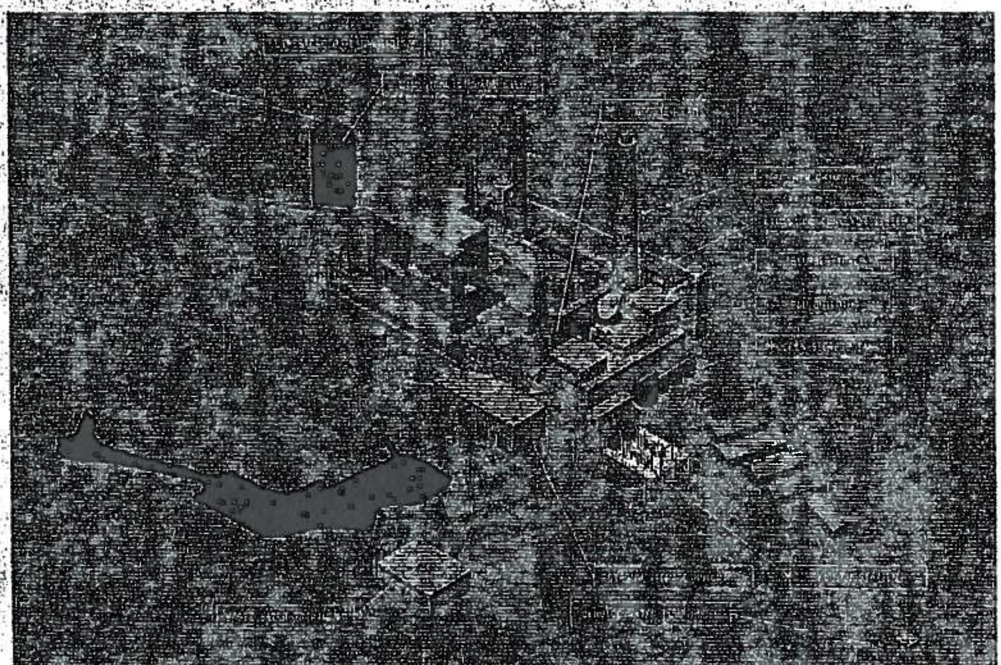
Clean Air Project
Merrimack Station

Merrimack Station: 2008



Merrimack Station: 2013

Clean Air Project
Merrimack Station



Risk Assessment, Major Risk Concerns

Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential (Project Capital) Cost Impact	Likelihood of Occurrence (%)	Expected value Capital Cost Exposure	Mitigation Plan
Remaining bids received from vendors are significantly higher than expected related to material and handling costs. Note: The bids on the major equipment have been received.	2008	$10 million	20%	$2 million	Currently carrying out the procurement schedule. The Purchasing area is trying to stimulate competition during the bid process. Lastly as the required implementation date allows for some slippage in the schedule.
Lack of sufficient, qualified construction labor results in increased costs to import labor resources, schedule delays to wait for resources to become available.	2009-12	$50 million	10%	$5 million	WGI will initiate the National Maintenance Agreement. Meetings have been held with the union trades to discuss the project and labor requirements up front.
Inability to lock in firm prices during contracting phase exposes the project to price volatility and currency risk.	2008-9	$25 million	20%	$5 million	The RFP is being structured for fixed/lump sum pricing. The contract will be negotiated to try and include these parameters.

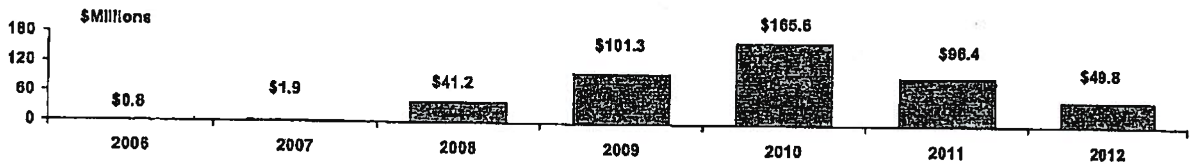
Risk Assessment, Major Risk Concerns

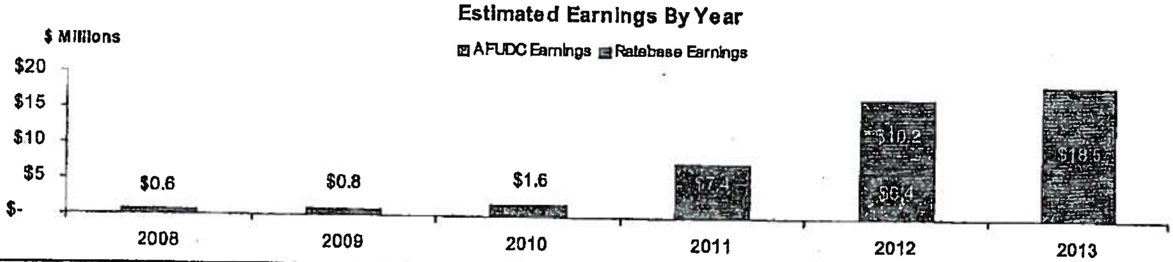
Clean Air Project
Merrimack Station

Risk Event	Risk Horizon	Potential Project Capital Cost Impact	Likelihood of Occurrence (%)	Expected Value Capital Cost Exposure	Mitigation Plan
Vendors unable to meet project design criteria resulting in non-conforming bids. Note: bids received with mercury criteria. Risk relates to remaining design specifications.	2008-9	$25 million	25%	$6.25 million	In the event this occurs, an acceptable outcome will be negotiated during the procurement process.
Inability to design appropriate plant integration plans resulting in MK1 bypass, boiler implosion and noise issues.	2008-9	$12.5 million	50%	$6.25 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.
Scope definition changes drastically during construction resulting in additional expenditures and/or potential schedule delays.	2008-12	$18.75 million	20%	$3.75 million	PSNH team will work closely with WGI & EPC contractors to minimize the impact.
Proposed design is inadequate and does not meet operability/reliability/ constructability requirements resulting in complete redesign.	2008-9	$12.5 million	30%	$3.75 million	PSNH contracted with experienced contract program manager in Scrubber installations. Additionally, NU personnel will be reviewing design specifications for reasonableness.

Clean Air Project

Cashflow and Earnings Projection





EPS	$.00	$.00	$.01	$.02	$.03	$.04

Assumptions:

- Base-case project costs are estimated at $457M
- Project expected to be in-service on June 30, 2012
- Assumes 9.81% ROE on 47.23% of Capital Structure
- Average Shares outstanding per 2009-2013 Forecast

Clean Air Project

Project Benefits are Accentuated by Advancing the In-Service Date to mid-2012

- Financial
  - Reduces AFUDC cost by $10 Million
  - Limits exposure to material or labor cost escalation for project elements not covered by firm price contracts
  - Generates real earnings one year sooner
- Environmental
  - Eliminates an additional 31,350 tons of SO_2
  - Eliminates an additional 229 pounds of Mercury
  - Reduces particulate emissions to less than 1% one year sooner
- Customer
  - Produces "early reduction mercury credits" that can be used for
    - Compliance in future years if operational issues with the scrubber arise
    - Conversion to fungible SO_2 allowances (estimated at 12,500 allowances)

FOR APPROVAL BY THE NORTHEAST UTILITIES RISK AND CAPITAL COMMITTEE

June 25, 2008

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE CLEAN AIR PROJECT

ISSUE:

The Northeast Utilities Risk and Capital Committee (RaCC) provides oversight and input for capital programs and projects exceeding $10 million. The PSNH Clean Air Project was brought to RaCC on May 30, 2007 for conceptual project review and initial funding approval, and for revised initial funding approval on September 24, 2007.

Consistent with the NU RaCC Charter, the PSNH Clean Air Project is being brought to the RaCC for review and recommendation for approval to the Chairman, President and CEO (CEO) of NU and Chairman of Public Service Company of New Hampshire.

RECOMMENDATION:

RECOMMEND CEO AND CHAIRMAN APPROVES THE PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE CLEAN AIR PROJECT CAPITAL FUNDING:

The RaCC recommends that the CEO and Chairman of PSNH approve the expenditure of $457 million of capital funding, inclusive of funds spent to date as provided for in the attached material.

ATTACHMENTS:

Presentation entitled "The Public Service Company of New Hampshire Clean Air Project".

RaCC resolution recommending CEO and Chairman approval of capital funding for the PSNH Clean Air Project.

RECOMMEND APPROVAL OF CAPITAL FUNDING FOR THE PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE CLEAN AIR PROJECT BY THE CEO OF NU AND THE CHAIRMAN OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE.

WHEREAS, Public Service Company of New Hampshire ("PSNH") management provided the Committee with a capital project approval proposal for the PSNH Clean Air Project and have requested $457 million of capital funding, inclusive of funds spent to date; and

WHEREAS, this Committee has reviewed said proposal;

NOW THEREFORE, BE IT

RESOLVED, that this Committee finds the following capital funding by Public Service Company of New Hampshire ("PSNH") of the PSNH Clean Air Project as described in the material submitted to this meeting and ordered filed with its records thereof acceptable.

Project	Total Cost	Year of Completion
PSNH Clean Air Project	$457 million, inclusive of funds spent to date	2012

RESOLVED, that this Committee recommends that the Chairman of the Board, President and Chief Executive Officer of Northeast Utilities and the Chairman of PSNH approve the capital funding by PSNH of the PSNH Clean Air Project, provided however that this Committee further recommends that a status update on the project be submitted to the Committee no less frequently than quarterly and the capital funding by PSNH set forth above shall not be exceeded without prior approval by the Committee.

APPROVAL OF CAPITAL FUNDING FOR THE PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE CLEAN AIR PROJECT BY THE CEO OF NU AND THE CHAIRMAN OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE.

Approved as recommended by the Risk and Capital Committee on June 25, 2008 as set forth above:

NORTHEAST UTILITIES

Date: 9/24/08

By: Charles W. Shivery
Charles W. Shivery
Chairman of the Board, President
And Chief Executive Officer

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Date: 9/24/08

By: Charles W. Shivery
Charles W. Shivery
Chairman

N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-6
Witness William H. Smagula
DO NOT REMOVE FROM FILE

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-01
Dated: 09/21/2012
Q-TECH-008

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

Question:
Re: Staff 2-2, page 18 of 50. Please provide the Brattle Group analysis referred to at the bottom of the page.

Response:
Brattle Group participated in the Connecticut Integrated Resource Plan. Attached is a supplemental analysis performed during 2008 in support of that effort.

EXHIBIT NO. 6
9/16/17
S. ROBIDAS

Documentation Report for Supplemental Analysis Requested by the CEAB via La Capra Associates, Inc.

August 1, 2008

Prepared by:

The Brattle Group

Connecticut Light & Power
The Northeast Utilities System

The United Illuminating Company

INTRODUCTION

On January 1, 2008, The Connecticut Light and Power Company (CL&P), The United Illuminated Company (UI) (together, "the Companies"), and *The Brattle Group*, an independent economic consulting firm, submitted a resource assessment and procurement plan ("Plan") to the Connecticut Energy Advisory Board (CEAB) pursuant to Section 51 of PA 07-242. On behalf of the CEAB, La Capra Associates (La Capra) requested that the Companies provide a supplemental analysis based on La Capra's specified assumptions. *The Brattle Group* implemented the requested analysis using the same modeling tools and other assumptions as those used in the Plan. This report describes the supplemental analysis.

Broadly, the supplemental analysis involved:

- Assuming the DSM-Focus resource solution presented in the Plan is implemented;
- Evaluating the implications of building a specified portfolio of new renewable generation that is sufficient to comply with all New England states' Renewable Portfolio Standards (RPS); and
- Evaluating the implications of state implementation plans that require every generating unit to control its rates of SOx and NOx emissions, as specified below, or retire.

This analysis was implemented by performing four additional simulations of the 2018 ISO-NE market ("cases"),[1] with each case building sequentially on the previous, and these cases are also described in further detail in the body of this report:

1. "Base Case" – a supplemental case based on the Current Trends Scenario and DSM-Focus Resource Solution market simulation in the Plan. This case serves as a benchmark to the Renewables Buildout Case.
2. "Renewables Buildout Case" – starting from the Base Case, enough new renewable generation is assumed to be online to meet all states' RPS requirements, and the amount of new gas-fired generation is correspondingly reduced.
3. "Emissions Controls and Retirements Case" – starting from the Renewables Buildout Case, all steam units control NOx and SOx emissions if the required capital expenditures can be recovered through expected future operating margins, or else they retire and get replaced by new gas-fired capacity.
4. "Emissions Controls and Retirements with Nuclear Build Case" – starting from the Emissions Controls and Retirements Case, the retired capacity is replaced by one new 1,200 MW nuclear unit, with any remaining capacity needs met by new gas-fired units.

[1] The construct of the supplemental analyses does not fit within the scenario/resource solution construct used in the Plan, so these additional simulations are referred to simply as cases.

CASE DESCRIPTIONS

This section describes the inputs for each of the four cases, and the cost and environmental implications for both Connecticut and the ISO as a whole. The last section summarizes the high-level findings based on these analyses, and Appendices A and B compare all case inputs and results, respectively. Appendix C contains the detailed metrics results for each case.

BASE CASE

The Base Case is based on the 2018 Current Trends scenario with DSM-Focus solution, as presented in the Plan. This case reflects moderate fuel prices and load growth, current construction costs, moderate-to-high CO_2 prices, and aggressive implementation of DSM in Connecticut. Due to time constraints, this single scenario/resource solution combination was selected by La Capra as a benchmark for the purposes of the supplemental analysis.

All Base Case parameters are identical to the 2018 Current Trends scenario with DSM-Focus solution, with the exception of:

- Unit-specific NOx and SOx emission rates for all steam oil and coal units were revised to reflect actual 2007 rates, where possible; and
- Other adjustments to unit outage schedules and gas availability for dual fuel units were made to ensure consistency across the supplemental cases.

Compared to the 2018 Current Trends scenario with DSM-Focus solution, these changes result in LMPs which are on average about $1 lower, and a 1% increase in generation dispatched in Connecticut.

RENEWABLES BUILDOUT CASE

The Renewables Buildout Case differs from the Base Case by (1) adding sufficient renewable capacity to satisfy all states' RPS requirements,[2] and (2) rebalancing capacity reserve margins by "unbuilding" generic gas new combined cycle (NCC) capacity.

[2] On July 2, 2008, Massachusetts increased its RPS requirement from 9% by 2018 to 13% by 2018, which is not included in this analysis.

The types, locations, and sizes of the new renewable units were provided by La Capra, and are summarized in Table 1 below. The Renewables Buildout Case reflects the assumption that there would be adequate high-quality sites available for developing these renewables as specified by La Capra.

Table 1: Type, Location, and Size of New or Retrofit Renewable Capacity

Resource Type	Zone	Nameplate Capacity (MW)	Effective Capacity* (MW)	Annual Energy (GWh)	Capacity Factor (%)
Hydro	CT	3	3	15	57%
	MA	1	1	2	35%
	ME	6	6	26	50%
	NH	5	5	20	52%
	RI	7	7	35	56%
	VT	12	12	42	41%
Hydro Total		33	33	141	
Import Wind	NB	500	100	1,489	34%
	NY	249	50	675	31%
	QC	506	101	1,507	34%
Import Wind Total		1,254	251	3,671	
Landfill Gas	CT	10	10	72	80%
	MA	17	17	119	80%
	ME	4	4	29	80%
	NH	8	8	59	80%
	RI	3	3	20	80%
	VT	0	0	2	80%
Landfill Gas Total		43	43	301	
Wind	MA	172	34	503	33%
	ME	402	80	1,213	34%
	NH	292	58	931	36%
	VT	415	83	1,270	35%
Wind Total		1,282	256	3,917	
Biomass Retrofit**	MA	5	5	37	85%
	ME	100	100	745	85%
	NH	26	26	192	85%
	VT	22	22	163	85%
Biomass Retrofit Total		153	153	1,137	
Biomass Repower***	MA	41	41	302	85%
	ME	100	100	745	85%
	NH	36	36	266	85%
	VT	35	35	261	85%
Biomass Repower Total		211	211	1,573	
Grand Total		2,976	947	10,741	

Source: La Capra Associates.
*Equals nameplate capacity, with wind derated to 20%.
**Biomass Retrofits are biomass facilities which retrofit with emissions controls to meet CT RPS requirements.
***Biomass Repower are existing or retired facilities which repower to burn biomass.

The total nameplate capacity of the new renewable units is 2,976 MW, composed mostly of wind and some biomass. Roughly half of the wind is built in Maine and Vermont, and roughly half is assumed to be imported from New York, New Brunswick, and Hydro-Quebec. New York wind imports are assumed to be delivered to Connecticut, and Canadian wind imports are assumed to be distributed evenly among Connecticut, New Hampshire, and Boston via new transmission. Total nameplate imported wind capacity distributed to Connecticut is 584 MW. Total retrofit or repowered biomass capacity is 364 MW, also mostly located in Maine. Only a very small amount of renewables is constructed in Connecticut (13 MW).

The new renewable units contribute 947 MW to meeting resource adequacy needs, based on a 20% credit for intermittent wind resources. This eliminates the need to build 900 MW of generic NCC capacity that were included in the Base Case in Maine (300 MW) and West/Central Massachusetts (600 MW).

Some enhancements to the transmission system are required to accommodate the new wind imports. A new DC transmission line is assumed to connect wind imports from New Brunswick and Hydro-Quebec to load centers in Boston, Norwalk, and New Hampshire. The Companies and *The Brattle Group* did not independently evaluate the feasibility or cost of building this required transmission. It is assumed that the cost of the new transmission is $2.5 million per nameplate MW of new wind capacity, or a total of $2.5 billion in overnight cost and a $304 million annual capital carrying charge, as shown in Table 2. Connecticut's share of the total annual capital carrying charge is assumed to be one-third (based on the State's share of the wind generation purchased), or $101 million.[3] New wind energy imported from New York is added to existing imports from New York, and the New York-New England interface is assumed to be upgraded as necessary to accommodate the additional flow of energy. Any costs associated with upgrading the New York-New England interface are not included in this analysis.

Table 2: Capital Cost of New Transmission for Imported Wind

	Units	Value
Wind Imports from NB and HQ (Nameplate)	*(MW)*	1,006
Cost of New Transmission	*($Mil/MW)*	$2.5
Total Overnight Cost of Transmission	*($Mil)*	$2,515
Connecticut Share of Overnight Cost of Transmission (1/3)	*($Mil)*	$838
Annual Capital Carrying Charge Rate	*(%)*	12.1%
Total Annual Capital Carrying Charge	***($Mil)***	**$304**
Connecticut Share of Annual Capital Carrying Charge (1/3)	***($Mil)***	**$101**

[3] This cost allocation is illustrative and does not necessarily reflect how costs would actually be allocated for new transmission that is built for economic and RPS compliance reasons.

The total capital cost of new renewables and enabling transmission is summarized in Table 3 below. Wind, biomass, and landfill unit capital costs are based on generic parameters specified in Table E.5 of the Plan. The $3,200/kW overnight capital cost of hydro units was provided by La Capra, with an assumed 11.3 percent annual capital carrying charge.

Table 3: Capital Cost of New Renewable Generation for the ISO and Connecticut

	Units	Unit Type				New Transmission	Total
		Wind*	Biomass	Hydro	Landfill		
Total Nameplate Capacity	*(MW)*	2,536	364	33	43		
Overnight Cost	*($/kW)*	$2,000	$3,142	$3,200	$2,356	$2,500	$13,198
Total Overnight Cost	*($Mil)*	$5,073	$1,144	$106	$101	$2,515	$8,938
Annual Capital Carrying Charge Rate	*(%)*	11.4%	12.1%	11.3%	11.6%	12.1%	
Total Annual Capital Carrying Charge	*($Mil)*	$578	$138	$12	$12	$304	$1,045
Connecticut Nameplate Capacity	*(MW)*	584	0	3	10		
Connecticut Share of Total Overnight Cost	*($Mil)*	$1,168	$0	$10	$24	$838	$2,040
Connecticut Share of Annual Capital Carrying Charge	*($Mil)*	$133	$0	$1	$3	$101	$238

*Includes imported wind.

In the simulation of the Renewables Buildout Case, the resulting costs and emissions differ from those in the Base Case in the following ways:

Costs

- ISO total going-forward resource cost: decreases by $222 million relative to the Base Case, in which new renewable generation is assumed not to be viable in significant quantities and RPS is satisfied primarily through Alternative Compliance Payments (ACPs). Avoiding Renewable Energy Credit (REC)/ACP payments and fossil generation costs each save more than $600 million, which more than offsets the approximately $1.13 billion of annualized capital plus operating costs of new renewables and associated transmission;[4]
- CT total going-forward resource cost: increases by $27 million, primarily due to the capital cost of new wind imports and new transmission, which are only partially offset by fuel and REC/ACP savings;
- CT customer cost in market regime: decreases by $11 million, or 0.03 cents per kWh, relative to the Base Case, in which new renewable generation is assumed to be insufficient and REC/ACP prices are almost twice as high; and
- CT customer cost in cost-of-service regime: increases by $27 million, or 0.08 cents per kWh.

[4] All costs in this report are expressed in 2008 dollars.

Emissions

- ISO-wide emissions: annual NOx emissions decrease by 1,027 tons (-5%), SOx decreases by 3,061 tons (-3%), and CO_2 decreases by 4,679,961 tons (-9%);
- CT emissions: annual NOx emissions decrease by 106 tons (-3%), SOx decreases by 174 tons (-3%), CO_2 decreases by 306,666 tons (-3%); and
- CT monitored NOx during top 10 days: increases 3% due to changes in unit commitment and dispatch.

Other Observations

- Prices: average LMPs decrease by $1 in Connecticut, $1-2 in the South, and $2-3 in the North;
- Congestion: north-to-south congestion increases on the North/South interface due to the increase in renewable generation in the North; and
- Generation: Renewable generation displaces fossil generation, primarily from gas CCs;
- Winter gas use (Jan-Feb): decreases by 19% in ISO-NE and 5% in Connecticut due to new renewable generation reducing the need for new gas-fired generation.

The assumed renewables achieve larger percentage reductions in CO_2 reductions than SOx and NOx reductions. Total ISO-wide CO_2 emissions are reduced by 4.7 million tons, or about 9 percent. On a per-ton basis, the implied cost of achieving this level of CO_2 abatement is about $104 per ton of CO_2. This represents the change in the ISO-wide total going-forward resource cost in this case (*without* including CO_2 allowance price savings), compared to the ISO-wide total going-forward resource cost in the Base Case (*without* RPS costs), divided by the tons of CO_2 abated.

Based on the assumptions used in this case, New England-wide renewables cost $423 million (including fuel savings), or about $40 per MWh of new renewable generation. This represents the capital and operating cost of the renewables and associated transmission minus the costs of avoided fossil generation and capacity. It is calculated by comparing the ISO-wide total going-forward resource cost to the Base Case (*without* RPS costs), divided by the total MWh of new renewable generation. The Connecticut-only resource cost of RPS is $275 million, and the market-based customer cost is $237 million. (Both of these figures include the $101 million allocated capital cost of new transmission for wind imports shown previously in Tables 2 and 3.)

EMISSIONS CONTROLS AND RETIREMENTS CASE

The Emissions Controls and Retirements Case adopts the assumptions of the Renewables Buildout Case and also enforces unit-level SOx and NOx emission rate requirements. This case represents a market in which (1) enough investment in renewable generation takes place to satisfy ISO-wide RPS, and (2) each unit that exceeds the required SOx or NOx emission rate target faces a decision to either invest in any required emission control equipment or retire.

SOx and NOx emission rate limits were provided by La Capra and are shown in Table 4. The SOx rate requirement is 0.30 lbs/MMBtu by 2011 and 0.15 lbs/MMBtu by 2018. The NOx rate requirement is 0.12 lbs/MMBtu by 2011 and 0.08 lbs/MMBtu. All units, New England-wide, that exceed one or both of these targets must either invest in scrubbers and/or selective catalytic reduction (SCR) control equipment or retire.

Table 4: SOx and NOx Emission Rate Requirements

SOx Target Rate *(Lbs/MMBtu)*	NOx Target Rate *(Lbs/MMBtu)*
0.30 by 2011 0.15 by 2018	0.12 by 2011 0.08 by 2018

Source: La Capra Associates.

These emission rate requirements are presumably consistent with the EPA Clean Air Interstate Rule (CAIR),[5] which required state implementation of SOx and NOx emission caps. However, CAIR was vacated on July 11, 2008, so this case would assume CAIR is replaced with similar legislation to cap SOx and NOx emissions in the region, or else all New England states simply adopt unit-level emission rate requirements.

In the January 1, 2008 Plan, generic SOx and NOx emission rates based on fuel type were used for all generating units, with the exception of the "Sooty Six."[6] In this analysis, these generic rates are replaced with actual unit-specific emission rates for steam oil and coal units identified as the units most at risk for exceeding the specified SOx and NOx emission rate targets. SOx and NOx emission rates for these units were revised where possible to reflect actual 2007

[5] See http://www.epa.gov/cair/ for more information.

[6] The "Sooty Six" include Bridgeport Harbor 2 & 3, Devon 7 & 8 (retired), Middletown 2-4, Montville 5 & 6, New Haven Harbor, and Norwalk Harbor 1 & 2. See Appendix G of the Plan for a description of the emission rates used.

emission rates. This is done to more accurately simulate their unit-level invest-or-retire decision. The actual 2007 emission rates are average annual rates from EPA Continuous Emission Monitoring System (CEMS) data. Where CEMS data are missing for these steam oil and coal units, generic emission rates are applied.

The 2007 CEMS data indicate that the oil/gas dual fuel units Middletown 2 & 3, Montville 5, Brayton Point 4, Mystic 7, Newington 1, and West Springfield 3 ran almost exclusively on natural gas, presumably due to currently high oil prices. Data for these units indicate the capability to switch entirely to natural gas, and these units are assumed to run only on natural gas in all four cases. For consistency and more reliable comparisons, any revised emission rates are also used in all four cases in this supplemental analysis. The steam oil and coal emission rates used are shown in Table 6 below.

The owner of a unit that exceeds one or both of the emission rate limits is assumed to invest in emission control equipment if the expected market net revenues will be sufficient to cover the capital cost of the control equipment. To simulate this decision-making process and determine which units will retire and which will invest in control equipment, a retirement analysis is done on each steam oil and coal unit in the ISO. This retirement analysis compares the expected energy margins and capacity revenues from all scenarios in the Plan to the capital cost of control equipment provided by La Capra plus fixed O&M (FOM) expenses.[7]

For each steam oil and coal unit, the expected energy margins are calculated as the annuitized stream of the average energy margin earned in all scenarios (Current Trends, Strict Climate Policy, High Fuel/Growth, and Low Stress) for the life of the control equipment investment. In calculating the average expected energy margin, the Current Trends is weighted at 50 percent and all other scenarios are weighted at 16.67 percent. Expected capacity revenues are calculated in a similar fashion, using an annuitized stream of capacity prices from all scenarios for the life

[7] We conducted an initial analysis of retirement candidates based on the revenues estimated across all scenarios in the original Plan. Then we performed an initial energy market simulation with the identified retirement candidates replaced by new CCs, but only in the Renewables Buildout Case (Current Trends scenario) and not in any of the other scenarios corresponding to the original Plan. The observed increase in capacity prices (driven by decreased energy prices) was considered in finalizing the retirement decisions, resulting in not all of the retirement candidates actually retiring.

of the control equipment investment. The overnight capital cost of scrubbers and SCRs is provided by La Capra, as shown in Table 5. This cost is also annuitized based on an assumed equipment life.

Table 5: Overnight Capital Cost SOx and NOx Control Equipment

Control Equipment Type	Capital Cost *($/kW)*
SCR - BOILER	
Coal	256
Oil	114
Distillate Oil	114
Gas	87
SCR - CT	
Oil	82
Gas	82
SCRUBBER	
Large Boiler (600 MW)	242
Small Boiler (200-300 MW)	471

Source: La Capra Associates.

The following formula is used in determining whether or not a given steam oil or coal unit will invest in control equipment by 2018. The formula is evaluated using 5, 10, and 15 year equipment life assumptions. Capital charge rates are also shown below the formula, and are consistent with those used in evaluating technology types in the Plan:

[1] Is $(\text{Expected Energy Margin})_{ij} + (\text{Expected Capacity Revenue})_{ij} - \text{Annual FOM}_i$
$>$
$(\text{Control Equipment Cost})_{ij}$?

Where,

i = unit
j = annuitized using 5, 10, or 15 year assumption on equipment life

33% = 5-year capital charge rate
19% = 10-year capital charge rate
15% = 15-year capital charge rate[8]

[8] These 5, 10, and 15 year capital charge rates are approximately equal to 3, 5, and 7 year simple paybacks.

Once formula [1] above is evaluated for each unit, the following rules and assumptions are used to determine which units retire and which invest in the required control equipment:

- Canal 2 (553 MW) and New Haven Harbor (461 MW) have dual fuel capability and are assumed to develop their gas supply and burn gas only;
- Several small steam units – Somerset (10 MW), Holyoke/Cabot 6 (9 MW), Holyoke/Cabot 8 (9 MW), and Kendall Steam 1-3 (60 MW) – are assumed not to invest due to economies of scale in control equipment costs;
- All other coal units will invest due to higher energy margins when fewer allowances are purchased with lower overall emissions;
- For all remaining units for which formula [1] is true with a 10-year equipment life, the unit will invest;
- For all remaining units for which formula [1] is false with a 10-year equipment life but true with a 15-year equipment life, there is a 50% chance the unit will invest (to reflect this in the simulation, the capacity of these units is derated by 50%);
- For all remaining units for which formula [1] is false with a 15-year equipment life, the unit will retire; and
- The resulting quantity of retirements changes the economics of the remaining units such that two units, Brayton Point 4 (435 MW) and Salem Harbor 4 (380 MW), would be more likely to invest than retire (these findings were based on the iterative results described in footnote 7).

The results of the retirement analysis are presented in Table 6. Total retirements are 2,655 MW, which includes 2,645 MW steam oil capacity and 10 MW coal capacity. Steam oil retirements occur mostly in Connecticut, and also in Maine and Massachusetts. Total capacity investing in control equipment is 3,852 MW, including 1,059 MW of steam oil capacity in Connecticut and Massachusetts and 2,793 MW of coal capacity. 2,070 MW of capacity does not require any new control equipment due to emission rates that presently meet the specified SOx and NOx rates. The total overnight capital cost of investing in scrubbers and SCRs is about $1.85 billion, or $356 million in annual capital carrying charges.

Retired capacity is replaced by 2,400 MW of generic natural gas new combined-cycle (NCC) capacity. This includes 900 MW in Connecticut, 600 MW in Maine, and 900 MW in Massachusetts.

Table 6: Steam Oil and Coal Unit Scrubber and SCR Investment Decisions

Unit Name		Notes	Unit Type	Summer Capacity (MW)	State	NOx Rate (Lbs/MMBtu)	SOx Rate (Lbs/MMBtu)	Final Decision	Retired (MW)	Maximum tolerable cost of alternative gas conversion w/10 year life ($/kW)	Maximum tolerable cost of alternative gas conversion w/15 year life ($/kW)
CANAL 1			Oil	254	MA	0.04	0.54	Retire	254	112	159
CANAL 2	[1]	Develop gas supply and burn gas only	Oil	553	MA	0.08	0.00	Status Quo	0		
CLEARY 8			Oil	26	MA	0.26	0.81	Retire	26	60	96
HOLYOKE 6/CABOT 6	[2]		Oil	9	MA	[redacted]	[redacted]	Retire	9		
HOLYOKE 8/CABOT 8	[2]		Oil	9	MA	[redacted]	[redacted]	Retire	9		
KENDALL STEAM 1 2 3	[2]		Oil	60	MA	[redacted]	[redacted]	Retire	60		
MIDDLETOWN 3	[3]	Burn gas only	Oil	236	CT	0.21	0.01	Invest	0	172	240
MIDDLETOWN 4			Oil	400	CT	0.20	0.26	Retire	400	82	123
MONTVILLE 5	[3]	Burn gas only	Oil	81	CT	0.09	0.01	Invest	0	192	266
YARMOUTH 2			Oil	52	ME	0.20	0.80	Retire	52	53	95
BRAYTON PT 4	[3]	Burn gas only	Oil	435	MA	0.09	0.00	Invest	0	86	129
BRIDGEPORT HARBOR 2			Oil	130	CT	0.30	0.28	Retire	130	8	24
MIDDLETOWN 2	[3]	Burn gas only	Oil	117	CT	0.09	0.01	Invest	0	194	269
MONTVILLE 6			Oil	407	CT	0.19	0.25	Retire	407	1	18
MYSTIC 7	[3]	Burn gas only	Oil	555	MA	0.06	0.00	Status Quo	0		
NEW HAVEN HARBOR	[1]	Develop gas supply and burn gas only	Oil	461	CT	0.08	0.00	Status Quo	0		
NEWINGTON 1	[3]	Burn gas only	Oil	400	NH	0.05	0.02	Status Quo	0		
NORWALK HARBOR 1			Oil	162	CT	0.15	0.29	Retire	162	10	24
NORWALK HARBOR 2			Oil	168	CT	0.16	0.29	Retire	168	-4	7
SALEM HARBOR 4			Oil	380	MA	0.21	0.49	Retire 50 %	190	186	254
WEST SPRINGFIELD 3	[3]	Burn gas only	Oil	101	MA	0.06	0.00	Status Quo	0		
YARMOUTH 1			Oil	52	ME	0.20	0.80	Retire	52	57	99
YARMOUTH 3			Oil	117	ME	0.20	0.80	Retire	117	85	127
YARMOUTH 4			Oil	609	ME	0.20	0.80	Retire	609	76	116
AES THAMES	[4]		Coal	181	CT	0.07	0.24	Invest	0	457	594
BRAYTON PT 1	[4]		Coal	243	MA	0.09	0.82	Invest	0	762	982
BRAYTON PT 2	[4]		Coal	222	MA	0.23	0.80	Invest	0	806	1,045
BRAYTON PT 3	[4]		Coal	612	MA	0.10	0.78	Invest	0	900	1,173
BRIDGEPORT HARBOR 3	[4]		Coal	372	CT	0.13	0.31	Invest	0	1,168	1,496
MEAD	[4]		Coal	75	ME	0.30	1.20	Invest	0	788	1,023
MERRIMACK 1	[4]		Coal	113	NH	0.18	2.10	Invest	0	647	842
MERRIMACK 2	[4]		Coal	320	NH	0.18	1.97	Invest	0	828	1,092
MT TOM	[4]		Coal	145	MA	0.12	0.85	Invest	0	609	773
SALEM HARBOR 1	[4]		Coal	82	MA	0.14	0.65	Invest	0	691	891
SALEM HARBOR 2	[4]		Coal	80	MA	0.13	0.63	Invest	0	673	877
SALEM HARBOR 3	[4]		Coal	149	MA	0.16	0.63	Invest	0	627	825
SCHILLER 4	[4]		Coal	48	NH	0.18	0.98	Invest	0	618	798
SCHILLER 6	[4]		Coal	47	NH	0.21	1.01	Invest	0	506	656
SOMERSET	[4]		Coal	10	ME	[redacted]	[redacted]	Retire	10		
SOMERSET 6	[4]		Coal	105	MA	0.12	0.67	Invest	0	566	730
Retire (MW)									2,655		
Invest (MW)									3,852		
Status Quo (MW)									2,070		
Connecticut Only: Retire (MW)									1,267		
Connecticut Only: Invest (MW)									987		
Connecticut Only: Status Quo (MW)									461		

Notes:
[1]: We assumed that Canal 2 and New Haven Harbor burn gas and hence meet the SOx and NOx emissions rates. The emission rates shown here for these 2 units are not CEMS emissions rates.
[2]: Holyoke 6, Holyoke 8 and Kendall Steam 1 2 3 are assumed to exceed the NOx and SOx limits and hence we decide to retire them.
[3]: We assumed that Middletown 2 and 3, Montville 5, Brayton Pt 4, Mystic 7, Newington 1 and West Springfield 3, would just burn gas because they can, and doing so would eliminate SOx and reduce NOx.
Hence their emission rates reflect generation weighted CEMS emissions rates when SOx emissions are less than 0.05 lbs/MMBtu
Of the above dual fueled units Canal 2 ,New Haven Harbor, Mystic 7, Newington 1 and West Springfield 3 met the NOx and SOx emission target rates.
Brayton Point 4, Middletown 2 and 3, and Montville 5 exceed the NOx emission target rate but not the SOx emission target rates. Hence, capital cost for these units include only the cost of the SCR.
[4]: We assumed that coal units (except Somerset) would invest because the energy margins will be higher when fewer allowances are purchased with lower emissions.

The costs and emissions in the Emissions Controls and Retirements Case differ from those in the Renewables Buildout Case in the following ways:

Costs

- ISO total going-forward resource cost: increases by $491 million, primarily because of the cost of installing emission controls, which are only partially offset by a reduction in allowance costs;
- CT total going-forward resource cost: increases by $96 million, due to the costs of installing emission controls and the cost of replacing retired capacity;

- CT customer cost in market regime: increases by \$50 million, or 0.15 cents per kWh due to increased capacity payments that more than offset energy price decreases caused by NCC generation; and
- CT customer cost in cost-of-service regime: increases by \$96 million, or 0.28 cents per kWh.

Emissions

- ISO-wide emissions: NOx decreases 7,047 tons (-37%), SOx decreases 74,373 tons (-81%), and CO_2 decreases 711,020 tons (-2%), with most of the emissions change due to coal units investing;
- CT emissions: NOx decreases by 940 tons (-26%), SOx decreases by 2,191 tons (-43%), and CO_2 increases by 1,190,353 tons (+12%). 70% of the SOx abatement is from adding scrubbers to the two coal units in Connecticut, and the rest is equally due to New Haven Harbor's assumed oil-to-gas conversion and the retirement of five other oil units. The NOx abatement sources are similar, but with the oil-to-gas conversions and oil retirements playing a slightly larger proportional role; and
- CT monitored NOx during top 10 peak days: 61% reduction in Connecticut; other states decrease by 14–70%.

Other Observations

- Prices: LMPs decrease by \$3 in Connecticut, \$4 in Maine and Boston, \$2 in Rhode Island and Southeastern Massachusetts, and \$3 in the rest of zones due to the addition of 2,400 MW NCCs;
- Congestion: congestion on the North/South interface increases due to NCCs replacing some steam oil retirements in the North;
- Generation: most NCCs run at an intermediate capacity factor of 30-60% and existing CCs run less than in the prior case;
- Winter gas use (Jan-Feb): increases by 6% in ISO-NE and 37% in Connecticut due to new gas-fired generation in Connecticut, Maine, and Massachusetts replacing retired steam oil capacity;
- Coal units: on net, coal units investing in emission controls run less due to the addition of NCCs; those that previously had high SOx rates are running 2-10% more, while others run 2-12% less (an effect of reducing emissions rates only to target levels); and
- Steam oil units that invest in SCRs and scrubbers and steam oil units already running on gas: 1-2% reduction in capacity factors due to the addition of NCCs.

Importantly, almost all of the SOx and NOx emissions reductions are due to investments rather than retirements, primarily due to the low Base Case capacity factors and annual emissions of the units that retire in the Emissions Controls and Retirements Case. Investments in scrubbers and SCRs for coal units have the largest impact on SOx and NOx emissions, respectively. At the ISO level, controlling emissions from coal plants reduces SOx emissions by 78 percent and NOx emissions by 31 percent. In contrast, steam oil units switching to natural gas or investing in control equipment results in only a one percent reduction in SOx emissions and a three percent reduction in NOx emissions in ISO-NE. Table 7 illustrates the SOx and NOx emissions reductions for each oil and coal unit in Connecticut. Units that invest in emissions controls or that convert to natural gas operation reduce NOx emissions by 1,119 tons and SOx emissions by 2,084 tons, mostly attributable to coal units that invest in SCR and scrubbers, respectively. In contrast, units that retire reduce NOx emissions by only 193 tons and SOx emissions by 292 tons.

Table 7: Steam Oil and Coal Unit NOx and SOx Reductions in Connecticut

Unit Name	Notes	Unit Type	Decision in Emissions Controls and Retirements Case	Summer Capacity *(MW)*	Generation in Base Case *(GWh)*	Capacity Factor in Base Case *(%)*	Total NOx Emissions in Base Case *(Tons)*	Total SOx Emissions in Base Case *(Tons)*	Total NOx Emissions in Emissions Controls and Retirements Case *(Tons)*	Total SOx Emissions in Emissions Controls and Retirements Case *(Tons)*	Reduction in Total NOx Emissions *(Tons)*	Reduction in Total SOx Emissions *(Tons)*
MONTVILLE 5	Burn gas only	Oil	Invest	81	15	2%	8	1	4	0	4	0
MIDDLETOWN 3	Burn gas only	Oil	Invest	236	52	2%	54	2	14	1	40	1
MIDDLETOWN 2	Burn gas only	Oil	Invest	117	16	2%	9	1	5	1	4	0
NORWALK HARBOR 2		Oil	Retire	168	58	4%	43	80	0	0	43	80
NORWALK HARBOR 1		Oil	Retire	162	69	5%	49	95	0	0	49	95
MONTVILLE 6		Oil	Retire	407	19	1%	23	31	0	0	23	31
MIDDLETOWN 4		Oil	Retire	400	27	1%	37	48	0	0	37	48
BRIDGEPORT HARBOR 2		Oil	Retire	130	28	2%	42	38	0	0	42	38
NEW HAVEN HARBOR	Develop gas supply and burn gas only	Oil	Status Quo	461	434	11%	301	488	11	1	290	488
BRIDGEPORT HARBOR 3		Coal	Invest	372	2,762	85%	1,764	2,795	1,044	1,957	720	838
AES THAMES		Coal	Invest	181	1,272	80%	514	1,680	452	923	62	757
Total Oil Units that Invest or Develop Gas Supply				895	516		372	492	34	3	337	489
Total Coal Units that Invest				553	4,034		2,278	4,475	1,495	2,880	782	1,595
Total Oil Units that Retire				1,267	200		193	293	0	0	193	292
Total Units that Invest or Develop Gas Supply				1,448	4,551		2,649	4,967	1,530	2,883	1,119	2,084

The relative SOx and NOx abatement costs are shown at the unit level in Tables 8 and 9, respectively. Tables 8 and 9 show each unit's scrubber and SCR capital expenditures, minus their allowance price savings from lower emissions, plus additional variable O&M (VOM) costs of the new equipment. The equipment capital costs are based on data provided by La Capra as shown previously in Table 5. The change in total emissions is based on the reduction in emission rates multiplied by the amount of generation in the Base Case.[9] It should be noted that the net abatement cost for each unit, shown in the rightmost column, is highly dependent on the La Capra assumption of VOM and other costs.

[9] Calculating abatement costs based on a constant level of generation avoids counting the partially-offsetting increases in emissions associated with increased generation by the cleaned-up unit. Including such increases would imply less abatement than actually achieved, since the cleaned-up unit's additional generation displaces generation and associated emissions from other units.

Table 8: Additional Cost of SOx Abatement, by Unit

Unit Name	Unit Type	Note on Fuel Use	Heat Rate *(Btu/kWh)*	Base Case Generation *(MWh)*	SOx Rate in the Base Case *(Lbs/MMBtu)*	SOx Rate in the Emissions Controls and Retirements Case *(Lbs/MMBtu)*	Change in Total SOx Emissions *(Tons)*	Allowance Price Savings *($)*	Increase in VOM due to SOx Control *($)*	Capital Carrying Cost of Scrubber *($/kW-Yr)*	Summer Capacity *(kW)*	Total Capital Carrying Cost of Scrubber *($)*	Total Cost Increase due to SOx Control *($)*	Net Cost of Abatement (Cost Increase net of Allowance Price Savings) *($/Ton)*
MIDDLETOWN 3	Oil	Burn gas only	10,000	31,519	0.01	0.01	0	0	0		[illegible]			
MONTVILLE 5	Oil	Burn gas only	[illegible]	24,908	0.01	0.01	0	0	0		[illegible]			
BRAYTON PT 4	Oil	Burn gas only	10,913	81,982	0.00	0.00	0	0	0		435,000			
MIDDLETOWN 2	Oil	Burn gas only	12,026	15,959	0.01	0.01	0	0	0		117,000			
SALEM HARBOR 4	Oil		12,000	30,291	0.32	0.02	-142	[illegible]	[illegible]	47	150,000	[illegible]	3,019,718	[illegible]
AES THAMES	Coal		11,000	1,272,492	0.24	0.01	-1,596	1,739,920	1,072,313	91	181,000	16,382,875	17,455,189	9,848
BRAYTON PT 1	Coal		9,484	1,700,947	0.82	0.04	-6,283	6,851,199	4,322,396	91	243,000	21,994,689	26,317,085	3,083
BRAYTON PT 2	Coal		9,484	1,724,816	0.80	0.04	-6,216	6,777,895	4,177,219	91	222,000	20,093,913	24,271,132	2,814
BRAYTON PT 3	Coal		8,849	4,640,661	0.78	0.04	-15,215	16,589,721	10,224,231	47	612,000	28,488,359	38,712,610	1,454
BRIDGEPORT HARBOR 3	Coal		9,640	2,761,781	0.21	0.01	-2,656	2,895,717	1,784,631	47	372,000	17,316,453	19,101,085	6,102
MEAD	Coal		9,000	579,779	1.20	0.06	-2,974	3,243,073	1,998,707	91	75,000	6,788,484	8,787,191	1,864
MERRIMACK 1	Coal		10,193	701,028	2.10	0.11	-7,128	7,771,896	4,789,822	91	112,500	10,182,726	14,972,549	1,010
MERRIMACK 2	Coal		10,193	2,484,555	1.97	0.10	-23,698	25,839,694	15,925,013	47	320,000	14,895,874	30,820,887	210
MT TOM	Coal		10,523	1,130,940	0.85	0.04	-4,805	5,239,343	3,228,947	91	145,000	13,124,403	16,353,350	2,313
SALEM HARBOR 1	Coal		10,177	628,100	0.65	0.03	-1,974	2,151,950	1,326,248	91	82,000	7,422,076	8,748,324	3,142
SALEM HARBOR 2	Coal		10,400	617,632	0.63	0.03	-1,922	2,095,918	1,291,715	91	80,000	7,241,050	8,532,765	3,349
SALEM HARBOR 3	Coal		10,500	1,127,003	0.63	0.03	-3,541	3,861,227	2,379,675	91	149,000	13,486,455	15,866,131	3,390
SCHILLER 4	Coal		10,641	369,230	0.98	0.05	-1,829	1,994,331	1,229,046	91	47,500	4,299,373	5,528,419	1,932
SCHILLER 6	Coal		11,226	332,304	1.01	0.05	-1,789	1,950,842	1,202,304	91	47,000	4,254,117	5,456,421	1,959
SOMERSET 6	Coal		10,907	802,624	0.67	0.03	-2,786	3,037,824	1,872,212	91	105,000	9,503,878	11,376,090	2,993

Source: Capital cost and VOM assumptions are provided by La Capra Associates. The net cost of abatement is dependent on the assumed $672/ton increase in VOM.

Table 9: Additional Cost of NOx Abatement, by Unit

Unit Name	Unit Type	Note on Fuel Use	Heat Rate *(Btu/kWh)*	Base Case Generation *(MWh)*	NOx Rate in the Base Case *(Lbs/MMBtu)*	NOx Rate in the Emissions Controls and Retirements Case *(Lbs/MMBtu)*	Change in Total NOx Emissions *(Tons)*	Allowance Price Savings *($)*	Increase in VOM due to NOx Control *($)*	Capital Carrying Cost of SCR *($/kW-Yr)*	Summer Capacity *(kW)*	Total Capital Carrying Cost of SCR *($)*	Total Cost Increase due to NOx Control *($)*	Net Cost of Abatement (Cost Increase net of Allowance Price Savings) *($/Ton)*
MIDDLETOWN 3	Oil	Burn gas only	10,000	[illegible]	0.21	0.05	-40	[illegible]	81,165	22	[illegible]	[illegible]	[illegible]	[illegible]
MONTVILLE 5	Oil	Burn gas only	[illegible]	24,908	0.09	0.02	[illegible]	[illegible]	12,016	22	81,000	[illegible]	[illegible]	[illegible]
BRAYTON PT 4	Oil	Burn gas only	10,913	81,982	0.09	0.02	[illegible]	84,895	[illegible]	22	435,000	[illegible]	[illegible]	[illegible]
MIDDLETOWN 2	Oil	Burn gas only	12,026	15,959	0.09	0.02	[illegible]	[illegible]	13,805	22	117,000	[illegible]	[illegible]	[illegible]
SALEM HARBOR 4	Oil		12,000	30,291	0.21	0.05	[illegible]	[illegible]	[illegible]	[illegible]	190,000	[illegible]	[illegible]	15,616
AES THAMES	Coal		11,000	1,272,492	0.07	0.07	0	0	0		181,000			
BRAYTON PT 1	Coal		9,484	1,700,947	0.09	0.02	-574	1,592,424	1,158,071	49	243,000	11,939,974	13,098,045	20,042
BRAYTON PT 2	Coal		9,484	1,724,816	0.23	0.06	-1,410	3,910,161	2,843,617	49	222,000	10,908,124	13,751,741	6,982
BRAYTON PT 3	Coal		8,849	4,640,661	0.10	0.02	-1,489	4,130,578	3,003,912	49	612,000	30,071,045	33,074,957	19,437
BRIDGEPORT HARBOR 3	Coal		9,640	2,761,781	0.13	0.03	-1,323	3,669,378	2,668,510	49	372,000	18,278,479	20,946,989	13,061
MEAD	Coal		9,000	579,779	0.30	0.08	-587	1,628,308	1,184,167	49	75,000	3,685,177	4,869,344	5,521
MERRIMACK 1	Coal		10,193	701,028	0.18	0.04	-478	1,326,740	964,835	49	112,500	5,527,766	6,492,621	10,800
MERRIMACK 2	Coal		10,193	2,484,555	0.18	0.04	-1,677	4,652,128	3,383,303	49	320,000	15,723,422	19,106,626	8,618
MT TOM	Coal		10,523	1,130,940	0.12	0.03	-517	1,434,739	1,043,396	49	145,000	7,124,676	8,168,072	13,018
SALEM HARBOR 1	Coal		10,177	628,100	0.14	0.04	-340	943,498	686,148	49	82,000	4,029,137	4,715,275	11,059
SALEM HARBOR 2	Coal		10,400	617,632	0.13	0.03	-322	893,316	649,653	49	80,000	3,930,856	4,580,509	11,449
SALEM HARBOR 3	Coal		10,500	1,127,003	0.16	0.04	-689	1,910,365	1,389,289	49	149,000	7,321,219	8,710,508	9,874
SCHILLER 4	Coal		10,641	369,230	0.18	0.05	-269	747,486	543,600	49	47,500	2,333,946	2,877,545	7,904
SCHILLER 6	Coal		11,226	332,304	0.21	0.05	-298	827,042	601,456	49	47,000	2,309,378	2,910,834	6,989
SOMERSET 6	Coal		10,907	802,624	0.12	0.03	-401	1,110,932	807,912	49	105,000	5,159,248	5,967,159	12,125

Source: Capital cost and VOM assumptions are provided by La Capra Associates. The net cost of abatement is dependent on the assumed $2,017/ton increase in VOM.

EMISSIONS CONTROLS AND RETIREMENTS WITH NUCLEAR BUILD CASE

The Emissions Controls and Retirements with Nuclear Build Case changes the assumptions of the Emissions Controls and Retirements Case by adding a 1,200 MW new nuclear unit in Connecticut, consistent with the Nuclear Resource Solution described in the January 1, 2008 Plan. The 1,200 MW nuclear unit eliminates the need to build 1,200 MW of generic gas NCC capacity, and so that amount of NCC capacity is removed from the Case, including 300 MW in Rest of Connecticut, 300 MW in SW Connecticut, 300 MW in Maine, and 300 MW in NEMASS/Boston. This leaves only 300 MW NCC capacity assumed to be built in Norwalk, 300 MW in Maine, and 600 MW in West/Central Massachusetts.

The costs and emissions in the Emissions Controls and Retirements with Nuclear Build Case differ from those in the Emissions Controls and Retirements Case in the following ways:

Cost

- ISO total going-forward resource cost: increases by $108 million due to the capital cost of the nuclear capacity minus the cost of displaced fossil generation and capacity;
- CT total going-forward resource cost: increases by $89 million, primarily due to 1,200 MW new nuclear build in Connecticut;
- CT customer cost in market regime: appears to increase by $14 million, or 0.04 cents per kWh, although this change is driven by anomalously high prices for spinning reserves in the market simulation. Without the anomalous prices, customer costs would *decrease* by approximately 0.04 cents per kWh; and
- CT customer cost in cost-of-service regime: increases by $89 million, or 0.26 cents per kWh.

Emissions

- ISO-wide emissions: NOx decreases by 863 tons (-7%), SOx decreases by 465 tons (-3%), and CO_2 decreases by 4,313,343 tons (-9%);
- CT emissions: NOx decreases by 376 tons (-14%), SOx decreases by 120 tons (-4%), and CO_2 decreases by 2,022,919 tons (-19%); and
- CT monitored NOx during top 10 peak days: decreases by 9% in Connecticut, increases by 3% in New Hampshire and decreases by 3-10% in the other states.

Other Observations

- Prices: LMPs decrease by $2 in Connecticut and increase by $4 in NEMASS/Boston, increase by $1 in Maine, and decrease by $0-1 in the rest of zones;
- Congestion: congestion on the Boston Import interface increases due to the assumption that 300 MW NCC capacity is no longer needed in NEMASS/Boston;
- Generation: coal units and NCCs run 4-7% less; and
- Winter gas use (Jan-Feb): decreases by 19% in ISO-NE and 31% in Connecticut due to the new nuclear unit replacing 1,200 MW of new gas-fired generation in Connecticut.

The investment in new nuclear capacity in the Nuclear Build Case achieves a large CO_2 reduction and more modest SOx and NOx reductions. Total ISO-wide CO_2 emissions are reduced by 4.3 million tons, or about 9 percent. On a per-ton basis, the implied cost of achieving this level of CO_2 abatement is about $38/ton of CO_2. This represents the change in the ISO-wide total going-forward resource cost in this case (without including RGGI allowance price savings), less the ISO-wide total going-forward resource cost in the Emissions Controls and Retirements Case, divided by the tons of CO_2 reduced. Compared to the $104/ton CO_2 abated through investment in renewables, nuclear investment represents a more cost-effective approach to CO_2 abatement, given the assumptions used in these cases.

Table 10 below summarizes observations on cost, emissions, and other metrics for each case analyzed.

Table 10: Summary of Costs, Emissions, and Other Metrics in Each Case

	Base Case (Industry Trends)	Renewables Buildout Case (Compared to Base Case)	Emissions Controls and Retirements (Compared to Renewables Buildout Case)	Emissions Controls and Retirements with Nuclear (Compared to Emissions Controls and Retirements Case)
ISO total going-forward resource cost	$8,630 million	↓ $222 million	↑ $491 million	↑ $108 million
CT total going-forward resource cost	$1,881 million	↑ $27 million	↑ $96 million	↑ $89 million
CT customer cost in market regime	$3,877 million	↓ $11 million	↑ $50 million	↑ $14 million
CT customer cost in cost-of-service regime	$2,163 million	↑ $27 million	↑ $96 million	↑ $89 million
ISO-wide emissions	NOx 20.3 thousand tons SOx 94.5 thousand tons CO2 51.1 million tons	NOx ↓ 5% SOx ↓ 3% CO2 ↓ 9%	NOx ↓ 37% SOx ↓ 81% CO2 ↓ 2%	NOx ↓ 7% SOx ↓ 3% CO2 ↓ 9%
CT emissions	NOx 3.7 thousand tons SOx 5.3 thousand tons CO2 10.0 million tons	NOx ↓ 3% SOx ↓ 3% CO2 ↓ 3%	NOx ↓ 26% SOx ↓ 43% CO2 ↑ 12%	NOx ↓ 14% SOx ↓ 4% CO2 ↓ 19%
CT monitored NOx during top 10 days	326 tons	↑ 3%	↓ 61%	↓ 9%
Prices	$74-75 in CT $72-76 in Massachusetts $69 in Maine $71-73 rest of ISO	↓ $1 in CT ↓ $1-2 in South ↓ $2-3 in North	↓ $3 in CT ↓ $2-4 rest of ISO	↓ $2 in CT ↑ $4 Boston and ↑ $1 ME ↓ $0-1 rest of ISO
Congestion	n/a	↑ North-South	↑ North-South	↑ Boston import
Generation	n/a	New renewable displaces gas CCs	Existing CCs run less	Coal and some NCCs run less
Winter gas use (Jan-Feb)	64.4 million MMBtu in ISO 13.0 million MMBtu in CT	↓ 19% ISO ↓ 5% in CT	↑ 6% ISO ↑ 37% CT	↓ 19% ISO ↓ 31% in CT

SUMMARY OF HIGH-LEVEL FINDINGS

The recommendations presented in the Plan are unaffected by this supplemental analysis. However, the assumptions and architecture of these additional cases, as prescribed by La Capra, would suggest the following additional findings:

1. <u>The Incremental Cost of RPS as a Result of Making the Assumed Investments is about $40/MWh</u>

Based on the availability of new renewables in the quantities and locations provided by La Capra, our assumed transmission costs, and the cost of new renewables already presented in the Plan, meeting RPS requirements increases total resource costs by $423 million relative to no RPS requirements, or about $40/MWh of new renewable generation.[10] The Connecticut-only

[10] This is an average cost for all MWh of new renewable generation, and does not represent the market-clearing price in the REC market that would be determined by a marginal unit. This average cost also includes the cost of new transmission, which would not necessarily be priced into the REC market.

resource cost of meeting RPS requirements is $275 million, and the market-based customer cost is $237 million. The resource cost represents the capital cost of the assumed renewables and associated transmission minus the costs of avoided fossil generation and capacity. The market-based customer cost reflects a $25/MWh price of RECs and the effects of renewables on energy and capacity prices.

2. <u>New Nuclear Generation is a More Cost-Effective Means to CO_2 Abatement than New Renewable Generation</u>

Based on the availability of new renewables in the quantity and locations provided by La Capra, our assumed transmission costs, and the costs of new renewables and nuclear generation already presented in the Plan, the cost of CO_2 abatement from building new nuclear generation ($38/ton CO_2 abated) is less than the cost of CO_2 abatement from building new renewables ($104/ton CO_2 abated).

3. <u>Imposing SOx and NOx Emission Rate Limits on Coal Units is Much More Effective than on Steam Oil Units</u>

Based on emission rate requirements and the cost of emission control equipment provided by La Capra, applying SOx and NOx emission rate limits on coal units achieves much greater reductions at much lower cost per ton than imposing the same emissions rate limits on steam oil units. This is because existing coal units are dispatched much more than oil units, and their current emissions rates are relatively high.

4. <u>The Environmental Retirements in Connecticut would Increase Winter Gas Use in Connecticut, Unless Offset by New Nuclear Construction</u>

Although the Renewable Buildout Case decreases projected winter power-sector gas use in both New England and Connecticut, the Emissions Controls and Retirements Case increases winter power-sector gas use by 33 percent over Base Case levels in Connecticut. A nuclear build would eliminate this increased gas use.

Appendix A

This appendix shows additional tabular comparisons of key inputs across cases. Table A.1 shows the location and amount of generic NCC capacity in all cases, and Table A.2 shows retirements and all new capacity by type and case.

Table A.1: Generic NCC Capacity, by Case

Zone	Generic NCC Capacity by Case (MW)			
	Base	Renewables Buildout	Emissions Controls and Retirements	Emissions Controls and Retirements with Nuclear
Rest of CT			300	
SW CT			300	
Norwalk			300	300
Maine	300		600	300
NEMASS/Boston			300	
WCMASS	600		600	600
Total	**900**	**0**	**2,400**	**1,200**

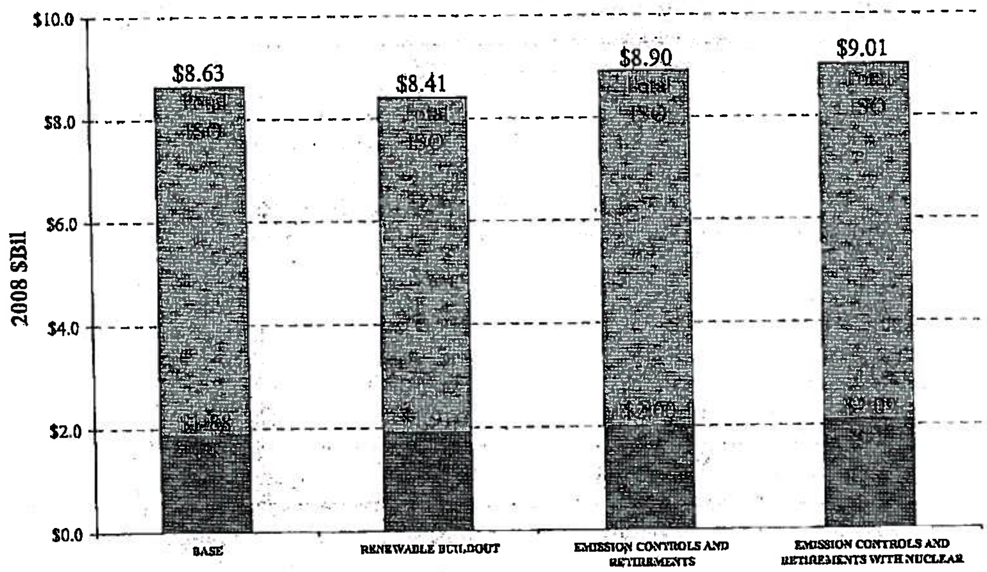
Table A.2: New and Retired Capacity, by Case (Wind capacity is derated to 20 percent)

	Total New and Retired Capacity, by Case (MW)			
	Base	Renewables Buildout	Emissions Controls and Retirements	Emissions Controls and Retirements with Nuclear
Generic NCC	900	0	2,400	1,200
New Renewable	0	947	947	947
New Nuclear				1,200
Total New Capacity	900	947	3,347	3,347
Retired Capacity			-2,655	-2,655
Net Capacity Additions	900	947	692	692

Appendix B

This appendix shows additional evaluation metrics across cases. Unless otherwise noted, these evaluation metrics are calculated as described in Appendix H of the Plan.

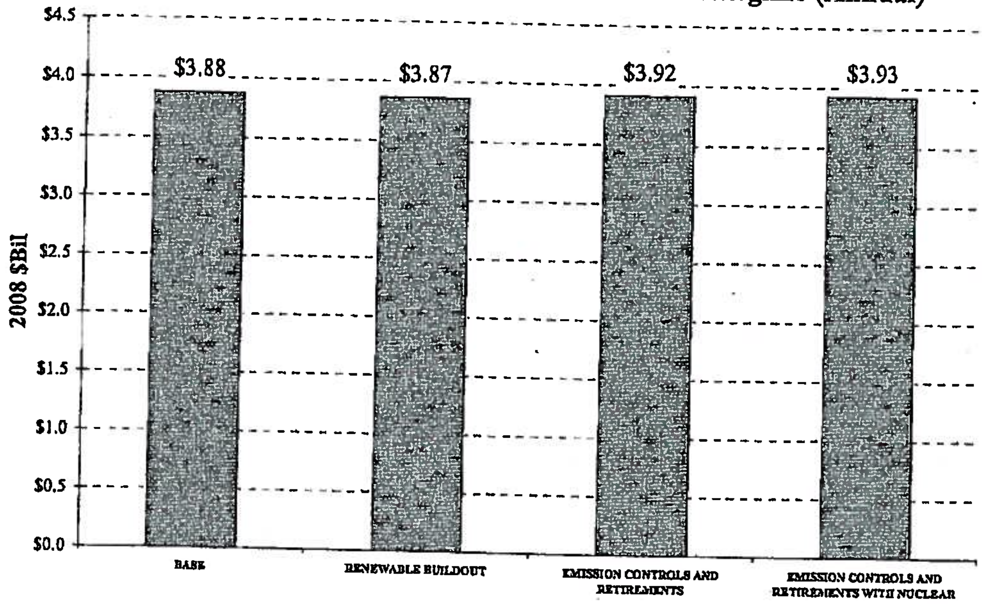
Figure B.1: ISO-NE and Connecticut Total Going-Forward Resource Cost (Annual)



*Total Resource Cost includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, energy import and export cost, net capacity import cost, and DSM program costs. Note that DSM costs for energy efficiency programs are capitalized over 10 years here; this treatment differs from that in the Customer Cost graphics, where energy efficiency program costs are expensed in the year incurred.

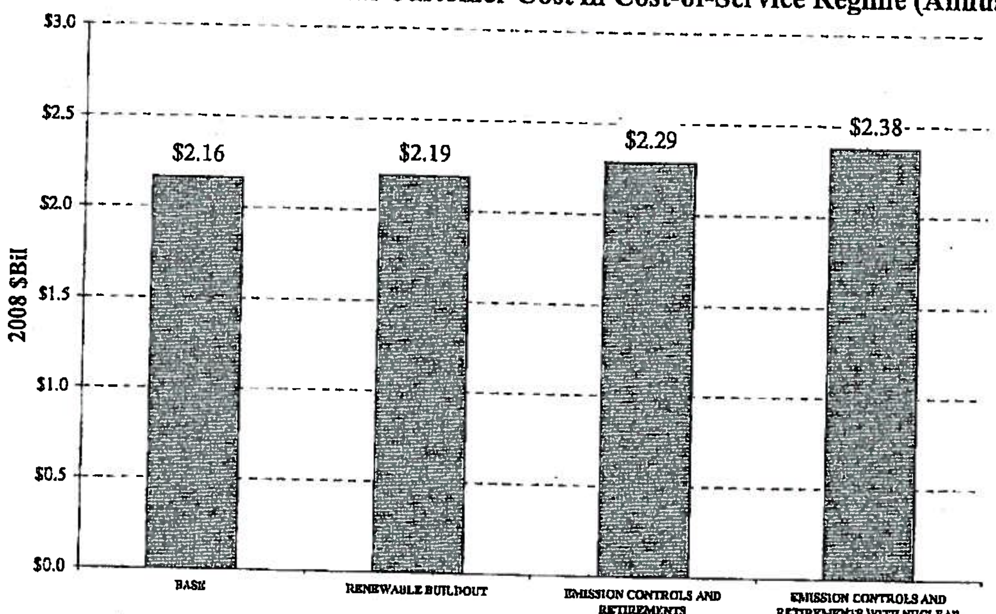
Figure B.1 above shows the total going-forward resource cost for both Connecticut and the entire ISO-NE footprint. The ISO-level resource cost was not used as an evaluation metric in the Plan and was developed to further assess the ISO-wide impact of the assumptions and architecture of these additional cases.

Figure B.2: Connecticut Total Customer Cost in Market Regime (Annual)



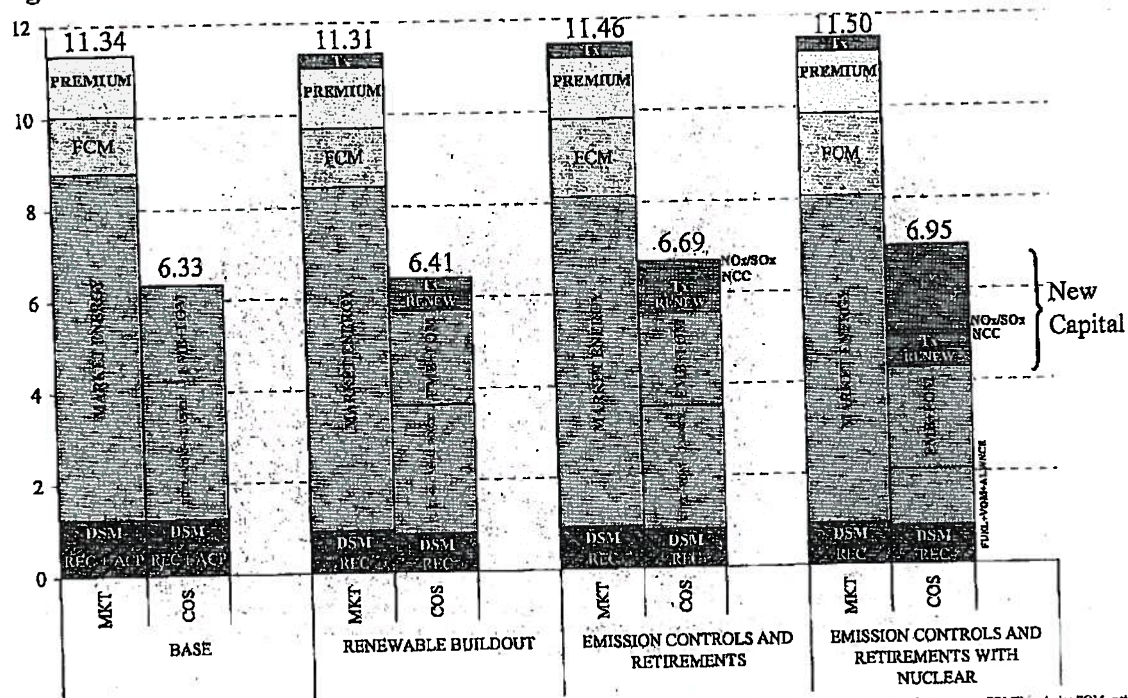
*Total Customer Cost in Market Regime includes load at LMP, capacity, FTRs, adjustment for losses, spin, uplift, fast-start, DSM program costs (expensed, not capitalized), RPS, and a 15% premium on the energy and generation components to reflect quantity risk, market price risk, and credit risk faced by wholesale suppliers of standard offer service.

Figure B.3: Connecticut Total Customer Cost in Cost-of-Service Regime (Annual)



*Total Customer Cost in Cost of Service Regime includes capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, CT energy import and export cost, net CT capacity import cost, and DSM program costs (expensed, not capitalized).

Figure B.4: Connecticut Average Customer Cost Components (¢/kWh)



Note: Market energy cost includes load at LMP, FTRs, adjustment for losses, spin, and uplift; FCM includes capacity and forward reserves; capital cost in COS regime ("EMB+FOM") includes FOM, net capacity imports, and embedded capital cost of planned and existing generation; energy cost in COS regime ("FUEL+VOM+ALWNCE") includes VOM, fuel, emissions allowances, and net energy imports. The premium added represents an estimated additional 15% on the energy and capacity components, charged by wholesale suppliers of standard offer service reflecting quantity risk, market price risk, and credit risk.

In Figure B.4, the capital cost of new transmission for imported wind ("Tx") and new renewable generation ("RENEW") is separated from the REC and ACP costs associated with RPS. New capital additions are itemized further into the capital cost of generic NCCs, the capital cost of new emissions control equipment, and the capital cost of new nuclear generation. All other cost components are as described in Appendix H of the Plan.

Figure B.5: Winter (January – February) Power Sector Gas Use in Connecticut and ISO-NE

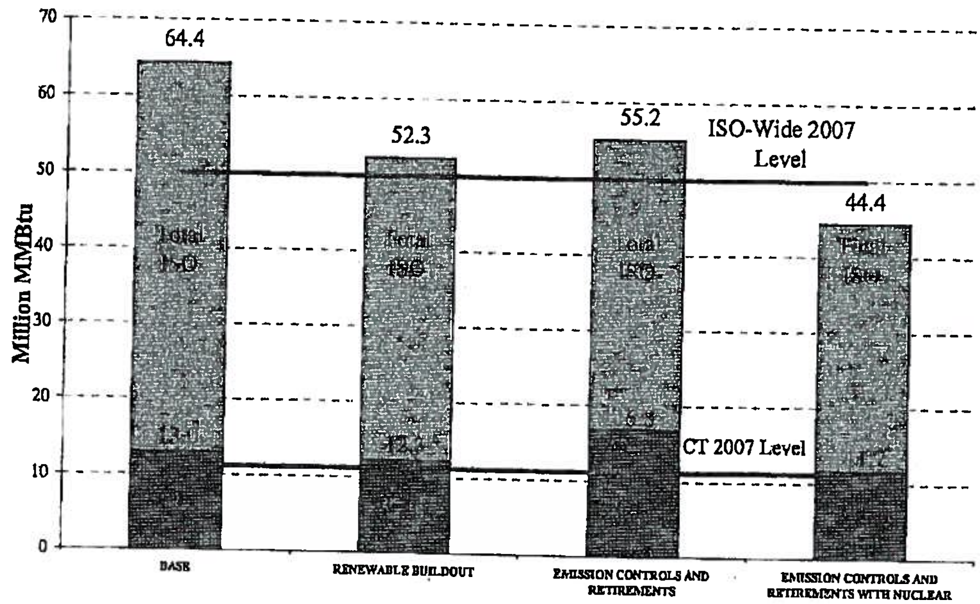


Figure B.6: Annual Power Sector Gas Use in Connecticut and ISO-NE

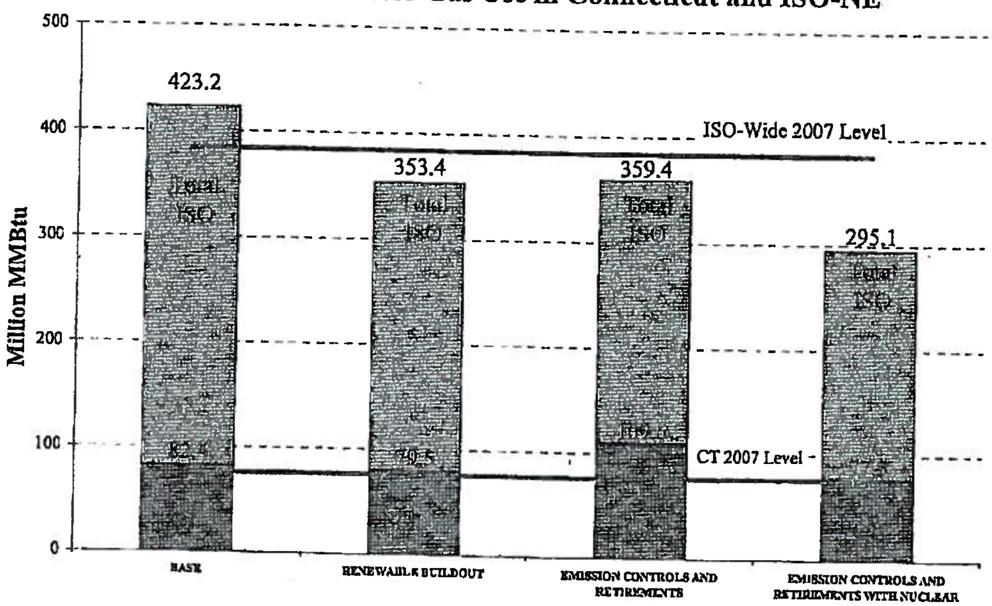


Figure B.7: Connecticut Gas-fired Generation Share of Total Generation

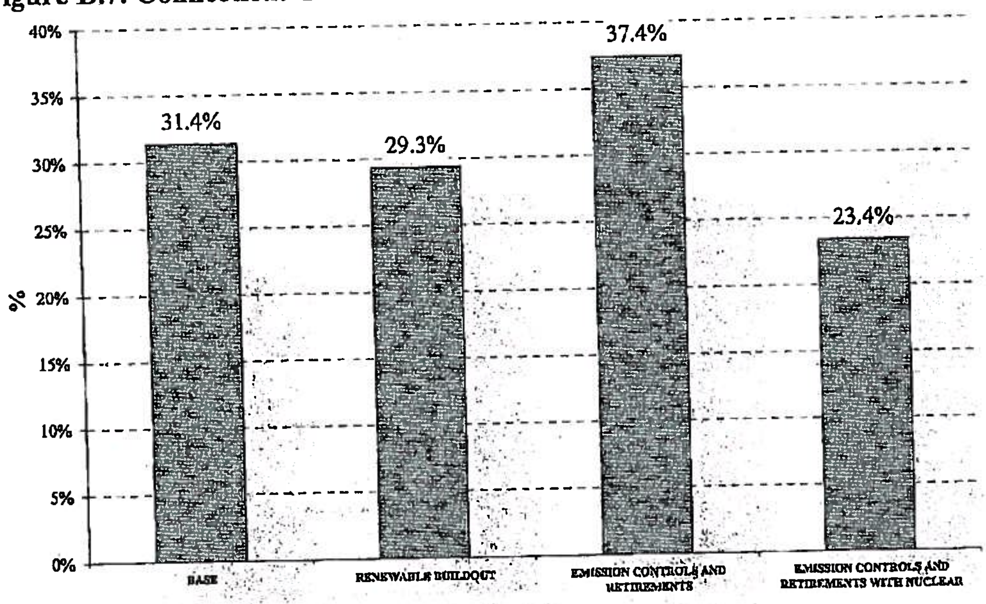


Figure B.8: ISO-NE Gas-fired Generation Share of Total Generation

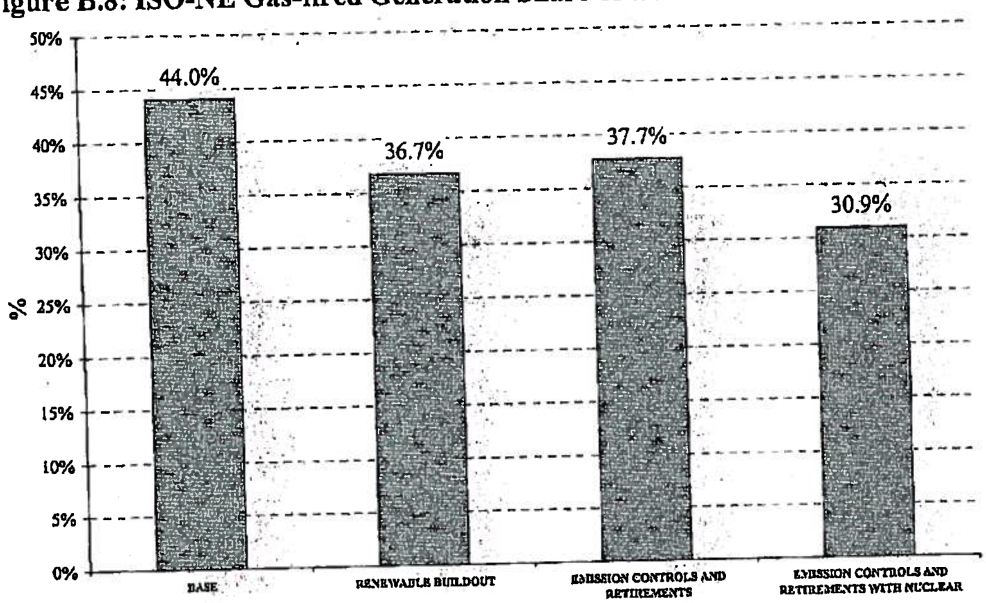


Figure B.9: Connecticut Fuel Mix (Cumulative Generation in TWh)

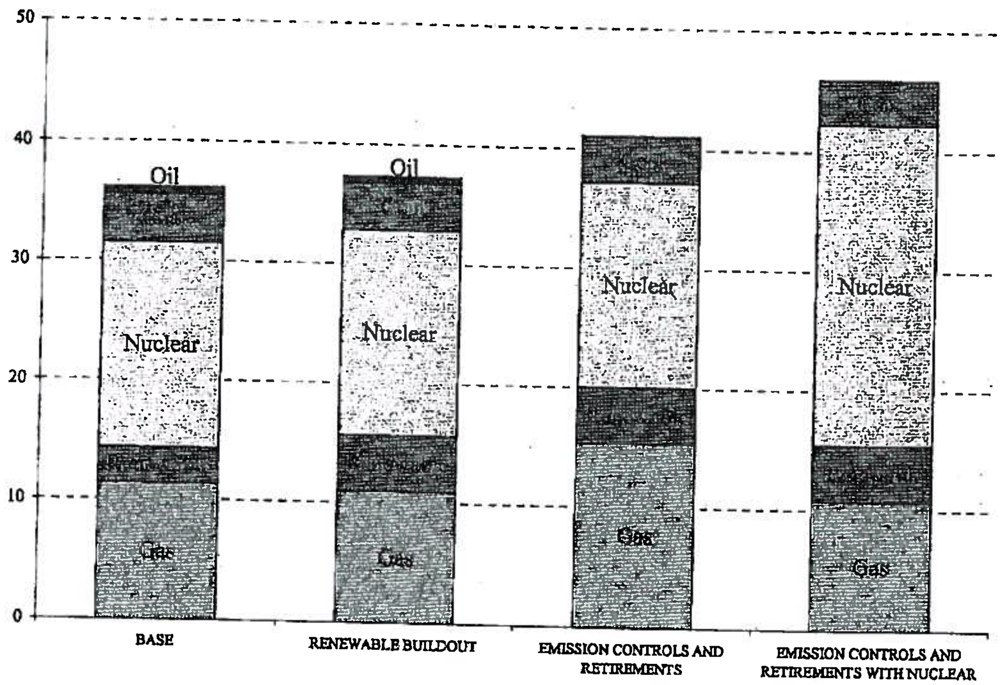


Figure B.10: Total ISO Fuel Mix (Cumulative Generation in TWh)

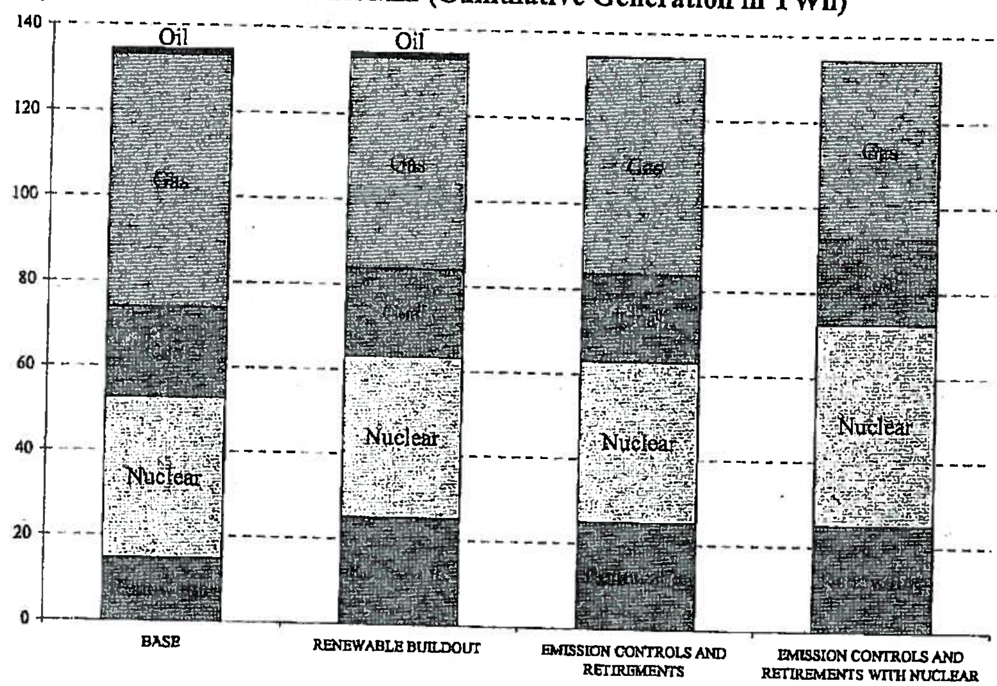
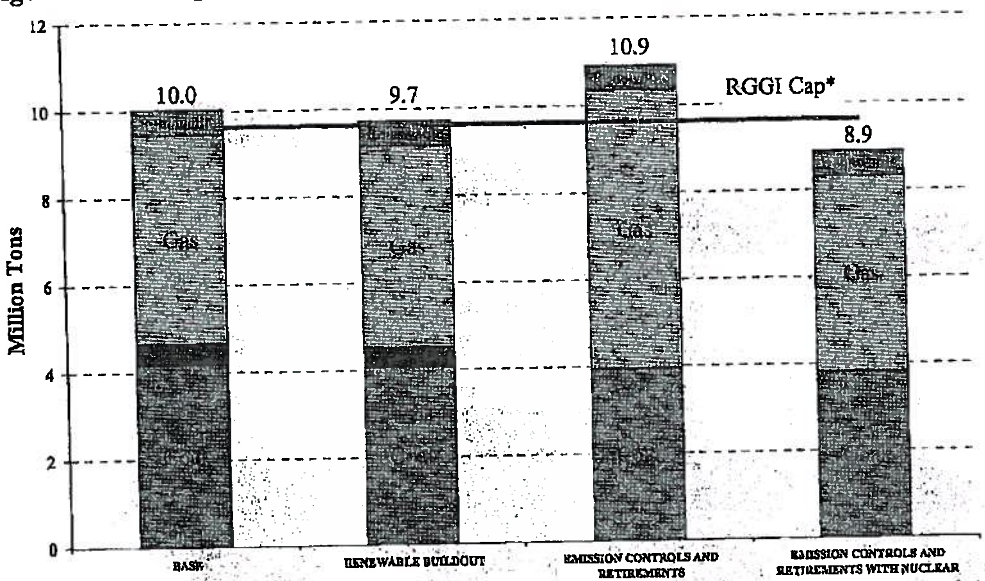
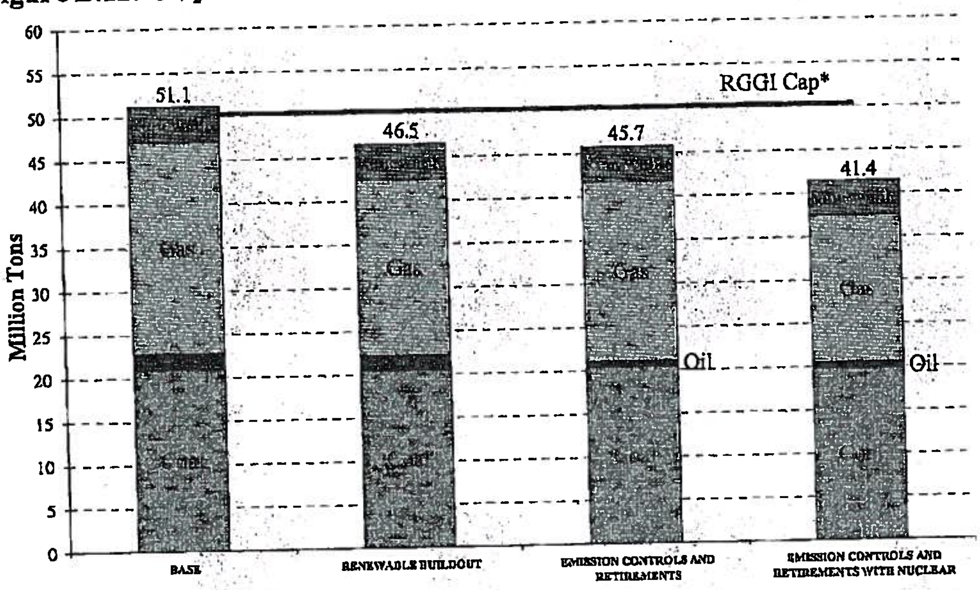


Figure B.11: CO_2 Emissions in Connecticut



*Emissions and RGGI cap shown here reflect Connecticut only. A surplus or deficiency does not indicate whole RGGI-region status.

Figure B.12: CO_2 Emissions in ISO-NE



*Emissions and RGGI cap shown here reflect the 6 member states of ISO-NE only. A surplus or deficiency does not indicate whole RGGI-region status.

Figure B.13: SOx Emissions in Connecticut

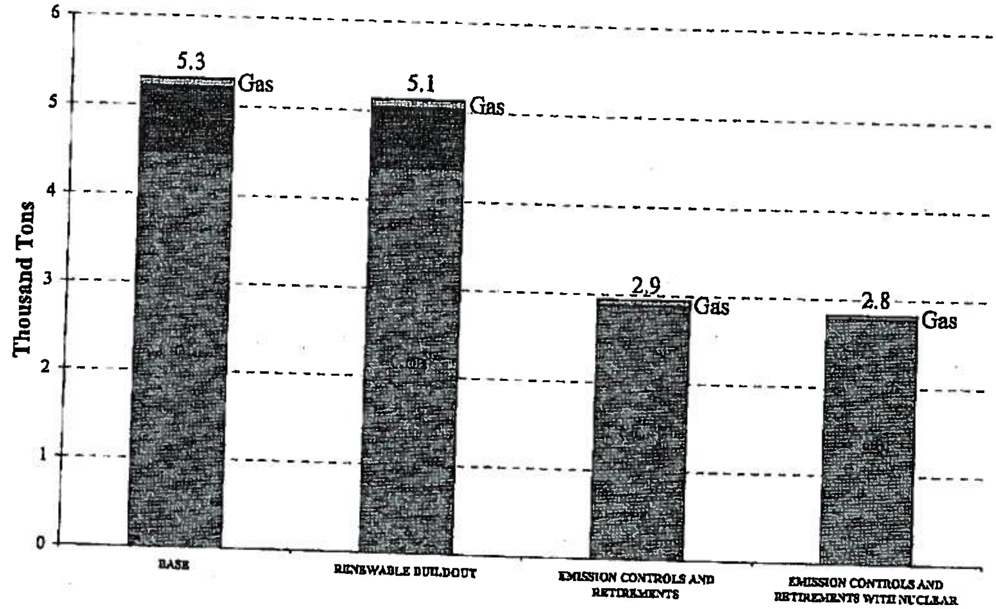


Figure B.14: SOx Emissions in ISO-NE

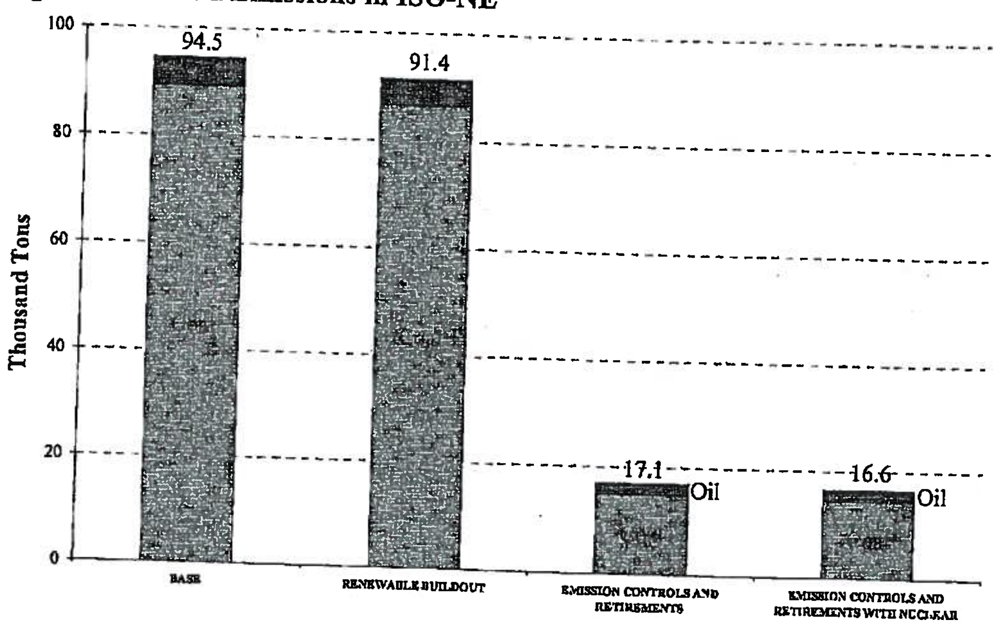


Figure B.15: NOx Emissions in Connecticut

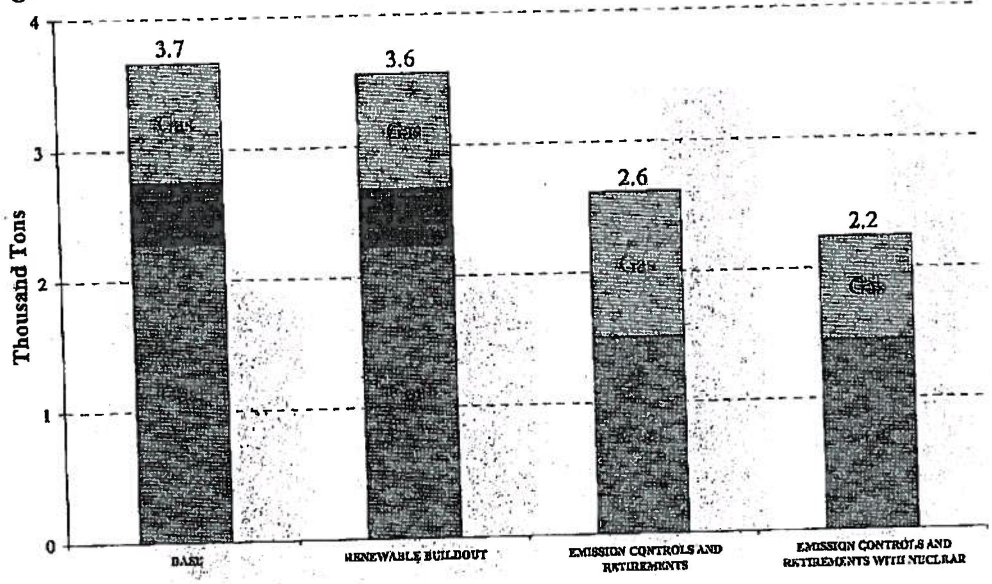


Figure B.16: NOx Emissions in ISO-NE

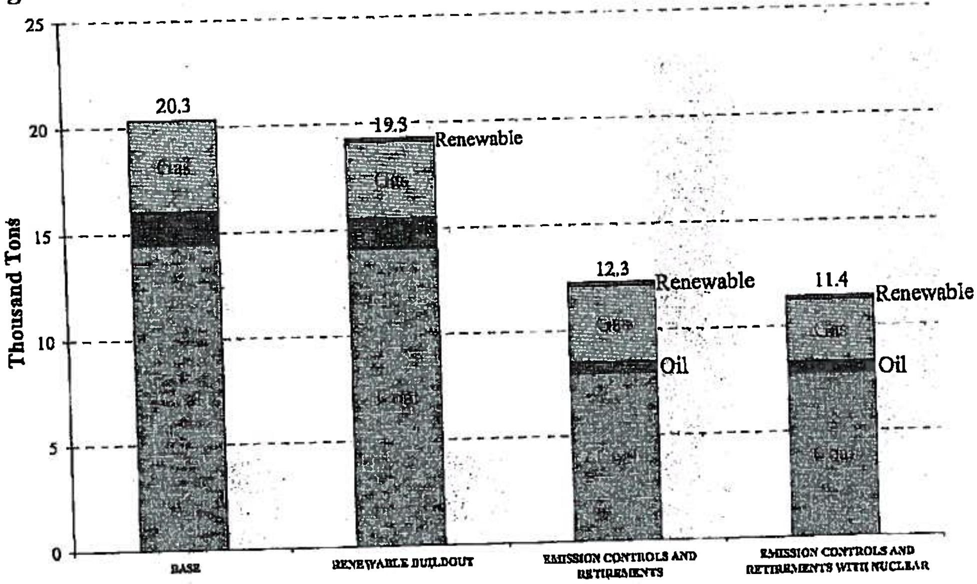


Figure B.17: NOx Emissions in Connecticut and ISO-NE (Ozone Season)

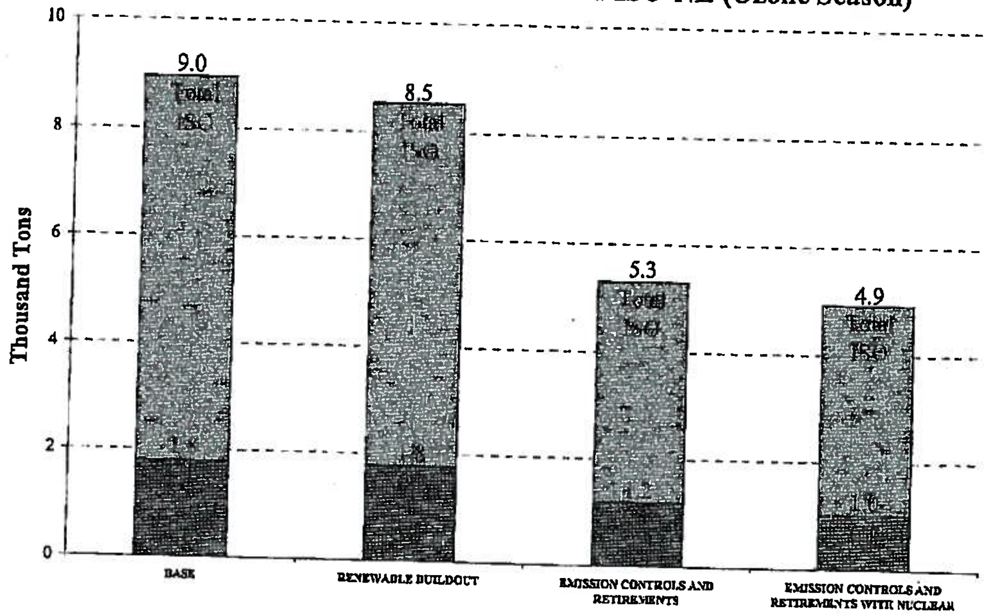
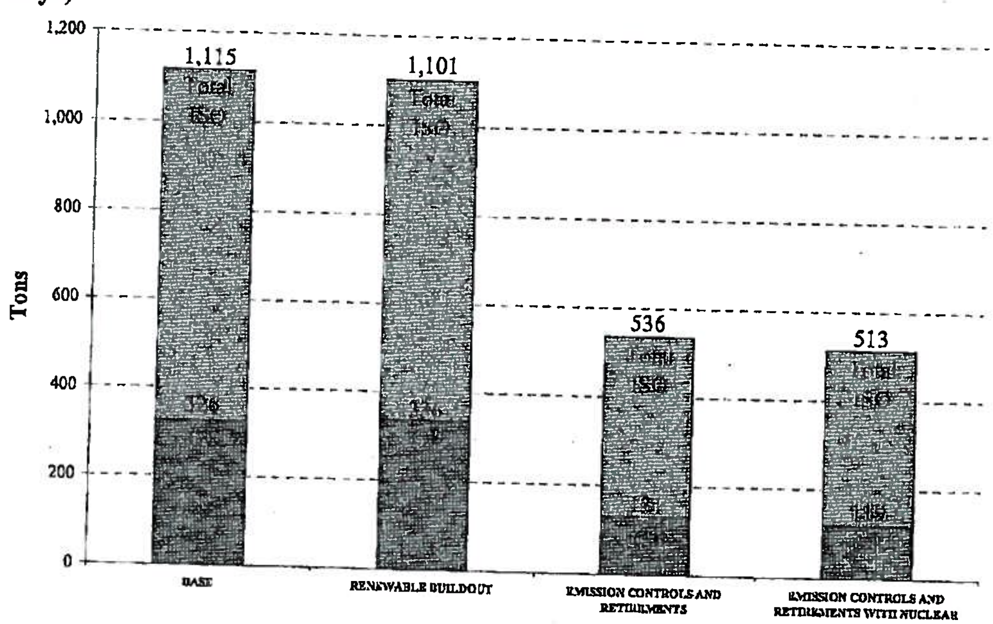


Figure B.18: NOx Emissions in Connecticut and ISO-NE (Ozone Season, Top Ten Peak Days)



Appendix C

This appendix shows the detailed metrics results for each case.

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution (La Capra Base Case)

Summary of Key Parameters in ISO-NE

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM * 1.08 loss grossup (MW)	Capacity Resource Requirement (MW)	Total Generation (MWh)	Net Imports (MWh)	Capacity Resource Requirement (MW)	Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)
78.6	74.3	57%	32,734	38,135	134,410,850	12,537,503	38,135	32,966	5,169	3.7

Total Going-Forward Resource Cost Summary for ISO-NE

Annual Capital Carrying Cost of New (Unplanned) Generation ($Mil)	Annual Capital Carrying Cost of New (Unplanned) Baseload ($Mil)	Annual Capital Carrying Costs of Environmental Controls ($Mil)	Annual Capital Carrying Costs of New Renewables ($Mil)	Annual Capital Carrying Costs of Transmission for New Renewables ($Mil)	Fixed O&M (FOM) ($Mil)	Variable O&M (VOM) ($Mil)	Cost of Fuel ($Mil)	Total Allowance Cost ($Mil)	Total RPS Cost (RECs+ ACPs+ Capital+ Transmission) ($Mil)	ISO Energy Import Cost ($Mil)	ISO Energy Export Cost ($Mil)	ISO-NE Capacity Import Cost (Negative Denotes Benefits) ($Mil)	Adder for DSM Programs ($Mil)	TOTAL RESOURCE COST ($Mil)
79	0	0	0	0	695	225	4,536	784	645	918	0	231	513	8,630

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution (La Capra Renewables Buildout Case)

Summary of Key Parameters in ISO-NE

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM * 1.08 loss grossup (MW)	Capacity Resource Requirement (MW)	Total Generation (MWh)	Net Imports (MWh)	Capacity Resource Requirement (MW)	Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)
75.4	73.1	57%	32,334	38,135	134,409,176	12,539,311	38,135	33,015	5,120	3.8

Total Going-Forward Resource Cost Summary for ISO-NE

Annual Capital Carrying Cost of New (Unplanned) Generation ($Mil)	Annual Capital Carrying Cost of New (Unplanned) Baseload ($Mil)	Annual Capital Carrying Costs of Environmental Controls ($Mil)	Annual Capital Carrying Costs of New Renewables ($Mil)	Annual Capital Carrying Costs of Transmission for New Renewables ($Mil)	Fixed O&M (FOM) ($Mil)	Variable O&M (VOM) ($Mil)	Cost of Fuel ($Mil)	Total Allowance Cost ($Mil)	Total RPS Cost (RECs+ ACPs+ Capital+ Transmission) ($Mil)	ISO Energy Import Cost ($Mil)	ISO Energy Export Cost ($Mil)	ISO-NE Capacity Import Cost (Negative Denotes Benefits) ($Mil)	Adder for DSM Programs ($Mil)	TOTAL RESOURCE COST ($Mil)
0	0	0	740	304	776	207	3,965	718	1,043	947	0	235	518	8,408

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution (La Capra Emissions Control and Retirements Case)

Summary of Key Parameters in ISO-NE

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM * 1.08 loss grossup (MW)	Capacity Resource Requirement (MW)	Total Generation (MWh)	Net Imports (MWh)	Capacity Resource Requirement (MW)	Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)
71.8	69.7	57%	32,734	38,135	134,409,131	12,539,185	38,135	32,754	5,381	5.5

Total Going-Forward Resource Cost Summary for ISO-NE

Annual Capital Carrying Cost of New (Unplanned) Generation ($Mil)	Annual Capital Carrying Cost of New (Unplanned) Baseload ($Mil)	Annual Capital Carrying Costs of Environmental Controls ($Mil)	Annual Capital Carrying Costs of New Renewables ($Mil)	Annual Capital Carrying Costs of Transmission for New Renewables ($Mil)	Fixed O&M (FOM) ($Mil)	Variable O&M (VOM) ($Mil)	Cost of Fuel ($Mil)	Total Allowance Cost ($Mil)	Total RPS Cost (RECs+ ACPs+ Capital+ Transmission) ($Mil)	ISO Energy Import Cost ($Mil)	ISO Energy Export Cost ($Mil)	ISO-NE Capacity Import Cost (Negative Denotes Benefits) ($Mil)	Adder for DSM Programs ($Mil)	TOTAL RESOURCE COST ($Mil)
216	0	356	740	304	710	255	3,929	607	1,045	908	0	355	518	8,898

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution (La Capra Emissions Control and Retirements with Nuclear Build Case)

Summary of Key Parameters in ISO-NE

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM * 1.08 loss grossup (MW)	Capacity Resource Requirement (MW)	Total Generation (MWh)	Net Imports (MWh)	Capacity Resource Requirement (MW)	Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)
73.0	69.9	57%	32,734	38,135	134,407,333	12,541,264	38,135	32,757	5,378	5.9

Total Going-Forward Resource Cost Summary for ISO-NE

Annual Capital Carrying Cost of New (Unplanned) Generation ($Mil)	Annual Capital Carrying Cost of New (Unplanned) Baseload ($Mil)	Annual Capital Carrying Costs of Environmental Controls ($Mil)	Annual Capital Carrying Costs of New Renewables ($Mil)	Annual Capital Carrying Costs of Transmission for New Renewables ($Mil)	Fixed O&M (FOM) ($Mil)	Variable O&M (VOM) ($Mil)	Cost of Fuel ($Mil)	Total Allowance Cost ($Mil)	Total RPS Cost (RECs+ ACPs+ Capital+ Transmission) ($Mil)	ISO Energy Import Cost ($Mil)	ISO Energy Export Cost ($Mil)	ISO-NE Capacity Import Cost (Negative Denotes Benefits) ($Mil)	Adder for DSM Programs ($Mil)	TOTAL RESOURCE COST ($Mil)
107	583	356	740	304	815	246	3,501	547	1,045	910	0	378	518	9,006

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution (La Capra Base Case)

Summary of Key Parameters in Connecticut

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM + 1.88 MW grossup (MW)	Total Energy Needed to Meet Customer Load (MWh)	Total Generation in Connecticut (MWh)	Net Imports (MWh)	CT LSR/ICR (MW)	CT Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)	Fast-Start Price ($/kW-Mo)	Fast-Start Requirement (MW)
76.5	74.5	57%	6,796	34,173,972	36,173,660	-2,626,551	7,917	8,251	-334	3.7	10.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Annual Capital Carrying Cost of New (Unplanned) Generation in CT ($Mil)	Annual Capital Carrying Cost of New (Unplanned) Demand in CT ($Mil)	Annual Capital Carrying Costs of Environmental Controls in CT ($Mil)	Annual Capital Carrying Costs of New Renewables in CT ($Mil)	Annual Capital Carrying Costs of Transmission for New Renewables in CT ($Mil)	Fixed O&M (FOM) ($Mil)	Variable O&M (VOM) ($Mil)	Cost of Fuel ($Mil)	Total Allowance Cost ($Mil)	Total RPS Cost (RECs + ACPs + Capital + Transmission) ($Mil)	CT Energy Import Cost ($Mil)	CT Energy Export Cost ($Mil)	CT Capacity Import Cost (Negative Denotes Benefits) ($Mil)	Adder for DSM Programs ($Mil)	TOTAL RESOURCE COST ($Mil)
0	0	0	0	0	314	82	1,015	142	248	67	-343	-45	303	1,881

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP ($Mil)	ICR*Price ($Mil)	FTRs (Assume 75% Coverage for Internal Cost to Load) ($Mil)	Adjustment for Overcounting Losses ($Mil)	Uplift [illegible] ($Mil)	Uplift ($Mil)	Contracted Fast-Start Cost ($Mil)	TOTAL GENERATION SVC COST + 15% PREMIUM ($Mil)	AVERAGE GENERATION SVC COST + 15% PREMIUM (¢/kWh)	Adder for DSM Programs ($Mil)	Additional RPS Cost (RECs + ACPs + Transmission) ($Mil)	TOTAL SYSTEM BENEFITS COST ($Mil)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($Mil)	AVG COST (¢/kWh)
2,633	353	-2	-44	21	4	73	3,455	10.11	172	249	421	1.23	3,877	11.34

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS ($Mil)	Annualized Embedded Cost of Generators ($Mil)	TOTAL GENERATION SVC COST ($Mil)	AVERAGE GENERATION SVC COST (¢/kWh)	Adder for DSM Programs ($Mil)	Total RPS Cost (RECs + ACPs + Capital + Transmission) ($Mil)	TOTAL SYSTEM BENEFITS COST ($Mil)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($Mil)	AVG COST (¢/kWh)
1,330	413	1,743	5.10	172	248	421	1.23	2,163	6.33

Electric Reliability and Availability

ISO-NE Reserve Margin (%)	CT LSR Surplus (Deficit) (MW)
15.1%	3,032

Fuel Security

CT NG Demand in January and February (MMBtu)	CT NG Demand in July and August (MMBtu)	Total CT NG Demand (MMBtu)	CT NG Share of Total CT Generation (%)	ISO-NE NG Demand in January and February (MMBtu)	ISO NG Demand in July and August (MMBtu)	Total ISO-NE NG Demand (MMBtu)
13,936,313	17,293,064	82,418,554	31%	64,374,125	84,216,955	433,190,361

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SO2 Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SO2 Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	16,411,988	3,304	3,636	10,834,091	3,306	3,659
ME	4,675,197	3,367	1,717	6,675,833	4,383	1,326
MA	23,364,550	46,547	9,631	23,381,343	46,535	9,632
NH	6,621,233	38,453	4,760	8,621,537	39,433	4,761
RI	2,597,570	22	449	2,597,974	22	449
VT	333,914	1	1	333,596	1	2
Total	61,105,603	94,633	20,297	61,340,338	94,491	20,322

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewable Requirement (%)	Class I Renewable Requirement	Class II Renewable Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,370,310	615,300	2,955,660	36,173,660	34,173,972						
2,117,110	3,021,130	5,038,230	17,577,306	13,307,015						
1,781,950	1,063,130	2,834,070	43,381,210	46,657,773						
796,130	2,624,540	3,730,690	31,103,260	13,947,083						
95,290	0	95,290	6,222,570	12,863,821						
330,530	439,150	927,780	6,136,430	8,272,716						
7,563,550	7,166,740	14,649,610	134,418,650	147,614,381						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Wind Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,370,080	615,300	0	17,180,830	4,834,270	11,347,030	33,360	593,570	11,864,850	24,310,810	36,173,660
ME	2,117,110	3,021,130	0	0	666,320	11,537,470	750	140,570	11,677,900	5,899,400	17,577,306
MA	1,781,950	1,063,130	0	5,357,350	13,372,600	22,447,340	21,770	541,540	22,576,600	20,805,610	43,381,210
NH	796,130	2,624,540	0	10,660,370	4,305,190	9,143,220	1,360	0	9,144,540	14,840,750	23,985,290
RI	95,290	0	0	0	0	6,137,280	0	0	6,137,280	95,290	6,232,570
VT	330,530	439,150	0	5,163,370	0	13,190	2,280	0	15,380	4,133,070	4,148,450
Total	7,563,870	7,166,740	0	37,942,000	22,374,530	60,534,390	59,570	1,325,370	61,923,740	73,185,113	134,418,658

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution (La Capra Renewables Buildout Case)

Summary of Key Parameters in Connecticut

Load LMP	Generation LMP	Load Factor	Peak Load Net of DSM * 1.0X less grossup	Total Energy Needed to Meet Customer Load	Total Generation in Connecticut	Net Imports	CT LSR/ ICR	CT Internal Installed Capacity	Net Capacity Imports (negative denotes exports)	Capacity Price	Fast-Start Price	Fast-Start Requirement
($/MWh)	($/MWh)		(MW)	(MWh)	(MWh)	(MWh)	(MW)	(MW)	(MW)	($/kW-Mo)	($/kW-Mo)	(MW)
78.2	73.7	57%	6,700	34,373,972	37,354,826	-3,857,490	7,917	8,381	-464	3.8	14.2	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Annual Capital Carrying Cost of New (Unplanned) Generation in CT	Annual Capital Carrying Cost of New (Unplanned) Baseload in CT	Annual Capital Carrying Costs of Environmental Controls in CT	Annual Capital Carrying Costs of New Renewables in CT	Annual Capital Carrying Costs of Transmission for New Renewables in CT	Fixed O&M (FOM)	Variable O&M (VOM)	Cost of Fuel	Total Allowance Cost	Total RPS Cost (RECs+ ACPs+ Capital+ Transmission)	CT Energy Import Cost	CT Energy Export Cost	CT Capacity Import Cost (Negative Denotes Benefits)	Adder for DSM Programs	TOTAL RESOURCE COST
($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)
8	0	0	127	181	314	90	867	157	353	52	-266	-21	303	1,998

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP	ICR*Price	FTRs (Assume 75% Coverage for Internal Gen to Load)	Adjustment for Overcounting Losses	Sync	Uplift	Connecticut Fast-Start Cost	TOTAL GENERATION SVC COST + 15% PREMIUM	AVERAGE GENERATION SVC COST + 15% PREMIUM	Adder for DSM Programs	Additional RPS Cost (RECs+ ACPs+ Transmission)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	(¢/kWh)	($MM)	($MM)	($MM)	(¢/kWh)	($MM)	(¢/kWh)
2,684	364	-3	-43	23	5	71	3,481	10.10	172	383	418	1.22	3,884	11.31

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS	Annualized Embedded Cost of Generation	TOTAL GENERATION SVC COST	AVERAGE GENERATION SVC COST	Adder for DSM Programs	Total RPS Cost (RECs+ ACPs+ Capital+ Transmission)	TOTAL SYSTEM BENEFITS COST	AVERAGE SYSTEM BENEFITS COST	TOTAL COST	AVG COST
($MM)	($MM)	($MM)	(¢/kWh)	($MM)	($MM)	($MM)	(¢/kWh)	($MM)	(¢/kWh)
1,252	413	1,666	4.87	172	353	526	1.54	2,191	6.41

Electric Reliability and Availability

ISO-NE Reserve Margin	CT LSR Surplus (Deficit)
(%)	(MW)
34.2%	1,163

Fuel Security

CT NG Demand in January and February	CT NG Demand in July and August	Total CT NG Demand	CT NG Share of Total CT Generation	ISO-NE NG Demand in January and February	ISO NG Demand in July and August	Total ISO-NE NG Demand
(MMBtu)		(MMBtu)	(%)	(MMBtu)		(MMBtu)
12,885,563	17,322,810	79,480,411	29%	52,282,183	38,372,577	253,433,209

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units	Total SOx Emissions - Monitored Units	Total NOx Emissions - Monitored Units	Total CO2 Emissions - All Units	Total SOx Emissions - All Units	Total NOx Emissions - All Units
	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)	(Tons)
CT	8,903,335	5,129	3,550	9,714,825	5,134	3,532
ME	5,353,990	3,348	1,482	5,394,477	3,983	1,463
MA	20,889,571	45,553	9,800	20,907,590	45,574	7,463
NH	7,348,183	36,718	4,521	7,512,811	36,718	9,318
RI	2,392,792	21	413	2,382,792	21	4,570
VT	533,831	1	1	538,145	1	413
						51
Total	46,421,434	90,909	19,815	46,460,260	91,430	23,288

RPS Summary

Biomass and Refuse Generation	Hydro Generation	Renewable Generation	Total Generation	Total Retail Sales	Overall Renewables Requirement	Class I Renewables Requirement	Class II Renewables Requirement	Class I Eligible Renewable Generation	Class II Eligible Renewable Generation	Alternative Compliance Payments
(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(%)		(%)	(MWh)	(MWh)	($)
3,451,280	631,430	4,703,116	37,534,826	34,173,971						
3,583,340	3,047,300	7,844,540	17,072,780	15,807,812						
2,230,300	963,290	4,664,780	39,797,410	64,457,772						
1,228,780	2,043,138	3,182,490	36,548,510	12,047,800						
114,450	0	114,414	3,745,850	12,665,821						
918,120	481,080	2,449,800	7,818,000	8,372,718						
10,849,240	7,168,310	25,351,420	134,489,174	147,824,301						

Fuel Usage Summary

State	Biomass and Refuse Generation	Hydro Generation	Wind Generation	Nuclear Generation	Coal Generation	Natural Gas Generation	Distillate Fuel Oil Generation	Residual Fuel Oil Generation	Total Gas or Oil Generation	Total NOT Gas or Oil Generation	Total Generation
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
CT	3,451,280	631,420	1,622,636	17,180,880	3,041,260	10,964,000	27,330	337,770	11,329,130	25,877,484	37,354,826
ME	3,583,340	3,047,390	1,211,810	0	612,100	8,170,780	490	114,710	8,533,960	8,430,850	17,072,780
MA	2,230,300	963,290	1,451,200	3,597,800	12,151,020	16,864,090	26,100	481,990	17,383,080	22,414,330	39,797,410
NH	1,228,780	2,043,138	1,378,330	10,800,870	4,025,100	7,182,520	1,480	0	9,290,090	19,178,500	36,548,510
RI	114,450	0	0	0	0	3,631,400	0	0	3,631,400	114,450	3,745,850
VT	918,120	481,080	1,260,000	5,163,370	0	12,500	2,000	0	14,500	7,833,170	7,818,000
Total	10,849,240	7,168,310	7,433,876	37,942,800	20,260,420	49,251,290	57,400	1,144,470	50,554,350	83,854,826	134,489,174

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution (La Capra Emissions Control and Retirements Case)

Summary of Key Parameters in Connecticut

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load factor	Peak Load Net of DSM + 1.87 Loss gross-up (MW)	Total Energy Needed to Meet Customer Load (MWh)	Total Generation in Connecticut (MWh)	Net Imports (MWh)	CT LSR/ LCR (MW)	CT Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)	Fast-Start Price ($/kW-Mo)	Fast-Start Requirement (MW)
73.0	70.8	57%	6,790	34,173,972	41,080,986	-7,581,837	7,077	9,011	-84	5.5	8.5	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Annual Capital Carrying Cost of New (Unplanned) Generation in CT ($MM)	Annual Capital Carrying Cost of New (Unplanned) Demand in CT ($MM)	Annual Capital Carrying Costs of Environmental Controls in CT ($MM)	Annual Capital Carrying Costs of New Renewables in CT ($MM)	Annual Capital Carrying Costs of Transmission for New Renewables in CT ($MM)	Fixed O&M (FOM) ($MM)	Variable O&M (VOM) ($MM)	Cost of Fuel ($MM)	Total Allowance Cost ($MM)	Total RPS Cost (RECs+ ACPs+ Capital+ Transmission) ($MM)	CT Energy Import Cost ($MM)	CT Energy Export Cost ($MM)	CT Capacity Import Cost (Negative Denotes Benefits) ($MM)	Adder for DSM Programs ($MM)	TOTAL RESOURCE COST ($MM)
85	0	62	137	181	290	58	1,137	145	353	0	-453	-4	303	2,095

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP ($MM)	ICR*Price ($MM)	FTRs (Assume 75% Coverage for Internal Gen to Load) ($MM)	Adjustment for Overcounting Losses ($MM)	Spin ($MM)	Uplift ($MM)	Committed Fast-Start Cost ($MM)	TOTAL GENERATION SVC COST + 15% PREMIUM ($MM)	AVERAGE GENERATION SVC COST + 15% PREMIUM (¢/kWh)	Adder for DSM Programs ($MM)	Additional RPS Cost (RECs+ ACPs+ Transmission) ($MM)	TOTAL SYSTEM BENEFITS COST ($MM)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($MM)	AVG COST (¢/kWh)
2,493	822	-4	-35	18	7	66	3,600	10.34	172	243	416	1.22	3,910	11.46

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS ($MM)	Annualized Embedded Cost of Generators ($MM)	TOTAL GENERATION SVC COST ($MM)	AVERAGE GENERATION SVC COST (¢/kWh)	Adder for DSM Programs ($MM)	Total RPS Cost (RECs+ ACPs+ Capital+ Transmission) ($MM)	TOTAL SYSTEM BENEFITS COST ($MM)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($MM)	AVG COST (¢/kWh)
1,349	415	1,763	5.16	172	353	825	1.54	2,297	6.69

Electric Reliability and Availability

ISO-NE Reserve Margin (%)	CT LSR Surplus (Deficit) (MW)
22.4%	2,794

Fuel Security

CT NG Demand in January and February (MMBtu)	CT NG Demand in July and August	Total CT NG Demand (MMBtu)	CT NG Share of Total CT Generation (%)	ISO-NE NG Demand in January and February (MMBtu)	ISO-NE NG Demand in July and August	Total ISO-NE NG Demand (MMBtu)
16,608,437	23,706,432	109,626,380	37%	55,180,643	86,305,183	391,309,973

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	10,883,150	2,940	2,611	10,904,878	2,943	2,613
ME	6,058,965	417	826	6,047,828	417	831
MA	19,946,549	8,818	5,852	19,976,118	8,821	4,914
NH	6,626,630	4,863	2,454	6,829,229	4,963	2,901
RI	1,414,994	72	344	1,414,994	13	344
VT	533,295	1	1	534,324	1	20
Total	45,724,486	17,050	12,000	46,745,240	17,052	12,253

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewables Requirement (%)	Class I Renewables Requirement	Class II Renewables Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payments ($)
2,451,260	451,300	4,705,246	41,080,986	34,173,972						
3,366,000	3,847,500	7,234,390	19,631,090	13,307,815						
2,290,210	963,231	4,414,630	38,253,028	66,652,773						
1,228,490	2,045,390	3,152,430	11,730,840	12,047,319						
114,260	0	114,260	3,466,060	12,663,821						
919,130	481,260	2,669,970	7,343,036	8,372,718						
10,633,470	7,108,910	23,155,076	134,409,121	147,424,301						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Wind Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,151,264	451,340	1,622,486	17,140,880	3,825,820	15,332,548	16,820	0	15,360,960	25,71[illegible],926	41,080,986
ME	3,366,000	3,847,500	1,311,810	0	384,440	10,626,380	666	0	10,627,240	9,003,830	19,631,090
MA	2,290,210	963,231	1,451,200	5,597,880	12,086,450	15,923,760	16,250	23,050	15,966,080	22,282,940	38,253,028
NH	1,228,490	2,045,360	1,378,520	10,840,870	4,173,690	5,402,180	1,636	0	5,404,150	19,326,790	24,730,940
RI	114,260	0	0	0	0	3,351,800	0	0	3,351,800	114,260	3,466,060
VT	919,130	451,260	1,369,880	3,163,370	0	9,730	2,516	0	11,746	7,333,290	7,343,036
Total	10,063,420	7,108,940	9,433,878	37,042,000	20,660,180	50,668,219	39,436	23,050	50,730,696	83,678,424	134,409,121

Summary of Results: 2018 Current Trends Scenario, DSM-Focus Solution (La Capra Emissions Control and Retirements with Nuclear Build Case)

Summary of Key Parameters in Connecticut

Load LMP ($/MWh)	Generation LMP ($/MWh)	Load Factor	Peak Load Net of DSM + 1.5% load growth (MW)	Total Energy Needed to Meet Consumer Load (MWh)	Total Generation in Connecticut (MWh)	Net Imports (MWh)	CT LSR (MW)	CT Internal Installed Capacity (MW)	Net Capacity Imports (negative denotes exports) (MW)	Capacity Price ($/kW-Mo)	Fast-Start Price ($/kW-Mo)	Fast-Start Requirement (MW)
71.6	68.7	57%	6,7[illegible]	34,173,972	46,025,646	12,526,414	7,977	8,613	-495	5.9	0.1	1,300

Total Going-Forward Resource Cost Summary for Connecticut

Annual Capital Carrying Cost of New (Unplanned) Generation in CT ($M)	Annual Capital Carrying Cost of New (Unplanned) Demand in CT ($M)	Annual Capital Carrying Costs of Environmental Controls in CT ($M)	Annual Capital Carrying Costs of New Renewables in CT ($M)	Annual Capital Carrying Costs of Transmission for New Renewables in CT ($M)	Fixed O&M (FOM) ($M)	Variable O&M (VOM) ($M)	Cost of Fuel ($M)	Total Allowance Cost ($M)	Total RPS Cost (RECs + ACPs + Capital + Transmission) ($M)	CT Energy Import Cost ($M)	CT Energy Export Cost ($M)	CT Capacity Import Cost (Negative Denotes Benefits) ($M)	Adder for DSM Programs ($M)	TOTAL RESOURCE COST ($M)
28	287	61	137	101	306	62	1,019	120	153	1	-790	-43	163	2,894

Total and Average Customer Cost in Connecticut (Market Regime)

Load*LMP ($M)	ICR*Price ($M)	FTRs (Assume 75% Coverage for Internal Gen in Load) ($M)	Adjustment for Overcounting Losses ($M)	Sync ($M)	Uplift ($M)	Connecticut Fast-Start Cost ($M)	TOTAL GENERATION SVC COST + 10% PREMIUM ($M)	AVERAGE GENERATION SVC COST + 10% PREMIUM (¢/kWh)	Adder for DSM Programs ($M)	Additional RPS Cost (RECs + ACPs + Transmission) ($M)	TOTAL SYSTEM BENEFITS COST ($M)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($M)	AVG COST (¢/kWh)
2,447	356	0	-48	56	6	57	3,014	10.38	172	313	416	1.22	3,919	11.60

Total and Average Customer Cost in Connecticut (Cost of Service Regime)

Total Going-Forward Resource Cost Minus DSM and RPS ($M)	Annualized Embedded Cost of Generation ($M)	TOTAL GENERATION SVC COST ($M)	AVERAGE GENERATION SVC COST (¢/kWh)	Adder for DSM Programs ($M)	Total RPS Cost (RECs + ACPs + Capital + Transmission) ($M)	TOTAL SYSTEM BENEFITS COST ($M)	AVERAGE SYSTEM BENEFITS COST (¢/kWh)	TOTAL COST ($M)	AVG COST (¢/kWh)
1,439	411	1,851	5.42	172	353	528	1.54	2,376	6.95

Electric Reliability and Availability

ISO-NE Reserve Margin (%)	CT LSR Surplus (Deficit) (MW)
23.4%	3,393

Fuel Security

CT NG Demand in January and February (MMBtu)	CT NG Demand in July and August	Total CT NG Demand (MMBtu)	CT NG Share of Total CT Generation (%)	ISO-NE NG Demand in January and February (MMBtu)	ISO NG Demand in July and August	Total ISO-NE NG Demand (MMBtu)
11,063,169	17,810,984	77,303,348	23%	41,420,603	76,256,013	295,057,072

ISO-NE Emissions by State

State	Total CO2 Emissions - Monitored Units (Tons)	Total SOx Emissions - Monitored Units (Tons)	Total NOx Emissions - Monitored Units (Tons)	Total CO2 Emissions - All Units (Tons)	Total SOx Emissions - All Units (Tons)	Total NOx Emissions - All Units (Tons)
CT	5,876,361	2,820	2,339	8,383,700	3,822	2,297
ME	3,420,083	486	810	5,421,316	496	715
MA	16,531,856	8,567	5,539	16,533,934	8,852	5,761
NH	6,778,054	4,750	2,417	6,772,700	4,760	2,483
RI	1,204,515	11	223	1,293,513	11	323
VT	528,376	1	1	331,175	1	50
Total	41,399,397	16,605	11,334	41,435,897	16,893	11,190

RPS Summary

Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Renewable Generation (MWh)	Total Generation (MWh)	Total Retail Sales (MWh)	Overall Renewable Requirement (%)	Class I Renewable Requirement	Class II Renewable Requirement (%)	Class I Eligible Renewable Generation (MWh)	Class II Eligible Renewable Generation (MWh)	Alternative Compliance Payment ($)
2,432,900	630,430	4,681,060	46,025,646	34,173,872						
3,585,600	3,043,000	9,324,259	17,381,600	13,807,815						
2,234,540	949,700	4,626,440	35,232,196	44,457,772						
1,219,720	3,043,430	3,311,730	34,342,530	12,847,303						
112,980	0	112,980	3,176,330	12,663,021						
913,140	430,858	2,663,850	7,830,983	8,272,718						
10,483,950	7,139,150	25,854,771	134,487,313	147,624,301						

Fuel Usage Summary

State	Biomass and Refuse Generation (MWh)	Hydro Generation (MWh)	Wind Generation (MWh)	Nuclear Generation (MWh)	Coal Generation (MWh)	Natural Gas Generation (MWh)	Distillate Fuel Oil Generation (MWh)	Residual Fuel Oil Generation (MWh)	Total Gas or Oil Generation (MWh)	Total NOT Gas or Oil Generation (MWh)	Total Generation (MWh)
CT	2,432,900	630,430	1,622,690	20,862,310	2,494,160	16,764,640	14,230	0	10,780,870	35,244,436	46,025,646
ME	3,585,600	3,043,000	1,311,010	0	256,231	9,809,670	1,290	0	9,810,960	8,380,640	17,381,600
MA	2,234,540	949,700	1,411,300	5,387,800	11,392,400	13,160,700	33,110	30,300	13,224,410	22,002,700	35,232,196
NH	1,219,720	3,043,430	1,378,940	16,091,870	4,064,800	9,533,110	1,740	0	9,535,930	19,207,430	34,342,530
RI	112,980	0	0	0	0	3,063,290	0	0	3,063,290	112,980	3,176,330
VT	913,140	430,858	1,289,980	5,163,370	0	9,350	2,040	0	12,370	7,324,760	7,830,983
Total	10,483,950	7,139,150	7,423,970	47,623,310	20,907,970	41,563,623	43,315	30,300	41,635,977	92,301,256	134,487,232

ORIGINAL
N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-7
Witness William H. Smagula
DO NOT REMOVE FROM FILE

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-04
Dated: 08/31/2012
Q-TC-017

Witness: William H. Smagula
Request from: TransCanada

Question:
Please provide a copy of the July 2008 PowerAdvocate report for PSNH referenced on page 2 of attachment WHS-3.

Response:
Attached is the requested 2008 PowerAdvocate report.

Long
EXHIBIT NO. 17
9/16/13
S. ROBIDAS

Merrimack Station Clean Air Project
Cost Estimate Analysis

June 17th 2008

~~CONFIDENTIAL~~

PowerAdvocate
Real Results for a Complex World

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Boston, MA 02110
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Clean Air Project Cost Estimate Analysis

Summary

As part of PowerAdvocate's analysis of the Project Cost Estimate for Merrimack Station's Clean Air Project (CAP), site specific factors surrounding the design and construction of the scrubber specific to this installation were scrutinized, along with the market forces associated with capital construction projects in general and retrofit scrubber projects in particular. The objective of this analysis is twofold:

1. Explain why Merrimack Station's CAP's cost estimate is on the high end of the cost per kilowatt range for a complete FGD retrofit relative to similar FGD retrofit projects.
2. Discuss market forces behind capital construction project cost increases in the utility industry, including retrofit scrubber projects, to better understand why Merrimack Station's CAP cost estimate has increased from an estimated $250M in 2006 to an excess of $350M today.

I. Site Specific Factors

It should be clearly noted that the majority of FGD projects, for sulfur and mercury scrubbers alike, exhibit substantial economies of scale once the absorber size reaches approximately 550MW. The costs for the majority of a project, both in procurement and construction, increase exponentially for scrubber capacities that are less than this benchmark. It is not uncommon to find a per-kilowatt cost for a 200MW absorber to be over twice the price of a 600MW unit.

Based on the most recent estimate provided by URS (Estimate), the direct cost per kilowatt for the installed Wet FGD (WFGD) is approximately $775 based upon a nominal station capacity of 458MW. Since this cost is above industry benchmarks, PowerAdvocate analyzed different reasons for the discrepancy and created adjustment factors to bring the scope of Merrimack's CAP more in line with other similar projects. This approach allowed for a more realistic "apples to apples" comparison. Through this comparison, PA determined that a levelized cost for the CAP is approximately $580/kW, or a 25% reduction from per-kW cost of $775. This adjusted cost is based upon applying assumed Impact percentages (i.e. FGD Impact % = 10%) to the Estimate cost components for each of the site specific components, which were then totaled and subsequently subtracted from the Estimate resulting in the equalized $/kW. This adjusted cost falls within the benchmark range for projects of this size as shown below in Table 2 and Figure 1, where market data indicates that construction costs for wet FGD systems in the US have risen dramatically over the past several years and are currently in the range between $250/kW and $654/kW (median $467/kW) for similar sized systems.

The following table shows factors that were considered.

Site Specific Component	Significant Impact?	Discipline/Subsystem Affected
Mercury Scrubber	Yes	BOP Engineering/FGD
Asymmetrical Units to Single Absorber	Yes	BOP/FGD
Station Site Constraints	Yes	BOP/MH
All-Subcontract Construction Basis	Yes	BOP Construction
Foundations	No	N/A
Limited Highway Access	No	N/A
Pressurized Cyclone Boiler	Yes	BOP Engineering

Table 1: CAP site specific analysis components

Further explanation of the methodology utilized in determining the costs (as shown in the attached *Design Differences* spreadsheet, Appendix 1.1) associated with each factor are described below. This list is not considered all-inclusive. A conservative approach was employed due to other design variations for this system that could not be quantified:

Mercury Scrubber Merrimack's CAP is designed specifically for Mercury (Hg) removal with an added benefit of further reducing SO_2 emissions. Most WFGD scrubbers in use and under construction today are designed primarily for SO_2 capture. The design differences for this type of approach include additional Hg oxidation controls/consideration, increased surface area of absorber bed, and increased contact time with flue gas to allow for full reaction.

Asymmetrical Units Combining Into a Single Scrubber This is the largest design difference between Merrimack Station's absorber and majority of similar sized systems in the industry. Since Unit 2 is over twice the power of Unit 1, the flows and capacities of the duct and induced draft system are different. In addition there are design aspects of balancing unequal flows into the same duct channel that set this project apart from many others.

Station Site Constraints Merrimack Station is located on the Merrimack River in central New Hampshire. The eastern edge of the main plant is located within ±200 feet of the river and there are several railroad spurs cutting North-South across the station's footprint. In addition, the Material Handling design is slated to extend from the coal yard to the North, down the East side of the power block to the absorber building to the Southeast. This will require construction of components for the MH and other systems to occur in the restricted space of the riverbank area directly above a rail spur.

All-Subcontract Construction Basis The CAP will be constructed without any direct hire labor from the EPCm. All aspects of the project will be completed in Contract Packages utilizing a General President's Project Maintenance Agreement (GPPMA) or National Maintenance Agreement (NMA) with primarily local union personnel. This approach simplifies management to a degree but also incurs a significant percentage mark-up to cover each subcontractor's overhead and profit.

Pressurized Cyclone Boiler Both coal combustion units at Merrimack Station are of the pressurized cyclone type. This type of combustor can produce higher temperatures and flows than similar pulverized coal combustors. Due to these operating characteristics, further engineering may be required to ensure proper long-term operation.

Each of these factors contributes to the "uniqueness" of the CAP project when compared to a more standard Wet FGD system. When these attributes are summarized and used to levelize the per-kilowatt cost, Merrimack Station's CAP is more in line with other projects of similar size and scope.

Other FGD Retrofits	Capacity (MW)	Project Cost[1] ($)	$/kW	Number of Units[2]	In Service Year
Project 1	600	$150,000,000	$250	1	2009
Project 2	557	$148,000,000	$266	1	2008
Project 3	446	$141,400,000	$317	1	2009
Project 4	364	$121,600,000	$334	1	2010
Project 5	556	$188,000,000	$338	1	2008
Project 6	556	$189,000,000	$340	1	2008
Project 7	576	$218,900,000	$380	1	2009
Project 8	305	$127,900,000	$419	1	2009
Project 9	576	$263,800,000	$458	1	2009
Project 10	390	$185,600,000	$476	1	2009
Project 11	416	$198,000,000	$476	1	2009
Project 12	550	$261,700,000	$476	1	2009
Project 13	571	$280,400,000	$491	1	2009
Project 14	363	$209,800,000	$578	1	2009
Project 15	405	$234,100,000	$578	1	2009
Project 16	320	$195,100,000	$610	1	2009
Project 17	500	$304,900,000	$610	1	2009
Project 18	350	$228,900,000	$654	1	2010
Merrimack Station	**458**	**$354,931,538**	**$775**	**2**	**2012**

Table 2. Projected Completion Costs by $/kW

1. Different retrofit FGD projects may have different components (i.e. PJFF, SCR, PAC, ESPs) included or omitted affecting the final cost. There are other inputs to project costs including geological and bathymetric factors as well as site-specific requirements such as the length of the material handling system or pier work. In addition, Owner's Costs have also been excluded from this price.
2. Number of combustion units serving a single absorber.

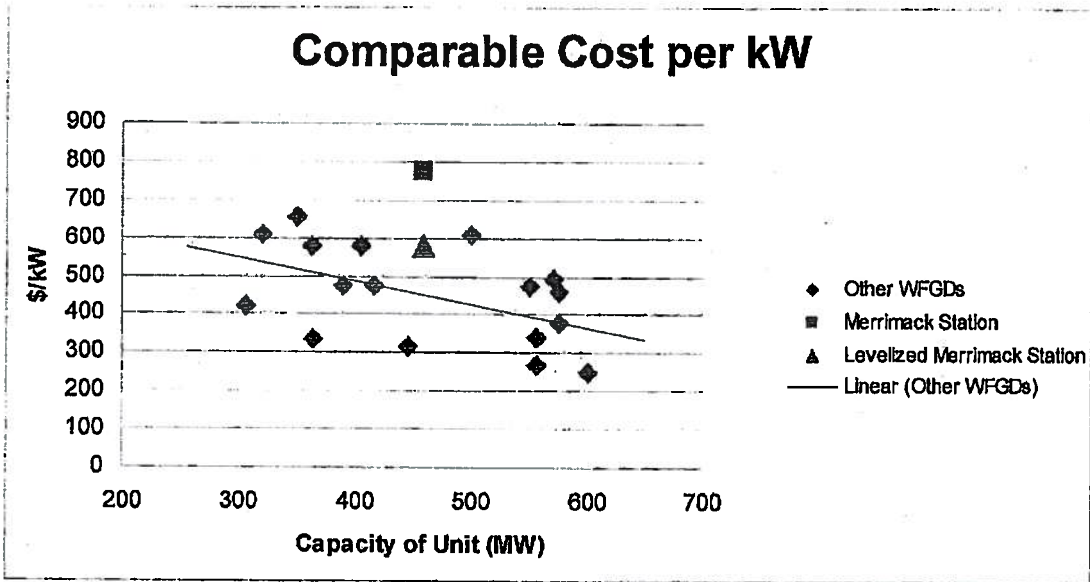

Figure 1. Levelized Cost for Projects of Comparable Size

II. Capital Construction Project Market Trends[1]

Capital construction costs for new generation and transmission projects remain at historic levels with no clear understanding of whether or not we have reached the peak due to the recent volatility of costs associated with the supply market. This fact coupled with the increased uncertainty around projected carbon regulations and the effects of a tight labor market, the utility industry finds itself in a period of time where there seems to be no good indicator for investment decisions. Costs have, in many cases, escalated more than 75% since the year 2000, and ongoing pressure from global players such as China, India, and the Middle East may only accelerate that escalation.

Capital construction costs for retrofit scrubber projects have increased by a modest 7.8% within the last year, with only a 1.0% increase occurring between the third and fourth quarters of 2007. Although the Construction Labor (78% increase since 2000) and Engineering & Project Management (44% increase since 2000) categories combine to encompass approximately 47% of the total retrofit costs, the cost driver behind the large project increase is the Absorber (FGD Island), which has seen a 217% increase over the same period. The demand for absorbers has increased dramatically over the last few years as utilities perform retrofit projects to meet ongoing regulatory standards have to compete with the increase in new coal plants domestically and internationally. Given this, PowerAdvocate forecasts an average increase of 6.2% per year for the next five years for retrofit scrubber project costs, which is slightly down from the 9.5% annualized historical escalation rate over the past eight years.

As shown below in Table 3 and Figure 2, when this escalation forecast factor is applied to the other FGD retrofits with earlier in service dates (2008 thru 2010), the Adjusted Project Costs ($) and Adjusted $/kW increase thus increasing the median $/kW to be more in line with Merrimack Station's $580/kW. Prior to the escalation adjustment, the comparable projects ranged between $250/kW and $654/kW (median $467/kW); following the escalation adjustment, the comparable projects ranged between $299/kW and $738/kW (median $570/kW), a 22% increase. This escalation adjustment further explains why Merrimack Station's GAP's cost estimate is on the on the high end of the cost per kilowatt range for a complete FGD retrofit relative to similar FGD retrofit projects when you consider both the uniqueness factors and the forecast cost escalation associated with retrofit scrubber project costs.

[1] PowerAdvocate PADatasource Market Report, Construction Cost Indices for the US Power Market, Spring 2008

Other FGD Retrofits	Capacity (MW)	Project Cost ($)	$/kW	Number of Units	In Service Year	Adjusted Project Cost ($)[1]	Adjusted $/kW[2]
Project 1	600	$150,000,000	$250	1	2009	$179,665,549	$299
Project 2	557	$148,000,000	$266	1	2008	$188,260,749	$338
Project 3	446	$141,400,000	$317	1	2009	$169,364,724	$380
Project 4	364	$121,600,000	$334	1	2010	$137,145,830	$377
Project 5	556	$188,000,000	$338	1	2008	$239,142,033	$430
Project 6	556	$189,000,000	$340	1	2008	$240,414,065	$432
Project 7	576	$218,900,000	$380	1	2009	$262,191,925	$455
Project 8	305	$127,900,000	$419	1	2009	$153,194,825	$502
Project 9	576	$263,800,000	$458	1	2009	$315,971,813	$549
Project 10	390	$185,600,000	$476	1	2009	$222,306,173	$570
Project 11	416	$198,000,000	$476	1	2009	$237,158,525	$570
Project 12	550	$261,700,000	$476	1	2009	$313,456,495	$570
Project 13	571	$280,400,000	$491	1	2009	$335,854,800	$588
Project 14	363	$209,800,000	$578	1	2009	$251,292,215	$692
Project 15	405	$234,100,000	$578	1	2009	$280,398,034	$692
Project 16	320	$195,100,000	$610	1	2009	$233,684,991	$730
Project 17	500	$304,900,000	$610	1	2009	$365,200,173	$730
Project 18	350	$228,900,000	$654	1	2010	$258,163,492	$738
Merrimack Station	**458**	**$354,931,538**	**$775**	2	2012	$354,931,538	$775

Table 3. Adjusted Projected Completion Costs by $/kW

1. Project cost in 2012 dollars (Merrimack Station in service year) assuming 6.2% escalation in prices per year
2. $/kW in 2012 dollars

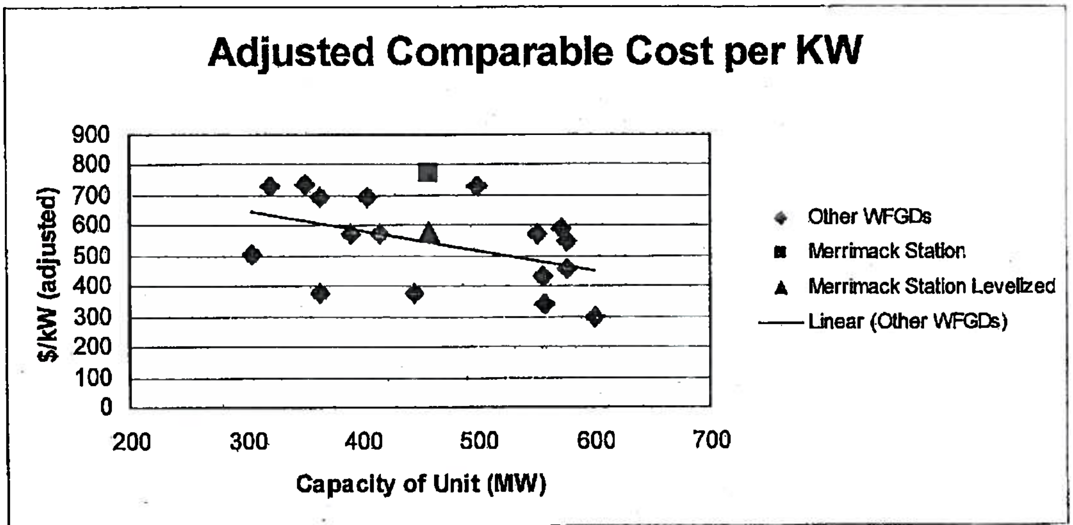

Figure 2. Levelized Cost for Projects of Comparable Size

Appendix 1.1 - Merrimack Station Design Differences from a Standard WFGD for SO_2 Removal

DESIGN DIFFERENCE	COST IMPACT?	URS ENGINEERING IMPACT %	BOP[1] IMPACT %	FGD IMPACT %	MH IMPACT %	COMMENTS
WFGD scrubber for Hg vs SO_2	Y	0%	5%	10%	0%	Additional absorber engineering and construction needs
Asymmetrical Boilers Feeding Single Absorber	Y	10%	8.5%	5%	0%	More complex duct and flow design/two units into one absorber
Station Site Constraints	Y	5%	5%	0%	10%	Construction over railroad, confined area for MH
All Subcontract Construction Basis	Y	0%	3.9%	0%	0%	Remove 21% markup from applicable estimate items[2]
Foundations	N	0%	0%	0%	0%	Foundations appear to be of relatively typical design
Limited Highway Access	N	0%	0%	0%	0%	Interstate 93 is relatively close via small secondary roads
Pressurized Cyclone Boiler	Y	5%	0%	0%	0%	Increased flow and temperature considerations
Totals=		20%	22.40%	15%	10%	
Cost Adjustment=		$4,256,960.20	$35,664,755.62	$15,008,229.00	$4,482,875.00	
New Totals=		$17,027,840.80	$123,552,903.38	$85,046,631.00	$40,345,875.00	
Equalized $/kW=		$580.73				

1= BOP value is made up of direct BOP costs excluding home office engineering.
2= The BOP estimate was analyzed for URS's 21% subcontract markup factor. This markup ($8.3M) was removed from applicable items and the percentage factor calculated based on the actual costs.

For this analysis the following values are assumed:

HO ENG=	$21,284,801	Engineering + eng escalation
BOP=	$159,217,659	BOP + (escalation - eng escalation)
FGD=	$100,054,860	
MH=	$44,828,750	
Total=	$354,931,538	

ORIGINAL
N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-8
Witness William H. Smagula
DO NOT REMOVE FROM FILE

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-0
Dated: 06/04/2012
Q-TC-002-SP01

Witness: Frederick White, Jody J. TenBrock, Terrance J. Large
Request from: TransCanada

Question:
(Originally numbered TC-01, Q-TC-002 in the Temporary Rates portion of this docket) Please provide all fuel price forecasts available to PSNH at the time of its initial decision to construct the flue gas scrubber at Merrimack Station.

Response:
ORIGINAL RESPONSE: PSNH objects to this question as it is based upon a faulty premise. Moreover, the information requested is irrelevant to the subject of this proceeding. Notwithstanding this objection, PSNH responds as follows:

See the response to TC-01, Q-TC-001.

SUPPLEMENTAL RESPONSE: The initial round of contracts for construction of the scrubber were signed in October, 2008. The fuel price forecasts available to PSNH at that time are provided in the attached; which includes NYMEX (natural gas) and broker (coal) forward fuel price quotations from June, 2008, and fuel price forecasts (various) received from industry consultants in February, March, July, and August, 2008. In the scrubber analyses prepared by PSNH, in advance of October, 2008, the company examined a range of values for various cost items, including fuel prices, and did not rely on a singular fuel price forecast.

Long
EXHIBIT NO. 8
4/16/13
S. ROBIDAS

NYMEX Closing Prices - June 11, 2008

$/MMBtu

Year	Natural Gas at Henry Hub	Transportation Basis from Henry Hub	
		Transco Zone 6	Tetco M-3
2008 (Jul-Dec)	12.909	1.714	1.216
2009	11.718	2.178	1.393
2010	10.596	1.919	1.325
2011	10.278	1.801	1.233
2012	10.342	1.700	1.150
2013	10.548		
2014	10.767		
2015	10.992		
2016	11.223		
2017	11.459		

ICAP.
ICAP United, Inc - Coal

10-Jun-08

www.uplcoal.com
Dan Vaughn @ 417-336-5582

www.icapenergy.com
Ian Tapsall, Manzar Iqbal @ 203-752-8493

Matt Keck @ 502-327-1417

Nymex look-alike

Delivery	Bid - Ask Range		Last	Date
Jul	107.50	108.50	*110.00*	10-Jun
Aug	107.50	108.50	*107.75*	06-Jun
Q3 08	107.50	108.50	*110.00*	10-Jun
Q4 08	109.00	110.00	*110.25*	10-Jun
Q1 09	110.25	111.25	*111.00*	06-Jun
Q2 09	110.25	111.25	*110.75*	06-Jun
Q3 09	110.50	111.50	*112.20*	09-Jun
Q4 09	110.50	111.50	*112.50*	09-Jun
Q1 10	109.75	110.75		
CY 09	110.38	111.38	*111.00*	06-Jun
CY 10	109.25	110.25	*105.50*	05-Jun
CY 11	108.25	109.25	*esl*	

CSX-BSK < 1% physical market

Bid - Ask Range		Last	Date
124.50	128.50	*120.00*	04-Jun
123.50	124.50		
123.50	124.50	*124.00 esl*	10-Jun
119.50	120.50	*122.00 fin*	09-Jun
116.50	117.50	*114.00 fin*	06-Jun
115.00	116.00		
114.00	115.00		
113.50	114.50	*83.75 esl*	28-Feb
112.75	113.75		
114.75	115.75	*115.00 esl*	10-Jun
112.50	113.50	*108.50 fin*	29-May
108.00	109.00	*esl*	

PRB 8800 - physical market

Bid - Ask Range		Last	Date
11.25	12.25	*12.00*	04-Jun
11.25	12.25		
11.25	12.25	*11.75 fin*	10-Jun
13.00	14.00	*13.50 esl*	10-Jun
15.60	16.10		
16.80	17.30		
17.80	18.30		
18.80	19.30		
19.15	19.65		
17.25	17.75	*17.50*	09-Jun
19.65	20.15	*20.45*	27-May
20.15	20.65	*19.75*	03-Jun

Other Markets - Most Recent Trades

Delivery	Origin	Btu	#SO2	Last	Date
Jul	CSX	12500	1.2	*118.00*	05-Jun
Aug-Sep	NS	12500	1.2	*140.00*	06-Jun
Q3Q4	NS	12500	1.8	*121.00*	22-May
CY 09	NS	12500	1.6	*102.00*	06-May
Q1 09	NAPP rc	13000	3.0	*103.00*	15-May
CY 10	NAPP rc	13000	3.0	*103.00*	21-May
May-Aug	Mon Rvr	13000	4.8 / 5.0	*97.50*	22-Apr
May-Jul	ILB bg	11500	3.5	*74.00*	15-May
CY 09	PRB xCC	8400	0.8	*13.70*	09-Jun

SO2	Bid	Ask
2008	320	330
2009	319	329
2010	177	182
2011	167	173

Seasonal NOx

Bank	600	675
2008	750	775
2009	600	675
2010	550	700

Annual NOx

2009	4500	5000
2010	2100	2600
2011	1850	2350

SO2
2008 trades 11x, 315 -330

The Daily Scoreboard

Nymex
Jun-Jul trades 110
Q3 trades 110
Q4 trades 112 (10), 111 (2x), 110.25

CSX fin / Nym
CY 09 trades 4.25

CSX 1% phys
Aug-Sep over Oct-Nov trades 4.00
PRB 8800 fin
Q4 / Q3 trades 1.75
CY 09 17.50 (10k), 17.75 (10k), 17.50 (10k)

Additional Market Activity

Delivery	Origin	Btu	#SO2	Bid	Ask

Vaughn's View of the U.S. Coal Markets - a perspective provided by Dan Vaughn to assist in marking coals to market

10-Jun-08

PRB Coal

Origin	Btu	#SO2	Prompt Jul	PM + 1 Aug	PQ Q3 08	PQ + 1 Q4 08	PQ + 2 Q1 00	PQ + 3 Q2 09	PQ + 4 Q3 09	PY CY 09	PY + 1 CY 10	PY + 2 CY 11
BNSF / UP	8800	0.8	11.75	11.75	11.75	13.50	#REFI	#REFI	#REFI	17.50	19.90	20.40
BNSF / UP	8400	0.8	10.00	10.15	10.15	10.50	#REFI	#REFI	#REFI	13.40	15.50	16.00

CAPP Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
BS Rvr	12000	1.2	111.67	111.50	111.50	113.00	114.25	114.25	114.50	114.38	112.75	111.75
Nymex	12000	1.7	108.00	108.00	108.00	109.50	110.75	110.75	111.00	110.88	109.75	108.75
BS Rvr	11500	1.8	101.75	102.00	102.00	103.50	105.00	105.00	105.25	105.13	104.50	103.75
CSX-BSK	12500	1.2	128.35	126.75	126.75	122.75	120.00	118.50	117.50	118.25	110.00	111.50
CSX-BSK	12500	1.8	125.50	124.00	124.00	120.00	117.00	115.50	114.50	115.25	113.00	108.50
NS-T/K	12500	1.2	145.00	142.50	142.50	141.50	131.50	130.00	120.00	120.75	128.00	120.00
NS-T/K	12500	1.8	127.00	128.50	126.50	125.50	122.50	121.00	120.00	120.75	118.50	114.00

NAPP Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
MGA	13000	3.0 / 3.4	107.00	107.00	107.00	107.00	106.00	105.00	105.00	105.25	103.00	98.50
MGA	13000	4.0 / 4.5	100.25	100.50	100.50	100.50	90.50	98.50	98.50	98.75	96.50	92.00
Mon Rvr	13000	4.5 - 5.0	102.50	102.50	102.50	102.50	101.50	100.50	100.50	100.75	98.50	94.00
U. OH Rvr	12200	6.6	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.75

ILB Barge Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
L. OH Rvr	12000	2.0	84.00	84.00	84.00	84.00	83.00	83.00	83.00	83.00	83.00	83.00
L. OH Rvr	12000	5.0	74.00	74.00	74.00	74.00	73.00	73.00	73.00	73.00	73.00	73.00

Colorado Coal

Origin	Btu	#SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
UP	11800	1.0	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00
UP	11300	1.0	63.00	63.00	63.00	63.00	63.00	63.00	63.00	63.00	63.00	63.00

International API Markets ($/tonne)

Origin	kCal	# SO2	Jul	Aug	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	CY 09	CY 10	CY 11
API 2	6000	1.7	176.00	176.00	176.00	176.00	174.00	170.25	166.25	169.00	168.00	163.25
API 4	6000	1.7	137.00	138.25	139.00	140.00	140.50	140.50	140.50	140.50	140.50	141.75

PETROLEUM PRODUCT PRICES FORECAST
No. 2 Fuel Oil (0.2% Sulfur)
$/MMBtu (Connecticut)

Year	Current $				Percent Change			
	Residential	Commercial	Industrial	Electric	Residential	Commercial	Industrial	Electric
1970	$1.48	$1.09	$0.73	$0.37				
1971	$1.56	$1.16	$0.77	$0.54	5.4%	6.4%	5.5%	45.9%
1972	$1.56	$1.16	$0.77	$0.91	0.0%	0.0%	0.0%	68.5%
1973	$1.77	$1.38	$0.99	$1.29	13.5%	19.0%	28.6%	41.8%
1974	$2.88	$2.46	$2.24	$2.28	62.7%	78.3%	126.3%	76.7%
1975	$2.84	$2.44	$2.41	$2.36	-1.4%	-0.8%	7.6%	3.5%
1976	$3.04	$2.62	$2.52	$2.40	7.0%	7.4%	4.6%	1.7%
1977	$3.40	$2.96	$2.78	$2.38	11.8%	13.0%	10.3%	-0.8%
1978	$3.61	$3.12	$2.88	$2.00	6.2%	5.4%	3.6%	-16.0%
1979	$5.19	$4.59	$4.01	$3.64	43.8%	47.1%	39.2%	82.0%
1980	$7.07	$6.37	$5.75	$6.13	36.2%	38.8%	43.4%	68.4%
1981	$8.77	$8.04	$6.93	$7.78	24.0%	26.2%	20.5%	26.9%
1982	$8.53	$7.80	$7.74	$7.31	-2.7%	-3.0%	11.7%	-6.0%
1983	$8.46	$7.46	$7.42	$6.28	-0.8%	-4.4%	-4.1%	-14.1%
1984	$8.69	$7.41	$6.95	$6.21	2.7%	-0.7%	-6.3%	-1.1%
1985	$8.37	$7.07	$6.75	$5.88	-3.7%	-4.6%	-2.9%	-5.3%
1986	$6.90	$4.97	$4.43	$3.59	-17.6%	-29.7%	-34.4%	-38.9%
1987	$6.46	$4.88	$4.88	$4.01	-6.4%	-1.8%	10.2%	11.7%
1988	$6.61	$4.65	$4.67	$3.64	2.3%	-4.7%	-4.3%	-9.2%
1989	$7.23	$5.51	$5.54	$4.26	9.4%	18.5%	18.6%	17.0%
1990	$8.55	$6.80	$6.77	$5.67	18.3%	23.4%	22.2%	33.1%
1991	$8.27	$6.09	$5.93	$4.92	-3.3%	-10.4%	-12.4%	-13.2%
1992	$7.24	$5.45	$5.11	$4.82	-12.5%	-10.5%	-13.8%	-2.0%
1993	$7.02	$5.22	$5.06	$4.12	-3.0%	-4.2%	-1.0%	-14.5%
1994	$6.80	$5.01	$4.78	$3.82	-3.1%	-4.0%	-5.5%	-7.3%
1995	$6.60	$4.94	$4.77	$3.82	-2.9%	-1.4%	-0.2%	0.0%
1996	$7.54	$5.77	$5.91	$4.76	14.2%	16.8%	23.9%	24.6%
1997	$7.36	$5.54	$5.49	$4.88	-2.4%	-4.0%	-7.1%	2.5%
1998	$6.35	$4.48	$4.52	$3.28	-13.7%	-19.1%	-17.7%	-32.8%
1999	$6.51	$4.86	$4.86	$4.03	2.5%	8.5%	7.5%	22.9%
2000	$9.87	$7.73	$7.71	$6.81	51.6%	59.1%	58.6%	69.0%
2001	$9.47	$7.32	$6.69	$5.79	-4.1%	-5.3%	-13.2%	-15.0%
2002	$8.54	$6.87	$6.31	$5.29	-9.8%	-6.1%	-5.7%	-8.6%
2003	$10.36	$8.12	$7.58	$6.85	21.3%	18.2%	20.1%	29.5%
2004	$11.60	$9.87	$9.58	$6.43	12.0%	21.6%	26.4%	-6.1%
2005	$15.80	$13.64	$13.25	$12.29	36.2%	38.2%	38.3%	91.2%
2006	$17.20	$14.99	$14.60	$13.62	8.9%	10.0%	10.2%	10.8%
2007	$18.93	$16.68	$16.28	$15.28	10.0%	11.2%	11.5%	12.2%
2008	$22.22	$19.93	$19.53	$18.51	17.4%	19.5%	20.0%	21.2%
2009	$21.66	$19.34	$18.93	$17.90	-2.5%	-3.0%	-3.1%	-3.3%
2010	$21.50	$19.14	$18.72	$17.68	-0.8%	-1.0%	-1.1%	-1.2%
2011	$21.77	$19.38	$18.96	$17.90	1.3%	1.3%	1.3%	1.2%
2012	$22.37	$19.95	$19.52	$18.45	2.8%	2.9%	3.0%	3.1%
2013	$22.98	$20.53	$20.09	$19.00	2.7%	2.9%	2.9%	3.0%
2014	$23.60	$21.12	$20.68	$19.57	2.7%	2.9%	2.9%	3.0%
2015	$24.24	$21.73	$21.28	$20.16	2.7%	2.9%	2.9%	3.0%
2016	$24.89	$22.34	$21.89	$20.75	2.7%	2.8%	2.9%	2.9%
2017	$25.82	$23.24	$22.78	$21.63	3.7%	4.0%	4.1%	4.2%
2018	$26.79	$24.17	$23.71	$22.54	3.8%	4.0%	4.1%	4.2%

Note: 1989-1998 data was updated using the latest figures from the Master Oil and Gas Database
Basis differences for 1989-1995 were taken from actual data

PETROLEUM PRODUCT PRICES FORECAST
Residual Fuel Oil (1.0% Sulfur) - Annual
$/MMBtu (Connecticut)

Year	Current $			Percent Change		
	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1970	$0.42	$0.43	$0.38			
1971	$0.59	$0.61	$0.54	40.5%	41.9%	42.1%
1972	$0.70	$0.66	$0.65	18.6%	8.2%	20.4%
1973	$0.83	$0.79	$0.85	18.6%	19.7%	30.8%
1974	$2.00	$2.02	$2.06	141.0%	155.7%	142.4%
1975	$1.97	$2.12	$2.02	-1.5%	5.0%	-1.9%
1976	$1.87	$2.08	$1.94	-5.1%	-1.9%	-4.0%
1977	$2.22	$2.31	$2.24	18.7%	11.1%	15.5%
1978	$2.11	$2.34	$2.13	-5.0%	1.3%	-4.9%
1979	$3.35	$3.41	$3.32	58.8%	45.7%	55.9%
1980	$4.59	$4.55	$4.70	37.0%	33.4%	41.6%
1981	$5.49	$5.74	$5.56	19.6%	26.2%	18.3%
1982	$4.67	$4.88	$4.75	-14.9%	-15.0%	-14.6%
1983	$4.51	$4.67	$4.54	-3.4%	-4.3%	-4.4%
1984	$5.25	$5.25	$4.84	16.4%	12.4%	6.6%
1985	$4.68	$4.68	$4.24	-10.9%	-10.9%	-12.4%
1986	$2.79	$2.79	$2.51	-40.4%	-40.4%	-40.8%
1987	$3.12	$3.12	$2.93	11.8%	11.8%	16.7%
1988	$2.57	$2.57	$2.40	-17.6%	-17.6%	-18.1%
1989	$3.04	$3.04	$2.85	18.3%	18.3%	18.8%
1990	$3.25	$3.25	$3.01	6.9%	6.9%	5.6%
1991	$2.69	$2.69	$2.47	-17.2%	-17.2%	-17.9%
1992	$2.53	$2.53	$2.40	-5.9%	-5.9%	-2.8%
1993	$2.66	$2.66	$2.39	5.1%	5.1%	-0.4%
1994	$3.16	$3.16	$2.52	18.8%	18.8%	5.4%
1995	$3.38	$3.38	$2.63	7.0%	7.0%	4.4%
1996	$3.90	$3.90	$3.21	15.4%	15.4%	22.1%
1997	$3.15	$3.15	$2.92	-19.2%	-19.2%	-9.0%
1998	$2.46	$2.46	$2.18	-21.9%	-21.9%	-25.3%
1999	$2.55	$2.55	$2.23	3.7%	3.7%	2.3%
2000	$4.36	$4.36	$3.27	71.0%	71.0%	–
2001	$4.04	$4.04	$3.37	-7.3%	-7.3%	–
2002	$4.67	$4.67	$3.67	15.6%	15.6%	8.9%
2003	$5.40	$5.40	$3.74	15.6%	15.6%	1.9%
2004	$5.64	$5.64	$3.96	4.4%	4.4%	5.9%
2005	$7.42	$7.42	$6.62	31.5%	31.5%	67.3%
2006	$8.31	$8.31	$7.60	12.1%	12.1%	13.2%
2007	$9.47	$9.47	$8.64	13.9%	13.9%	15.2%
2008	$11.41	$11.41	$10.57	20.5%	20.5%	22.3%
2009	$10.94	$10.94	$10.09	-4.1%	-4.1%	-4.5%
2010	$10.71	$10.71	$9.85	-2.1%	-2.1%	-2.4%
2011	$11.26	$11.26	$10.38	5.1%	5.1%	5.4%
2012	$11.59	$11.59	$10.70	3.0%	3.0%	3.1%
2013	$11.93	$11.93	$11.03	2.9%	2.9%	3.1%
2014	$12.28	$12.28	$11.37	2.9%	2.9%	3.0%
2015	$12.63	$12.63	$11.71	2.9%	2.9%	3.0%
2016	$12.99	$12.99	$12.06	2.9%	2.9%	3.0%
2017	$13.52	$13.52	$12.58	4.1%	4.1%	4.3%
2018	$14.08	$14.08	$13.12	4.1%	4.1%	4.3%

PETROLEUM PRODUCT PRICES FORECAST
Residual Fuel Oil (1.0% Sulfur) - Annual
$/MMBtu (Connecticut)

Year	Current $			Percent Change		
	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1993	$2.66	$2.66	$2.39			
1994	$3.16	$3.16	$2.52	18.8%	18.8%	5.4%
1995	$3.38	$3.38	$2.63	7.0%	7.0%	4.4%
1996	$3.90	$3.90	$3.24	15.4%	15.4%	23.2%
1997	$3.15	$3.15	$2.92	-19.2%	-19.2%	-9.9%
1998	$2.46	$2.46	$2.18	-21.9%	-21.9%	-25.3%
1999	$2.55	$2.55	$2.23	3.7%	3.7%	2.3%
2000	$4.36	$4.36	$3.27	71.0%	71.0%	–
2001	$4.04	$4.04	$3.37	-7.3%	-7.3%	–
2002	$4.67	$4.67	$3.67	15.6%	15.6%	8.9%
2003	$5.40	$5.40	$3.74	15.6%	15.6%	1.9%
2004	$5.64	$5.64	$3.96	4.4%	4.4%	5.9%
2005	$7.42	$7.42	$6.62	31.5%	31.5%	67.3%
2006	$8.31	$8.31	$7.50	12.1%	12.1%	13.2%
2007	$9.47	$9.47	$8.64	13.9%	13.9%	15.2%
2008	$11.41	$11.41	$10.57	20.5%	20.5%	22.3%
2009	$10.94	$10.94	$10.09	-4.1%	-4.1%	-4.5%
2010	$10.71	$10.71	$9.85	-2.1%	-2.1%	-2.4%
2011	$11.26	$11.26	$10.38	5.1%	5.1%	5.4%
2012	$11.59	$11.59	$10.70	3.0%	3.0%	3.1%
2013	$11.93	$11.93	$11.03	2.9%	2.9%	3.1%
2014	$12.28	$12.28	$11.37	2.9%	2.9%	3.0%
2015	$12.63	$12.63	$11.71	2.9%	2.9%	3.0%
2016	$12.99	$12.99	$12.06	2.9%	2.9%	3.0%
2017	$13.52	$13.52	$12.58	4.1%	4.1%	4.3%
2018	$14.08	$14.08	$13.12	4.1%	4.1%	4.3%

PETROLEUM PRODUCT PRICES FORECAST

Residual Fuel Oil (1.0% Sulfur) - Summer

$/MMBtu (Connecticut)

Year	Current $			Percent Change		
	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1993	$2.74	$2.74	$2.47			
1994	$3.12	$3.12	$2.48	14.0%	14.0%	0.5%
1995	$3.35	$3.35	$2.60	7.5%	7.5%	5.0%
1996	$3.78	$3.78	$3.12	12.8%	12.8%	20.0%
1997	$3.06	$3.06	$2.83	-19.1%	-19.1%	-9.4%
1998	$2.53	$2.53	$2.25	-17.5%	-17.5%	-20.7%
1999	$2.72	$2.72	$2.40	7.7%	7.7%	6.8%
2000	$4.47	$4.47	–	64.6%	64.6%	–
2001	$4.01	$4.01	$3.34	-10.4%	-10.4%	–
2002	$4.93	$4.93	$3.93	23.0%	23.0%	17.7%
2003	$5.11	$5.11	$3.45	3.6%	3.6%	-12.3%
2004	$5.74	$5.74	$4.06	12.4%	12.4%	17.7%
2005	$7.76	$7.76	$6.97	35.2%	35.2%	71.6%
2006	$8.43	$8.43	$7.62	8.6%	8.6%	9.3%
2007	$10.60	$10.60	$9.77	25.7%	25.7%	28.2%
2008	$10.95	$10.95	$10.11	3.3%	3.3%	3.5%
2009	$10.60	$10.60	$9.75	-3.2%	-3.2%	-3.6%
2010	$10.50	$10.50	$9.64	-1.0%	-1.0%	-1.2%
2011	$11.03	$11.03	$10.16	5.1%	5.1%	5.4%
2012	$11.71	$11.71	$10.82	6.2%	6.2%	6.6%
2013	$12.05	$12.05	$11.15	2.9%	2.9%	3.0%
2014	$12.40	$12.40	$11.49	2.9%	2.9%	3.0%
2015	$12.75	$12.75	$11.83	2.9%	2.9%	3.0%
2016	$13.12	$13.12	$12.18	2.8%	2.8%	2.9%
2017	$13.64	$13.64	$12.70	4.0%	4.0%	4.2%
2018	$14.20	$14.20	$13.24	4.0%	4.0%	4.2%

PETROLEUM PRODUCT PRICES FORECAST
Residual Fuel Oil (1.0% Sulfur) - Winter
$/MMBtu (Connecticut)

Year	Current $			Percent Change		
	Commercial	Industrial	Electric	Commercial	Industrial	Electric
1993	$2.55	$2.55	$2.28			
1994	$3.22	$3.22	$2.58	26.0%	26.0%	12.9%
1995	$3.42	$3.42	$2.67	6.2%	6.2%	3.5%
1996	$4.06	$4.06	$3.40	18.9%	18.9%	27.6%
1997	$3.27	$3.27	$3.04	-19.4%	-19.4%	-10.5%
1998	$2.37	$2.37	$2.09	-27.7%	-27.7%	-31.4%
1999	$2.31	$2.31	$1.99	-2.3%	-2.3%	-4.5%
2000	$4.20	$4.20	--	81.5%	81.5%	--
2001	$4.08	$4.08	$3.41	-2.8%	-2.8%	--
2002	$4.30	$4.30	$3.30	5.4%	5.4%	-3.2%
2003	$5.80	$5.80	$4.14	34.9%	34.9%	25.5%
2004	$5.50	$5.50	$3.82	-5.3%	-5.3%	-7.9%
2005	$6.91	$6.91	$6.12	25.8%	25.8%	60.4%
2006	$8.14	$8.14	$7.33	17.8%	17.8%	19.8%
2007	$10.67	$10.67	$9.84	31.0%	31.0%	34.2%
2008	$12.05	$12.05	$11.22	13.0%	13.0%	13.8%
2009	$11.42	$11.42	$10.57	-5.3%	-5.3%	-5.8%
2010	$11.01	$11.01	$10.15	-3.6%	-3.6%	-4.0%
2011	$11.57	$11.57	$10.70	5.1%	5.1%	5.4%
2012	$11.42	$11.42	$10.54	-1.3%	-1.3%	-1.5%
2013	$11.76	$11.76	$10.86	3.0%	3.0%	3.1%
2014	$12.11	$12.11	$11.20	2.9%	2.9%	3.1%
2015	$12.46	$12.46	$11.54	2.9%	2.9%	3.1%
2016	$12.83	$12.83	$11.89	2.9%	2.9%	3.0%
2017	$13.36	$13.36	$12.41	4.1%	4.1%	4.3%
2018	$13.91	$13.91	$12.95	4.1%	4.1%	4.3%

DELIVERED NATURAL GAS PRICES FORECAST
$/MMBtu (Connecticut)

Year	Current $				Percent Change			
	Residential	Commercial	Industrial	Electric	Residential	Commercial	Industrial	Electric
1970	$1.88	$1.45	$1.03	$0.34				
1971	$2.04	$1.53	$1.14	$0.38	8.5%	5.5%	10.7%	11.8%
1972	$2.06	$1.59	$1.15	$0.43	1.0%	3.9%	0.9%	13.2%
1973	$2.21	$1.79	$1.24	$0.53	7.3%	12.6%	7.8%	23.3%
1974	$2.76	$2.20	$1.71	$0.63	24.9%	22.9%	37.9%	18.9%
1975	$3.28	$2.64	$2.24	$1.36	18.8%	20.0%	31.0%	115.9%
1976	$3.38	$3.20	$2.65	$1.65	3.0%	21.2%	18.3%	21.3%
1977	$4.30	$3.53	$2.94		27.2%	10.3%	10.9%	
1978	$4.42	$3.72	$3.04		2.8%	5.4%	3.4%	
1979	$4.69	$3.90	$3.25		6.1%	4.8%	6.9%	
1980	$5.72	$4.67	$4.08		22.0%	19.7%	25.5%	
1981	$6.68	$5.46	$4.97		16.8%	16.9%	21.8%	
1982	$8.29	$6.78	$5.86		24.1%	24.2%	17.9%	
1983	$9.43	$7.24	$5.76		13.8%	6.8%	-1.7%	
1984	$8.56	$6.49	$5.47	$3.71	-9.2%	-10.4%	-5.0%	
1985	$8.88	$6.59	$5.38	$3.39	3.7%	1.5%	-1.6%	-8.6%
1986	$8.57	$6.24	$4.53	$2.09	-3.5%	-5.3%	-15.8%	-38.3%
1987	$7.96	$5.59	$4.08	$2.37	-7.1%	-10.4%	-9.9%	13.4%
1988	$7.63	$5.45	$3.92	$2.17	-4.1%	-2.5%	-3.9%	-8.4%
1989	$7.98	$5.88	$4.36	$2.51	4.6%	7.9%	11.2%	15.7%
1990	$8.58	$6.30	$4.80	$2.81	7.5%	7.1%	10.2%	12.0%
1991	$8.74	$6.90	$4.84	$2.16	2.0%	9.6%	0.6%	-23.1%
1992	$8.96	$7.20	$4.92	$2.74	2.5%	4.3%	1.7%	26.9%
1993	$9.16	$6.81	$4.63	$3.79	2.2%	-5.4%	-5.8%	38.2%
1994	$9.84	$7.18	$4.36	$1.93	7.5%	5.3%	-5.9%	-49.0%
1995	$9.70	$7.34	$4.26	$1.95	-1.4%	2.3%	-2.3%	1.0%
1996	$9.79	$7.19	$4.66	$2.68	0.8%	-2.1%	9.4%	37.3%
1997	$10.03	$7.02	$4.59	$2.40	2.5%	-2.4%	-1.4%	-10.5%
1998	$10.29	$6.69	$4.21	$2.37	2.6%	-4.7%	-8.2%	-1.2%
1999	$10.23	$6.34	$4.03	$2.66	-0.6%	-5.2%	-4.4%	12.3%
2000	$11.10	$6.43	$5.78	$3.97	8.4%	1.4%	43.4%	49.4%
2001	$11.84	$7.46	$6.57	$3.09	6.7%	16.0%	13.8%	-22.2%
2002	$10.83	$6.97	$4.83	$3.51	-8.6%	-6.5%	-26.6%	13.4%
2003	$12.40	$10.17	$7.30	$6.20	14.5%	45.8%	51.3%	76.6%
2004	$13.65	$10.98	$9.05	$6.70	10.1%	8.0%	23.9%	8.1%
2005	$15.79	$12.70	$11.36	$9.61	15.6%	15.6%	25.5%	43.5%
2006	$17.10	$13.20	$10.56	$7.30	8.3%	4.0%	-7.0%	-24.0%
2007	$15.20	$11.92	$9.31	$7.77	-11.1%	-9.7%	-11.6%	6.4%
2008	$15.55	$12.23	$9.58	$8.02	2.3%	2.6%	2.9%	3.2%
2009	$15.34	$11.96	$9.28	$7.69	-1.4%	-2.2%	-3.2%	-4.1%
2010	$15.47	$12.05	$9.32	$7.72	0.9%	0.7%	0.5%	0.3%
2011	$15.81	$12.34	$9.58	$7.95	2.2%	2.4%	2.7%	3.0%
2012	$16.43	$12.91	$10.11	$8.46	3.9%	4.6%	5.5%	6.4%
2013	$16.96	$13.39	$10.56	$8.88	3.3%	3.8%	4.4%	5.0%
2014	$17.33	$13.71	$10.84	$9.14	2.2%	2.4%	2.7%	2.9%
2015	$17.71	$14.04	$11.13	$9.41	2.2%	2.4%	2.7%	2.9%
2016	$18.09	$14.38	$11.43	$9.68	2.2%	2.4%	2.7%	2.9%
2017	$18.48	$14.72	$11.73	$9.96	2.1%	2.4%	2.6%	2.9%
2018	$18.88	$15.07	$12.04	$10.25	2.2%	2.4%	2.6%	2.9%

Note: Beginning in 2000, delivered natural gas prices for the electric sector are estimated.

DELIVERED PROPANE PRICES FORECAST
Cents/Gallon (Selkirk)

Winter

Year	Current $	Percent Change
1989	–	
1990	–	
1991	45.3	
1992	39.1	-13.8%
1993	40.2	3.0%
1994	40.8	1.3%
1995	42.6	4.4%
1996	59.8	40.4%
1997	51.8	-13.3%
1998	37.1	-28.4%
1999	40.7	9.6%
2000	72.3	77.8%
2001	61.7	-14.7%
2002	50.3	-18.4%
2003	74.3	47.6%
2004	84.5	13.7%
2005	99.4	17.7%
2006	104.9	5.5%
2007	137.8	31.3%
2008	178.8	29.8%
2009	169.6	-5.1%
2010	152.0	-10.4%
2011	154.6	1.6%
2012	160.6	4.0%
2013	167.0	3.9%
2014	173.4	3.9%
2015	180.0	3.8%
2016	186.7	3.7%
2017	196.7	5.3%
2018	207.1	5.3%

Annual

Year	Current $	Percent Change
1989	–	
1990	–	
1991	42.6	
1992	40.9	-4.1%
1993	40.8	-0.1%
1994	40.6	-0.6%
1995	41.9	3.3%
1996	56.9	35.7%
1997	48.9	-14.0%
1998	36.5	-25.3%
1999	44.2	21.0%
2000	69.1	56.3%
2001	62.3	-9.9%
2002	52.3	-15.9%
2003	74.0	41.3%
2004	95.7	29.4%
2005	100.5	5.0%
2006	109.8	9.3%
2007	137.5	25.2%
2008	176.3	28.3%
2009	168.0	-4.7%
2010	155.9	-7.1%
2011	158.4	1.6%
2012	164.8	4.0%
2013	171.3	3.9%
2014	178.0	3.9%
2015	184.8	3.8%
2016	191.7	3.7%
2017	202.0	5.4%
2018	212.7	5.3%

Summer

Year	Current $	Percent Change
1989	–	
1990	–	
1991	40.7	
1992	42.1	3.6%
1993	41.3	-2.1%
1994	40.5	-1.9%
1995	41.5	2.6%
1996	54.9	32.2%
1997	46.9	-14.6%
1998	36.1	-22.9%
1999	46.7	29.3%
2000	66.7	43.0%
2001	55.0	-17.6%
2002	52.5	-4.5%
2003	64.4	22.6%
2004	85.8	33.2%
2005	101.3	18.0%
2006	113.3	11.9%
2007	137.2	21.1%
2008	174.5	27.1%
2009	166.8	-4.4%
2010	158.8	-4.8%
2011	161.3	1.6%
2012	167.8	4.0%
2013	174.5	4.0%
2014	181.2	3.9%
2015	188.2	3.8%
2016	195.3	3.8%
2017	205.8	5.4%
2018	216.7	5.3%

HENRY HUB NATURAL GAS PRICE FORECAST
$/MMBtu

Year	Current $ Annual	Current $ Summer	Current $ Winter	Percent Change Annual	Percent Change Summer	Percent Change Winter
1989	$1.70	$1.61	$1.82			
1990	$1.70	$1.48	$2.01	0.1%	-8.1%	10.2%
1991	$1.49	$1.39	$1.62	-12.5%	-5.7%	-19.4%
1992	$1.77	$1.87	$1.63	19.2%	34.4%	0.9%
1993	$2.12	$2.16	$2.07	19.7%	15.4%	26.7%
1994	$1.92	$1.78	$2.11	-9.5%	-17.4%	2.0%
1995	$1.69	$1.61	$1.79	-12.2%	-9.7%	-15.1%
1996	$2.76	$2.31	$3.39	63.4%	43.3%	88.7%
1997	$2.53	$2.40	$2.70	-8.4%	4.0%	-20.3%
1998	$2.08	$2.11	$2.05	-17.5%	-12.1%	-24.1%
1999	$2.27	$2.41	$2.06	8.7%	14.3%	0.7%
2000	$4.23	$4.19	$4.28	86.6%	73.9%	107.2%
2001	$4.07	$3.44	$4.96	-3.7%	-18.0%	15.9%
2002	$3.33	$3.40	$3.23	-18.2%	-1.0%	-34.9%
2003	$5.63	$5.17	$6.26	68.9%	51.9%	94.0%
2004	$5.84	$5.83	$5.86	3.9%	12.8%	-6.4%
2005	$8.81	$8.97	$8.59	50.8%	53.7%	46.6%
2006	$6.76	$6.21	$7.54	-23.3%	-30.8%	-12.3%
2007	$6.95	$6.82	$7.12	2.7%	9.9%	-5.5%
2008	$7.17	$6.92	$7.52	3.2%	1.5%	5.5%
2009	$6.83	$6.74	$6.95	-4.8%	-2.6%	-7.6%
2010	$6.84	$6.38	$7.48	0.1%	-6.4%	7.6%
2011	$7.06	$6.59	$7.72	3.2%	3.2%	3.2%
2012	$7.55	$7.05	$8.26	7.0%	7.0%	7.0%
2013	$7.97	$7.44	$8.71	5.5%	5.5%	5.5%
2014	$8.21	$7.67	$8.98	3.1%	3.1%	3.1%
2015	$8.47	$7.90	$9.26	3.1%	3.1%	3.1%
2016	$8.73	$8.15	$9.55	3.1%	3.1%	3.1%
2017	$9.00	$8.40	$9.84	3.1%	3.1%	3.1%
2018	$9.27	$8.65	$10.14	3.1%	3.1%	3.1%

TX-LA ONSHORE WELLHEAD NATURAL GAS PRICE FORECAST
$/MMBtu

Year	Current $			Percent Change		
	Annual	Summer	Winter	Annual	Summer	Winter
1989	$1.63	$1.55	$1.76			
1990	$1.61	$1.42	$1.87	-1.6%	-8.1%	6.5%
1991	$1.39	$1.30	$1.52	-13.3%	-8.2%	-18.8%
1992	$1.65	$1.74	$1.52	18.4%	33.9%	-0.2%
1993	$2.00	$2.04	$1.94	21.2%	17.1%	27.8%
1994	$1.78	$1.68	$1.93	-11.0%	-17.9%	-0.7%
1995	$1.55	$1.49	$1.65	-12.7%	-11.4%	-14.3%
1996	$2.45	$2.13	$2.90	57.6%	43.1%	75.8%
1997	$2.39	$2.27	$2.56	-2.4%	6.9%	-11.9%
1998	$1.98	$2.01	$1.94	-17.0%	-11.4%	-24.0%
1999	$2.15	$2.30	$1.94	8.3%	14.1%	0.0%
2000	$4.09	$4.05	$4.13	90.1%	76.5%	112.8%
2001	$3.93	$3.32	$4.78	-3.8%	-18.0%	15.6%
2002	$3.21	$3.28	$3.10	-18.4%	-1.1%	-35.2%
2003	$5.39	$5.00	$5.92	68.0%	52.4%	91.2%
2004	$5.72	$5.66	$5.80	6.1%	13.1%	-2.1%
2005	$8.25	$8.56	$7.82	44.4%	51.3%	34.9%
2006	$6.48	$6.05	$7.10	-21.4%	-29.4%	-9.2%
2007	$6.69	$6.63	$6.78	3.2%	9.6%	-4.5%
2008	$6.90	$6.65	$7.25	3.2%	0.4%	7.0%
2009	$6.56	$6.47	$6.68	-4.9%	-2.7%	-7.8%
2010	$6.57	$6.11	$7.21	0.1%	-5.6%	7.9%
2011	$6.79	$6.32	$7.45	3.4%	3.4%	3.4%
2012	$7.28	$6.78	$7.99	7.3%	7.3%	7.3%
2013	$7.82	$7.68	$8.11	7.4%	13.3%	1.5%
2014	$8.07	$7.93	$8.36	3.1%	3.2%	3.1%
2015	$8.32	$8.18	$8.61	3.1%	3.2%	3.1%
2016	$8.58	$8.44	$8.88	3.1%	3.1%	3.0%
2017	$8.84	$8.70	$9.14	3.1%	3.1%	3.0%
2018	$9.12	$8.97	$9.42	3.1%	3.1%	3.0%

LA GULF COAST ONSHORE GAS PRICE FORECAST
$/MMBtu

Year	Current $			Percent Change		
	Annual	Summer	Winter	Annual	Summer	Winter
1989	$1.69	$1.60	$1.81			
1990	$1.69	$1.48	$1.98	0.0%	-7.5%	9.4%
1991	$1.48	$1.37	$1.62	-12.4%	-7.1%	-17.9%
1992	$1.74	$1.86	$1.57	17.8%	35.8%	-3.6%
1993	$2.10	$2.16	$2.02	20.8%	15.9%	29.0%
1994	$1.89	$1.77	$2.06	-10.2%	-18.2%	1.8%
1995	$1.60	$1.54	$1.69	-15.1%	-13.0%	-17.6%
1996	$2.62	$2.18	$3.25	63.7%	41.5%	91.9%
1997	$2.45	$2.31	$2.65	-6.6%	6.2%	-18.6%
1998	$2.04	$2.05	$2.02	-16.8%	-11.1%	-23.7%
1999	$2.21	$2.34	$2.02	8.3%	14.1%	0.0%
2000	$4.16	$4.12	$4.22	88.6%	75.8%	109.3%
2001	$3.98	$3.37	$4.85	-4.3%	-18.3%	14.8%
2002	$3.26	$3.33	$3.16	-18.2%	-1.2%	-34.8%
2003	$5.39	$5.04	$5.88	65.5%	51.5%	86.0%
2004	$5.69	$5.56	$5.86	5.5%	10.4%	-0.4%
2005	$8.63	$8.92	$8.23	51.8%	60.3%	40.4%
2006	$6.72	$6.26	$7.35	-22.2%	-29.8%	-10.7%
2007	$6.94	$6.79	$7.16	3.4%	8.4%	-2.6%
2008	$7.12	$6.87	$7.47	2.5%	1.2%	4.3%
2009	$6.78	$6.69	$6.90	-4.8%	-2.6%	-7.6%
2010	$6.79	$6.33	$7.43	0.1%	-5.4%	7.6%
2011	$7.01	$6.54	$7.67	3.3%	3.3%	3.3%
2012	$7.50	$7.00	$8.21	7.1%	7.1%	7.1%
2013	$7.84	$7.76	$7.83	4.5%	10.8%	-4.6%
2014	$8.09	$8.00	$8.08	3.1%	3.1%	3.1%
2015	$8.34	$8.25	$8.33	3.1%	3.2%	3.1%
2016	$8.60	$8.51	$8.59	3.1%	3.1%	3.1%
2017	$8.87	$8.77	$8.86	3.1%	3.1%	3.1%
2018	$9.14	$9.05	$9.13	3.1%	3.1%	3.1%

Boston City Gate Natural Gas Price
$/MMBtu

Year	Current $			Percent Change		
	Annual	Summer	Winter	Annual	Summer	Winter
1992	$2.28	$2.30	$2.26			
1993	$2.57	$2.53	$2.64	12.8%	10.1%	16.6%
1994	$2.44	$2.10	$2.92	-5.3%	-17.2%	10.7%
1995	$2.25	$1.89	$2.76	-7.5%	-9.8%	-5.3%
1996	$3.60	$2.60	$4.99	59.6%	37.5%	80.8%
1997	$2.94	$2.72	$3.25	-18.4%	4.4%	-35.0%
1998	$2.42	$2.37	$2.48	-17.7%	-12.7%	-23.6%
1999	$2.57	$2.64	$2.48	6.3%	11.2%	-0.2%
2000	$5.18	$4.50	$6.13	101.6%	70.7%	147.7%
2001	$4.42	$3.78	$5.32	-14.6%	-16.0%	-13.2%
2002	$3.52	$3.52	$3.52	-20.4%	-6.8%	-33.8%
2003	$6.35	$5.41	$7.01	80.2%	53.6%	98.9%
2004	$7.29	$6.35	$8.60	14.8%	17.4%	22.7%
2005	$9.85	$9.13	$10.87	35.3%	43.7%	26.5%
2006	$8.23	$6.88	$10.11	-16.5%	-24.6%	-7.0%
2007	$7.88	$7.43	$8.52	-4.2%	7.9%	-15.8%
2008	$8.37	$7.56	$9.50	6.2%	1.8%	11.5%
2009	$8.81	$8.72	$8.93	5.3%	15.4%	-6.0%
2010	$8.82	$8.36	$9.46	0.1%	-4.1%	5.9%
2011	$9.04	$8.57	$9.70	2.5%	2.5%	2.6%
2012	$9.53	$9.03	$10.24	5.5%	5.4%	5.6%
2013	$8.97	$8.07	$10.69	-5.9%	-10.6%	4.4%
2014	$9.24	$8.30	$10.96	2.9%	2.9%	2.5%
2015	$9.50	$8.54	$11.24	2.9%	2.9%	2.5%
2016	$9.78	$8.79	$11.53	2.9%	2.8%	2.5%
2017	$10.06	$9.04	$11.82	2.9%	2.8%	2.5%
2018	$10.35	$9.29	$12.12	2.9%	2.8%	2.5%

QCF (QUARTERLY COAL FORECST) - 200803
JD Energy, Inc.
BASE CASE
March 2008

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON
ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON
QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia																				
-1.6%, 13000 BTU	$26.58	$28.41	$24.85	$24.45	$26.34	$26.04	$24.94	$23.65	$24.09	$40.52	$30.87	$31.04	$50.27	$54.42	$45.82	$46.61	$78.98	$50.48	$41.14	$37.42
-1.8%, 13000 BTU	$25.06	$26.58	$23.49	$22.21	$22.51	$22.89	$23.59	$22.12	$23.07	$39.46	$29.38	$29.83	$49.89	$52.23	$43.41	$45.85	$77.43	$49.13	$40.29	$38.70
-2.3%, 13000 BTU	$22.40	$21.72	$21.48	$20.71	$21.26	$21.79	$22.84	$20.65	$22.05	$35.99	$27.51	$28.67	$47.91	$48.94	$39.80	$44.71	$75.10	$47.10	$39.00	$35.63
Central Appalachia																				
-.7%, 12500 BTU	$24.31	$26.02	$26.75	$24.88	$28.01	$26.46	$25.97	$24.50	$24.90	$47.09	$29.20	$34.27	$68.62	$61.97	$55.91	$46.46	$80.25	$67.87	$54.38	$54.87
-.7%, 13000 BTU	$28.08	$27.58	$28.31	$26.60	$25.80	$25.28	$25.77	$25.15	$26.42	$50.06	$31.07	$38.49	$62.42	$66.01	$59.56	$49.50	$85.52	$61.68	$57.86	$58.62
-1.0%, 12500 BTU	$21.94	$24.01	$24.22	$22.84	$24.41	$24.02	$24.24	$23.29	$23.48	$44.09	$27.26	$32.04	$55.03	$57.49	$50.71	$44.35	$76.94	$54.65	$50.03	$46.34
-1.5%, 12500 BTU	$21.54	$22.92	$22.70	$21.72	$22.73	$23.05	$23.33	$22.07	$21.72	$38.50	$24.19	$29.19	$49.92	$63.18	$45.49	$40.72	$69.28	$39.78	$38.91	$42.00
Ohio																				
-4%, 12500 BTU	$19.79	$21.50	$20.83	$18.38	$18.25	$18.34	$18.05	$18.41	$18.88	$26.44	$20.72	$28.01	$33.25	$35.88	$32.65	$39.19	$69.01	$42.54	$35.36	$32.34
Illinois Basin																				
-3%, 11000 BTU (IL)	$18.83	$21.69	$19.86	$16.96	$17.71	$18.10	$18.25	$17.44	$16.83	$24.63	$18.71	$19.61	$26.12	$27.64	$27.01	$27.01	$35.91	$32.47	$33.37	$33.43
-3%, 11000 BTU (KY)	$20.03	$22.78	$20.95	$18.10	$19.29	$20.25	$19.90	$18.81	$17.51	$29.83	$22.34	$22.09	$29.19	$29.82	$29.06	$28.91	$37.81	$34.28	$35.18	$35.27
Powder River Basin																				
-.33%, 8400 BTU	$3.68	$3.26	$4.34	$3.60	$3.09	$3.13	$3.35	$3.46	$3.43	$7.68	$4.74	$5.13	$5.23	$7.86	$10.17	$8.38	$12.91	$10.88	$10.08	$10.22
-.35%, 8800 BTU	$4.68	$4.64	$5.08	$4.68	$4.11	$4.29	$4.45	$4.42	$4.38	$9.34	$5.86	$6.21	$6.28	$10.09	$12.74	$9.85	$15.56	$12.30	$11.49	$12.09
Uinta Basin																				
-.5%, 11500 BTU	$19.79	$19.36	$13.64	$14.08	$13.58	$15.18	$15.09	$14.19	$13.35	$20.06	$16.95	$17.13	$26.82	$33.11	$36.76	$29.93	$38.15	$28.99	$25.64	$24.88
Foreign Coal																				
-.7%, 12000 BTU	$28.74	$26.45	$28.05	$34.31	$32.76	$31.71	$29.31	$26.35	$27.69	$36.37	$27.70	$33.43	$59.18	$50.12	$50.53	$62.03	$105.40	$65.62	$56.25	$52.13
-.8%, 11600 BTU						$29.81	$26.70	$24.09	$25.79	$32.94	$26.04	$31.41	$55.40	$46.90	$47.22	$57.85	$88.30	$61.13	$52.57	$48.81
Petroleum Coke																				
-6%/30 HGI, 14000 BTU			$15.42	$12.65	$19.22	$19.39	$3.52	$1.71	$8.98	$12.73	$8.57	$13.03	$11.27	$17.50	$34.76	$44.90	$59.69	$48.09	$46.66	$39.99

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia																				
-1.8%, 13000 BTU	$35.40	$36.72	$32.91	$31.73	$33.65	$32.62	$30.91	$28.89	$28.79	$47.30	$34.85	$34.87	$54.91	$57.58	$46.99	$46.81	$77.70	$48.83	$39.03	$34.80
-1.8%, 13000 BTU	$34.68	$34.56	$31.11	$28.82	$28.68	$28.67	$29.23	$27.02	$27.88	$46.06	$33.71	$33.51	$53.40	$55.26	$44.82	$45.85	$76.17	$47.52	$38.22	$34.14
-2.3%, 13000 BTU	$31.00	$29.37	$28.44	$26.88	$27.08	$27.31	$27.83	$25.23	$28.37	$42.02	$31.56	$32.21	$52.32	$51.77	$40.82	$44.71	$73.88	$45.65	$37.01	$33.14
Central Appalachia																				
-.7%, 12500 BTU	$33.63	$36.19	$35.43	$32.27	$33.13	$31.88	$32.19	$29.92	$29.77	$54.97	$33.50	$38.51	$64.02	$65.56	$57.34	$46.46	$78.95	$55.98	$51.60	$51.04
-.7%, 13000 BTU	$36.08	$37.29	$37.49	$34.52	$32.86	$31.64	$31.93	$30.72	$31.58	$58.44	$35.65	$41.00	$68.17	$69.84	$61.09	$49.50	$84.14	$59.66	$56.02	$54.52
-1.0%, 12500 BTU	$30.36	$32.48	$32.07	$29.64	$31.10	$30.10	$30.04	$28.46	$28.03	$51.47	$31.27	$38.00	$60.10	$60.82	$52.00	$44.33	$76.69	$52.85	$47.47	$43.10
-1.5%, 12500 BTU	$28.80	$31.00	$30.08	$28.19	$28.96	$29.88	$28.91	$26.96	$25.98	$44.95	$27.76	$32.80	$54.53	$58.27	$46.65	$40.72	$68.30	$38.48	$37.87	$39.06
Ohio																				
-4%, 12500 BTU	$27.38	$29.08	$27.58	$23.86	$23.25	$22.98	$22.37	$22.49	$22.58	$30.88	$23.78	$25.86	$36.32	$37.96	$33.38	$39.19	$67.89	$41.15	$33.56	$30.08
Illinois Basin																				
-3%, 11000 BTU (IL)	$26.19	$29.31	$26.29	$22.02	$22.56	$22.68	$22.62	$21.30	$20.11	$28.76	$22.62	$22.04	$28.52	$29.14	$27.70	$27.01	$35.33	$31.40	$31.66	$31.10
-3%, 11000 BTU (KY)	$27.71	$30.80	$27.74	$23.49	$24.57	$25.37	$24.66	$22.88	$20.84	$34.93	$26.73	$24.82	$31.86	$31.54	$29.80	$28.91	$37.20	$33.15	$33.38	$32.81
Powder River Basin																				
-.33%, 8400 BTU	$4.95	$4.41	$5.74	$4.67	$3.93	$3.92	$4.15	$4.21	$4.09	$8.84	$5.44	$5.76	$5.71	$8.42	$10.43	$8.36	$12.70	$10.53	$9.56	$9.50
-.35%, 8800 BTU	$6.33	$6.27	$6.72	$6.07	$6.24	$5.37	$5.61	$5.40	$5.23	$10.90	$8.71	$6.88	$6.84	$10.67	$13.06	$9.85	$15.31	$11.89	$10.90	$11.24
Uinta Basin																				
-.6%, 11500 BTU	$27.38	$26.17	$18.06	$18.24	$17.29	$16.01	$18.70	$17.30	$15.96	$23.42	$19.45	$19.24	$29.29	$36.02	$37.70	$29.93	$37.54	$28.04	$24.23	$23.12
Foreign Coal: Colombia																				
-.7%, 12000 BTU	$39.76	$35.77	$57.15	$44.53	$41.73	$39.73	$38.32	$32.18	$33.34	$41.29	$31.70	$37.56	$64.84	$53.02	$51.82	$62.03	$103.69	$63.38	$53.37	$48.48
-.8%, 11600 BTU						$37.10	$33.09	$29.42	$30.83	$38.45	$29.87	$35.29	$60.50	$49.62	$48.43	$57.85	$96.71	$59.13	$49.88	$45.39
Petroleum Coke																				
-6%/30 HGI, 14000 BTU			$20.42	$16.29	$23.21	$24.30	$4.38	$2.09	$11.93	$14.86	$8.83	$14.64	$12.81	$18.52	$35.65	$44.90	$58.62	$46.51	$44.27	$37.19
IMPLICIT PRICE DEFLATOR (GDP)	88.40	88.39	90.27	92.10	93.85	95.41	96.47	97.86	100.00	102.40	104.19	106.40	109.45	112.99	116.56	119.54	121.51	123.59	126.00	128.53
% Change	2.77%	2.30%	2.12%	2.04%	1.89%	1.67%	1.11%	1.44%	2.18%	2.40%	1.74%	2.12%	2.87%	3.23%	3.16%	2.56%	1.65%	1.71%	1.95%	2.01%

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
[redacted]
March 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

[redacted]

Year: [redacted]
Quarter: [redacted]

Northern Appalachia																				
-1.6%, 13000 BTU	$24.73	$24.68	$28.27	$24.93	$26.78	$27.41	$26.78	$25.67	$25.77	$25.94	$25.72	$24.83	$24.63	$24.78	$24.43	$23.54	$23.29	$23.34	$22.80	$22.86
+1.8%, 13000 BTU	$22.16	$22.10	$23.29	$22.10	$22.35	$22.30	$22.40	$22.30	$23.06	$23.78	$23.79	$23.29	$23.84	$23.44	$22.80	$21.88	$21.41	$22.60	$22.03	$22.00
-2.3%, 13000 BTU	$20.98	$20.87	$21.81	$20.91	$21.21	$21.11	$21.21	$21.16	$22.01	$22.80	$22.80	$22.25	$22.80	$22.30	$21.51	$19.73	$19.92	$21.48	$21.11	$20.96
Central Appalachia																				
-.7%, 12500 BTU	$24.95	$24.70	$25.71	$24.50	$26.88	$26.97	$27.17	$24.55	$24.60	$25.60	$25.64	$25.27	$28.28	$26.71	$26.91	$24.14	$23.89	$24.04	$23.54	$23.39
-.7%, 13000 BTU	$26.49	$26.23	$25.60	$24.30	$26.65	$26.75	$26.95	$24.35	$24.30	$25.40	$25.43	$26.07	$28.07	$26.60	$25.70	$23.85	$25.46	$25.60	$24.98	$24.78
-1.0%, 12500 BTU	$22.92	$22.81	$24.11	$23.54	$24.90	$25.10	$25.21	$23.58	$23.33	$23.96	$24.08	$23.33	$24.48	$25.10	$24.32	$23.13	$22.92	$22.81	$22.34	$22.19
-1.5%, 12500 BTU	$21.61	$21.46	$22.50	$21.56	$23.44	$23.44	$23.54	$23.13	$22.40	$23.13	$23.18	$22.81	$23.33	$24.01	$23.13	$22.03	$21.82	$21.30	$20.73	$20.63
Ohio																				
-4%, 12500 BTU	$18.35	$18.25	$18.25	$18.20	$18.30	$18.25	$18.40	$18.30	$18.35	$18.30	$18.30	$18.10	$18.10	$17.70	$18.35	$18.00	$18.40	$18.90	$19.00	$18.25
Illinois Basin																				
-3%, 11000 BTU (IL)	$16.70	$ 18.85	$ 17.50	$ 17.35	$ 18.00	$ 18.00	$18.00	$18.00	$18.15	$18.25	$18.25	$17.95	$ 18.20	$ 18.60	$18.10	$17.50	$17.15	$17.00	$16.75	$16.70
-3%, 11000 BTU (KY)	$17.80	$ 18.10	$ 18.75	$ 18.50	$ 19.90	$ 20.00	$21.00	$20.05	$20.00	$19.95	$20.05	$19.35	$ 20.00	$ 20.20	$19.75	$19.00	$18.45	$18.05	$17.20	$16.96
Powder River Basin																				
-.33%, 8400 BTU	$3.40	$3.30	$3.20	$3.16	$3.00	$3.00	$3.00	$3.00	$3.20	$3.30	$3.62	$3.35	$3.15	$3.27	$3.38	$3.45	$3.47	$3.50	$3.40	$3.20
-.35%, 8800 BTU	$4.45	$4.40	$4.25	$4.20	$4.00	$4.00	$4.00	$4.05	$4.50	$4.60	$4.80	$4.45	$4.20	$4.34	$4.38	$4.45	$4.40	$4.45	$4.40	$4.20
Uinta Basin																				
-.5%, 11600 BTU	$14.20	$14.00	$13.50	$13.20	$13.60	$14.00	$14.40	$15.05	$15.65	$15.60	$15.25	$15.20	$ 15.10	$ 14.80	$14.65	$14.40	$14.10	$13.50	$12.75	$12.80
Foreign Coal																				
-.7%, 12000 BTU	$34.20	$34.50	$33.65	$32.15	$32.00	$33.25	$33.50	$32.40	$30.95	$30.00	$29.20	$29.00	$30.15	$29.80	$28.40	$28.00	$24.80	$24.40	$26.00	$27.25
-.8%, 11600 BTU							$31.54	$30.51	$28.69	$27.71	$26.61	$26.08	$27.99	$26.13	$25.63	$24.63	$23.34	$22.75	$24.13	$25.21
Petroleum Coke																				
-6%/30 HGI, 14000 BTU	$10.28	$11.79	$15.88	$17.24	$19.35	$20.41	$21.47	$21.02	$19.81	$15.27	$7.44	$3.93	$1.36	$1.36	$1.36	$1.36	$1.38	$2.75	$5.58	$6.73

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

ANNUAL AVERAGE SPOT

BASE CASE

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia									
-1.6%, 13000 BTU	$35.74	$34.76	$34.75	$35.09	$35.54	$36.08	$36.54	$37.02	$37.53
-1.8%, 13000 BTU	$35.12	$34.22	$34.33	$34.88	$35.15	$35.67	$36.17	$36.67	$37.21
-2.3%, 13000 BTU	$34.18	$33.40	$33.68	$34.07	$34.56	$35.08	$35.81	$36.14	$36.73
Central Appalachia									
-.7%, 12500 BTU	$54.93	$55.89	$56.32	$57.10	$58.07	$59.24	$60.63	$62.10	$63.62
-.7%, 13000 BTU	$58.84	$58.66	$60.12	$60.85	$61.98	$63.24	$64.71	$66.28	$67.91
-1.0%, 12500 BTU	$44.52	$42.80	$42.61	$42.88	$43.60	$44.39	$45.26	$46.09	$47.07
-1.5%, 12500 BTU	$41.28	$41.31	$41.48	$42.20	$42.99	$43.79	$44.66	$45.54	$46.53
Ohio									
-4%, 12500 BTU	$31.04	$30.34	$30.61	$30.98	$31.44	$31.93	$32.42	$32.92	$33.47
Illinois Basin									
-3%, 11000 BTU (IL)	$33.52	$33.62	$33.70	$33.91	$34.20	$34.53	$34.84	$35.18	$35.48
-3%, 11000 BTU (KY)	$35.37	$35.52	$35.66	$35.82	$36.27	$36.65	$37.02	$37.42	$37.78
Powder River Basin									
-.33%, 8400 BTU	$10.01	$9.86	$9.75	$9.80	$9.89	$10.12	$10.35	$10.58	$10.81
-.35%, 8800 BTU	$12.01	$12.03	$12.03	$12.17	$12.37	$12.63	$12.91	$13.21	$13.69
Uinta Basin									
-.5%, 11500 BTU	$24.00	$24.26	$24.59	$24.93	$25.31	$25.68	$26.06	$26.43	$26.85
Foreign Coal									
-.7%, 12000 BTU	$49.89	$49.93	$50.47	$51.00	$51.56	$52.23	$52.93	$53.60	$54.27
-.8%, 11800 BTU	$46.64	$47.02	$47.62	$48.26	$48.91	$49.57	$50.27	$50.96	$51.69
Petroleum Coke									
-6%/30 HGI, 14000 BTU	$37.26	$37.14	$37.52	$37.92	$38.36	$38.79	$39.25	$39.72	$40.21

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$38.24	$39.84	$40.46	$41.08	$41.75	$42.41	$43.07	$43.72	$44.38	$45.08
-1.8%, 13000 BTU	$38.69	$39.48	$40.11	$40.74	$41.39	$42.04	$42.70	$43.34	$43.99	$44.69
-2.3%, 13000 BTU	$38.38	$38.97	$39.58	$40.20	$40.86	$41.49	$42.14	$42.77	$43.41	$44.10
Central Appalachia										
-.7%, 12500 BTU	$65.95	$68.34	$70.14	$71.93	$73.84	$75.83	$77.84	$79.91	$81.97	$84.09
-.7%, 13000 BTU	$70.40	$72.99	$74.89	$76.81	$78.85	$80.89	$83.14	$85.36	$87.57	$89.84
-1.0%, 12500 BTU	$48.58	$50.16	$51.25	$52.38	$53.50	$54.65	$55.82	$57.00	$58.19	$59.46
-1.5%, 12500 BTU	$48.04	$49.63	$50.72	$51.83	$52.98	$54.14	$55.31	$56.50	$57.69	$58.98
Ohio										
-4%, 12500 BTU	$35.00	$35.55	$36.13	$36.71	$37.32	$37.92	$38.53	$39.13	$39.74	$40.36
Illinois Basin										
-3%, 11000 BTU (IL)	$35.87	$36.25	$36.63	$36.98	$37.33	$37.77	$38.23	$38.67	$39.11	$39.58
-3%, 11000 BTU (KY)	$38.23	$38.66	$39.10	$39.50	$39.92	$40.44	$40.96	$41.47	$41.97	$42.51
Powder River Basin										
-.33%, 8400 BTU	$11.16	$11.52	$11.72	$11.90	$12.10	$12.26	$12.46	$12.63	$12.80	$13.01
-.35%, 8800 BTU	$14.04	$14.48	$14.78	$15.06	$15.36	$15.63	$15.92	$16.22	$16.50	$16.84
Uinta Basin										
-.5%, 11500 BTU	$27.26	$27.67	$28.10	$28.53	$28.98	$29.43	$29.88	$30.33	$30.78	$31.26
Foreign Coal										
-.7%, 12000 BTU	$55.01	$55.80	$56.62	$57.49	$58.40	$59.38	$60.40	$61.44	$62.52	$63.57
-.8%, 11800 BTU	$52.44	$53.20	$54.00	$54.84	$55.73	$56.67	$57.64	$58.63	$59.56	$60.67
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$40.73	$41.28	$41.88	$42.48	$43.14	$43.85	$44.60	$45.37	$46.19	$46.97

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

ANNUAL AVERAGE SPOT

BASE CASE

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia									
-1.6%, 13000 BTU	$32.69	$31.11	$30.61	$30.22	$30.02	$29.88	$29.71	$29.59	$29.38
-1.8%, 13000 BTU	$32.02	$30.82	$30.18	$29.86	$29.68	$29.56	$28.40	$29.25	$29.14
-2.3%, 13000 BTU	$31.17	$29.26	$29.67	$29.34	$29.19	$29.07	$28.95	$28.83	$29.76
Central Appalachia									
-.7%, 12500 BTU	$50.09	$50.01	$49.45	$49.16	$49.04	$49.09	$49.29	$49.54	$49.82
-.7%, 13000 BTU	$53.49	$53.39	$52.78	$52.48	$52.36	$52.41	$52.61	$52.89	$53.19
-1.0%, 12500 BTU	$40.60	$38.30	$37.41	$37.01	$36.83	$36.79	$36.79	$36.78	$36.86
-1.5%, 12600 BTU	$37.53	$36.97	$36.42	$36.34	$36.31	$36.29	$36.30	$36.34	$36.44
Ohio									
-4%, 12500 BTU	$28.30	$27.15	$26.87	$26.67	$26.56	$26.46	$26.36	$26.27	$26.21
Illinois Basin									
-3%, 11000 BTU (IL)	$30.67	$30.08	$29.59	$29.20	$28.88	$28.61	$28.33	$28.07	$27.78
-3%, 11000 BTU (KY)	$32.26	$31.78	$31.30	$30.93	$30.63	$30.37	$30.10	$29.86	$29.58
Powder River Basin									
-.33%, 8400 BTU	$9.13	$8.82	$8.56	$8.44	$8.36	$8.39	$8.41	$8.43	$8.47
-.35%, 8800 BTU	$10.98	$10.78	$10.56	$10.48	$10.46	$10.47	$10.49	$10.64	$10.64
Uinta Basin									
-.5%, 11500 BTU	$21.89	$21.71	$21.59	$21.47	$21.38	$21.28	$21.17	$21.09	$21.03
Foreign Coal: Colombia									
-.7%, 12000 BTU	$45.49	$44.89	$44.31	$43.92	$43.54	$43.29	$43.03	$42.77	$42.60
-.8%, 11600 BTU	$42.71	$42.08	$41.80	$41.56	$41.31	$41.08	$40.87	$40.66	$40.49
Petroleum Coke									
-6%/30 HGI, 14000 BTU	$33.98	$33.24	$32.83	$32.65	$32.39	$32.14	$31.91	$31.69	$31.49
IMPLICIT PRICE DEFLATOR (GDP)	131.09	133.58	136.17	138.84	141.54	144.25	147.05	149.83	152.66
% Change	1.99%	1.90%	1.93%	1.96%	1.95%	1.91%	1.94%	1.89%	1.89%

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$30.18	$30.07	$29.89	$29.90	$29.82	$29.73	$29.64	$29.54	$29.44	$29.37
-1.8%, 13000 BTU	$29.90	$29.81	$29.73	$29.64	$28.56	$29.47	$29.38	$29.28	$29.19	$29.11
-2.3%, 13000 BTU	$29.60	$29.42	$29.34	$29.25	$29.18	$29.09	$28.98	$28.60	$28.80	$28.73
Central Appalachia										
-.7%, 12500 BTU	$50.69	$51.58	$51.98	$52.34	$52.74	$53.16	$53.56	$53.98	$54.38	$54.78
-.7%, 13000 BTU	$54.12	$55.07	$55.61	$55.89	$56.32	$56.77	$57.21	$57.67	$58.10	$58.53
-1.0%, 12500 BTU	$37.34	$37.86	$37.98	$38.09	$38.21	$38.31	$38.41	$38.51	$38.60	$38.74
-1.5%, 12600 BTU	$36.93	$37.46	$37.59	$37.71	$37.84	$37.95	$38.06	$38.17	$38.27	$38.41
Ohio										
-4%, 12500 BTU	$26.90	$26.84	$26.78	$26.71	$26.65	$26.58	$26.51	$26.44	$26.38	$26.31
Illinois Basin										
-3%, 11000 BTU (IL)	$27.58	$27.36	$27.16	$26.98	$26.86	$26.48	$26.30	$26.13	$25.95	$25.79
-3%, 11000 BTU (KY)	$29.28	$29.18	$28.98	$28.74	$28.52	$28.35	$28.18	$28.02	$27.85	$27.70
Powder River Basin										
-.33%, 8400 BTU	$8.58	$8.69	$8.68	$8.66	$8.64	$8.60	$8.57	$8.54	$8.49	$8.48
-.35%, 8800 BTU	$10.78	$10.93	$10.96	$10.96	$10.97	$10.96	$10.96	$10.96	$10.95	$10.97
Uinta Basin										
-.5%, 11500 BTU	$20.96	$20.89	$20.82	$20.76	$20.70	$20.63	$20.56	$20.49	$20.42	$20.36
Foreign Coal: Colombia										
-.7%, 12000 BTU	$42.29	$42.12	$41.96	$41.83	$41.72	$41.63	$41.59	$41.51	$41.48	$41.41
-.8%, 11600 BTU	$40.31	$40.16	$40.02	$39.91	$39.81	$39.73	$39.66	$39.61	$39.58	$39.52
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$31.31	$31.16	$31.02	$30.91	$30.81	$30.74	$30.69	$30.66	$30.64	$30.60
IMPLICIT PRICE DEFLATOR (GDP)	155.51	158.37	161.30	164.29	167.36	170.52	173.73	176.94	180.18	183.49
% Change	1.87%	1.84%	1.85%	1.85%	1.87%	1.89%	1.88%	1.85%	1.83%	1.84%

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
[illegible]
March 2008

QUARTERLY SPOT PRICE
[illegible]

Year / Quarter	Q3	Q4	Q1	Q2	Q3	Q4	2002 Q1	Q2	Q3	Q4	2003 Q1
Northern Appalachia											
-1.6%, 13000 BTU	$24.38	$28.12	$32.86	$42.38	$43.91	$42.92	$35.34	$29.34	$29.09	$27.70	$28.20
-1.8%, 13000 BTU	$23.59	$24.65	$31.91	$41.28	$42.81	$41.85	$34.32	$28.38	$28.09	$26.73	$27.01
-2.3%, 13000 BTU	$22.55	$23.59	$29.38	$37.07	$38.40	$38.11	$31.57	$26.61	$26.66	$25.18	$25.82
Central Appalachia											
-.7%, 12500 BTU	$24.66	$28.02	$46.72	$61.11	$49.19	$41.33	$30.14	$27.67	$28.23	$29.74	$32.36
-.7%, 13000 BTU	$26.17	$29.77	$49.66	$64.33	$52.31	$43.93	$32.07	$29.43	$31.12	$31.55	$34.44
-1.0%, 12500 BTU	$22.92	$26.35	$43.07	$48.65	$45.89	$38.75	$28.18	$25.64	$27.24	$27.66	$29.43
-1.5%, 12500 BTU	$21.04	$24.48	$34.69	$43.66	$41.15	$34.53	$24.22	$22.66	$24.53	$25.16	$26.93
Ohio											
-4%, 12500 BTU	$19.75	$19.55	$23.95	$26.85	$27.65	$27.10	$22.34	$20.15	$20.45	$19.96	$21.40
Illinois Basin											
-3%, 11000 BTU (IL)	$16.80	$17.05	$22.05	$25.35	$25.65	$25.46	$21.90	$19.80	$18.50	$18.65	$18.80
-3%, 11000 BTU (KY)	$17.45	$18.45	$24.30	$31.45	$32.10	$31.85	$27.80	$22.60	$21.60	$21.45	$21.45
Powder River Basin											
-.33%, 8400 BTU	$3.40	$3.70	$6.25	$10.65	$7.05	$6.35	$4.65	$4.70	$4.68	$4.85	$5.00
-.35%, 8800 BTU	$4.35	$4.55	$7.90	$12.75	$8.70	$8.00	$5.85	$5.75	$5.75	$6.05	$6.00
Uinta Basin											
-.5%, 11500 BTU	$13.30	$14.65	$19.05	$19.85	$20.65	$20.80	$18.40	$16.30	$16.45	$15.65	$15.15
Foreign Coal											
-.7%, 12000 BTU	$27.86	$30.46	$35.10	$36.80	$38.85	$32.62	$29.81	$27.64	$25.06	$28.38	$28.55
-.8%, 11600 BTU	$25.63	$28.20	$32.60	$34.32	$34.31	$30.52	$27.89	$25.95	$23.67	$26.63	$26.83
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$8.83	$19.78	$18.11	$14.62	$9.95	$8.24	$7.44	$6.79	$7.97	$13.08	$20.35

Year / Quarter	Q2	Q3	Q4	2004 Q1	Q2	Q3	Q4	2005 Q1	Q2	Q3	Q4
Northern Appalachia											
-1.6%, 13000 BTU	$30.88	$31.57	$33.50	$41.24	$45.53	$52.70	$61.62	$56.60	$54.24	$53.91	$52.96
-1.8%, 13000 BTU	$29.66	$30.41	$32.23	$40.04	$44.46	$51.30	$59.78	$55.15	$52.33	$51.52	$49.91
-2.3%, 13000 BTU	$28.60	$29.34	$31.03	$39.12	$43.84	$50.32	$58.33	$52.98	$49.48	$47.94	$46.35
Central Appalachia											
-.7%, 12500 BTU	$34.02	$33.87	$36.84	$49.62	$56.75	$62.95	$68.15	$62.35	$63.07	$60.38	$62.08
-.7%, 13000 BTU	$38.21	$36.07	$39.24	$52.84	$60.43	$67.05	$68.37	$66.41	$67.18	$64.33	$66.12
-1.0%, 12500 BTU	$31.77	$31.93	$35.05	$47.98	$54.08	$58.30	$59.76	$57.71	$58.20	$56.23	$59.81
-1.5%, 12500 BTU	$28.85	$28.96	$32.03	$44.34	$49.69	$53.05	$52.61	$53.50	$54.86	$52.78	$51.59
Ohio											
-4%, 12500 BTU	$22.85	$23.35	$24.35	$28.09	$28.78	$35.38	$40.77	$36.72	$35.18	$38.75	$35.85
Illinois Basin											
-3%, 11000 BTU (IL)	$19.55	$19.60	$20.50	$22.55	$25.07	$28.80	$30.06	$27.32	$27.22	$27.76	$27.88
-3%, 11000 BTU (KY)	$21.95	$22.10	$22.85	$24.95	$28.06	$30.60	$33.20	$30.03	$28.25	$29.83	$30.16
Powder River Basin											
-.33%, 8400 BTU	$4.80	$5.25	$5.45	$5.55	$5.43	$6.00	$4.93	$5.18	$6.35	$7.72	$12.57
-.35%, 8800 BTU	$5.80	$6.30	$6.66	$6.58	$6.43	$6.02	$6.02	$6.33	$7.88	$10.03	$16.00
Uinta Basin											
-.5%, 11500 BTU	$16.90	$17.15	$18.30	$22.42	$25.95	$29.42	$28.60	$28.88	$31.12	$34.82	$37.50
Foreign Coal											
-.7%, 12000 BTU	$29.04	$35.00	$42.12	$46.23	$54.39	$68.60	$67.62	$57.64	$49.06	$51.92	$41.84
-.8%, 11600 BTU	$26.40	$32.86	$39.55	$43.28	$50.97	$64.08	$63.25	$53.92	$45.94	$48.57	$39.17
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$14.53	$8.52	$8.71	$6.60	$6.46	$14.71	$20.46	$22.76	$13.25	$12.02	$21.98

QCF (QUARTERLY COAL FORECST) - 200803
JD Energy, Inc.
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QUARTERLY SPOT PRICE:

[illegible]

Year:	2006				2007				2008	
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Northern Appalachia										
-1.6%, 13000 BTU	$48.63	$46.60	$44.14	$42.90	$44.00	$44.75	$46.60	$51.10	$73.95	$88.06
-1.8%, 13000 BTU	$46.48	$43.85	$41.82	$41.40	$43.09	$44.02	$45.83	$50.48	$72.73	$86.53
-2.3%, 13000 BTU	$41.76	$39.72	$38.68	$39.14	$41.73	$42.93	$44.67	$49.80	$70.80	$84.25
Central Appalachia										
-.7%, 12500 BTU	$61.21	$59.39	$54.23	$48.82	$41.92	$44.73	$45.85	$53.55	$74.38	$88.33
-.7%, 13000 BTU	$66.20	$63.26	$57.79	$52.01	$44.65	$47.65	$48.85	$57.06	$79.26	$95.18
-1.0%, 12500 BTU	$65.10	$61.61	$49.69	$46.23	$39.55	$42.53	$43.65	$51.60	$71.43	$85.48
-1.5%, 12500 BTU	$48.97	$46.26	$44.09	$42.62	$35.52	$39.22	$40.17	$47.98	$63.05	$67.21
Ohio										
-4%, 12500 BTU	$34.63	$32.63	$30.67	$32.24	$35.45	$37.43	$38.63	$46.23	$85.86	$78.04
Illinois Basin										
-3%, 11000 BTU (IL)	$27.27	$26.63	$28.63	$27.80	$26.85	$26.63	$26.93	$27.73	$32.13	$39.42
-3%, 11000 BTU (KY)	$29.37	$28.87	$28.72	$29.68	$28.77	$28.52	$28.77	$29.60	$34.05	$41.40
Powder River Basin										
-.33%, 8400 BTU	$14.20	$10.63	$8.20	$7.63	$7.16	$7.48	$8.92	$9.86	$11.97	$13.85
-.35%, 8800 BTU	$17.68	$13.62	$10.18	$9.47	$8.80	$8.93	$10.47	$11.20	$14.42	$17.25
Uinta Basin										
-.6%, 11500 BTU	$38.45	$37.62	$35.83	$35.13	$33.75	$32.50	$27.02	$26.43	$34.83	$42.40
Foreign Coal										
-.7%, 12000 BTU	$48.83	$52.74	$50.93	$49.61	$51.13	$52.48	$59.37	$85.13	$111.06	$123.68
-.8%, 11600 BTU	$45.68	$49.24	$47.65	$46.32	$47.70	$48.95	$55.37	$79.38	$103.60	$115.38
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$24.99	$36.75	$39.32	$37.98	$44.03	$47.68	$44.98	$42.80	$35.19	$70.38

Year:			2009				2010			
Quarter:	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia										
-1.6%, 13000 BTU	$82.60	$71.42	$58.77	$49.90	$48.48	$44.79	$42.93	$41.18	$41.03	$39.42
-1.8%, 13000 BTU	$80.85	$69.60	$57.15	$48.43	$47.20	$43.74	$42.01	$40.22	$40.24	$38.68
-2.3%, 13000 BTU	$78.37	$66.88	$54.73	$48.22	$46.27	$42.17	$40.63	$38.77	$39.05	$37.57
Central Appalachia										
-.7%, 12500 BTU	$85.03	$72.27	$61.70	$57.33	$57.10	$55.35	$54.95	$54.08	$54.77	$53.73
-.7%, 13000 BTU	$90.63	$77.01	$65.76	$61.10	$60.87	$59.00	$58.59	$57.65	$58.40	$57.28
-1.0%, 12500 BTU	$81.50	$68.35	$58.85	$54.25	$53.77	$51.75	$51.05	$49.88	$50.27	$48.93
-1.5%, 12500 BTU	$58.57	$47.20	$41.20	$38.85	$39.65	$38.35	$39.67	$39.35	$40.38	$40.25
Ohio										
-4%, 12500 BTU	$71.70	$60.44	$49.28	$41.73	$40.95	$38.21	$38.86	$35.13	$35.42	$34.05
Illinois Basin										
-3%, 11000 BTU (IL)	$38.23	$33.85	$32.07	$32.27	$32.83	$32.70	$32.98	$32.98	$33.93	$33.59
-3%, 11000 BTU (KY)	$40.07	$35.72	$33.88	$34.13	$34.80	$34.48	$34.80	$34.85	$35.70	$35.37
Powder River Basin										
-.33%, 8400 BTU	$13.15	$12.68	$12.22	$11.60	$10.48	$9.33	$9.83	$9.70	$10.50	$10.28
-.35%, 8800 BTU	$16.97	$14.62	$13.65	$12.82	$11.82	$10.80	$11.27	$11.12	$11.63	$11.75
Uinta Basin										
-.6%, 11500 BTU	$39.70	$35.68	$32.52	$29.07	$27.90	$26.47	$25.80	$25.40	$25.83	$25.32
Foreign Coal										
-.7%, 12000 BTU	$105.18	$81.68	$70.69	$66.43	$63.52	$61.45	$59.55	$55.20	$56.82	$52.44
-.8%, 11600 BTU	$92.07	$79.17	$65.93	$61.96	$59.27	$57.35	$55.02	$51.57	$53.12	$49.96
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$60.30	$52.48	$49.98	$47.62	$47.55	$47.20	$46.93	$46.63	$47.30	$45.76

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

	Cell
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ANNUAL AVERAGE CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$72.15	$49.33	$40.12	$37.61	$36.31	$35.88	$36.05	$36.46	$36.96	$37.47	$37.97	$38.68	$39.64
-1.8%, 13000 BTU	$70.51	$48.28	$39.38	$36.83	$35.73	$35.36	$35.62	$36.05	$36.56	$37.08	$37.60	$38.34	$39.30
-2.3%, 13000 BTU	$68.06	$46.70	$38.27	$35.82	$34.85	$34.61	$34.98	$35.43	$35.95	$36.50	$37.05	$37.81	$38.78
Central Appalachia													
-.7%, 12500 BTU	$73.85	$57.43	$55.24	$56.71	$57.15	$57.92	$58.58	$59.51	$60.65	$61.98	$63.46	$65.14	$67.14
-.7%, 13000 BTU	$78.72	$61.23	$58.93	$60.57	$61.01	$61.83	$62.53	$63.53	$64.74	$66.17	$67.74	$69.54	$71.67
-1.0%, 12500 BTU	$69.14	$52.38	$49.31	$46.50	$44.94	$44.05	$44.19	$44.73	$45.47	$46.31	$47.21	$48.24	$49.53
-1.5%, 12500 BTU	$55.50	$40.88	$41.23	$42.89	$42.56	$42.76	$43.23	$44.01	$44.84	$45.70	$46.62	$47.68	$48.98
Ohio													
-4%, 12500 BTU	$61.80	$42.50	$34.64	$32.52	$31.66	$31.45	$31.80	$32.23	$32.72	$33.23	$33.75	$34.46	$35.36
Illinois Basin													
-3%, 11000 BTU (IL)	$34.94	$33.31	$34.42	$34.50	$34.59	$34.70	$34.87	$35.13	$35.45	$35.79	$36.12	$36.46	$36.81
-3%, 11000 BTU (KY)	$36.83	$35.13	$36.30	$36.41	$36.53	$36.70	$36.92	$37.25	$37.62	$38.01	$38.40	$38.81	$39.22
Powder River Basin													
-.33%, 8400 BTU	$12.69	$10.74	$10.42	$10.39	$10.21	$10.11	$10.08	$10.18	$10.35	$10.58	$10.81	$11.07	$11.38
-.35%, 8800 BTU	$14.65	$12.46	$12.13	$12.42	$12.38	$12.41	$12.49	$12.68	$12.92	$13.21	$13.52	$13.88	$14.30
Uinta Basin													
-.5%, 11500 BTU	$33.60	$27.60	$25.81	$26.21	$24.91	$25.22	$25.57	$25.94	$26.32	$26.70	$27.10	$27.51	$27.94
Foreign Coal													
-.7%, 12000 BTU	$81.21	$60.35	$55.43	$52.54	$51.50	$51.80	$52.36	$52.93	$53.57	$54.27	$54.98	$55.68	$56.42
-.8%, 11600 BTU	$75.81	$56.44	$51.87	$49.29	$48.44	$48.85	$49.49	$50.15	$50.84	$51.54	$52.26	$53.00	$53.76
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$53.71	$47.54	$44.16	$39.76	$38.38	$38.52	$38.92	$39.36	$39.80	$40.27	$40.75	$41.25	$41.78

QCF (QUARTERLY
COAL FORECST)- 200803
JD Energy, Inc.
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ANNUAL AVERAGE CONTRACT PRICES - REAL 2007 DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$70.98	$47.71	$38.07	$34.88	$33.11	$32.09	$31.65	$31.40	$31.21	$31.05	$30.87	$30.87	$31.04
-1.8%, 13000 BTU	$69.37	$46.69	$37.37	$34.26	$32.58	$31.64	$31.27	$31.04	$30.87	$30.73	$30.57	$30.69	$30.77
-2.3%, 13000 BTU	$66.95	$45.17	$36.31	$33.31	$31.78	$30.98	$30.71	$30.51	$30.37	$30.24	$30.12	$30.17	$30.37
Central Appalachia													
-.7%, 12500 BTU	$72.65	$55.56	$52.41	$52.75	$52.11	$51.83	$51.43	$51.24	$51.22	$51.37	$51.59	$51.98	$52.57
-.7%, 13000 BTU	$77.44	$59.23	$55.81	$56.33	$55.63	$55.33	$54.89	$54.70	$54.88	$54.83	$55.07	$55.46	$56.12
-1.0%, 12500 BTU	$68.02	$50.66	$46.78	$43.25	$40.98	$39.42	$38.79	$38.51	$38.40	$38.38	$38.38	$38.49	$38.78
-1.5%, 12500 BTU	$54.60	$39.52	$39.11	$39.89	$38.81	$38.27	$37.98	$37.90	$37.87	$37.87	$37.90	$38.04	$38.35
Ohio													
-4%, 12500 BTU	$60.80	$41.11	$32.87	$30.24	$28.87	$28.15	$27.92	$27.75	$27.63	$27.53	$27.43	$27.49	$27.69
Illinois Basin													
-3%, 11000 BTU (IL)	$34.37	$32.21	$32.66	$32.09	$31.54	$31.06	$30.61	$30.25	$29.94	$29.66	$29.36	$29.09	$28.83
-3%, 11000 BTU (KY)	$36.24	$33.98	$34.44	$33.86	$33.31	$32.84	$32.41	$32.07	$31.77	$31.50	$31.22	$30.96	$30.71
Powder River Basin													
-.33%, 8400 BTU	$12.48	$10.39	$9.88	$9.86	$9.31	$9.04	$8.85	$8.76	$8.74	$8.77	$8.79	$8.83	$8.91
-.35%, 8800 BTU	$14.41	$12.06	$11.51	$11.55	$11.29	$11.11	$10.97	$10.92	$10.91	$10.94	$10.89	$11.07	$11.20
Uinta Basin													
-.5%, 11500 BTU	$33.05	$26.70	$24.48	$23.44	$22.72	$22.57	$22.45	$22.34	$22.23	$22.13	$22.03	$21.95	$21.88
Foreign Coal: Colombia													
-.7%, 12000 BTU	$79.89	$58.38	$52.59	$48.87	$46.96	$46.36	$45.96	$45.58	$45.24	$44.98	$44.70	$44.43	$44.18
-.8%, 11600 BTU	$74.58	$54.59	$49.22	$45.84	$44.17	$43.71	$43.44	$43.18	$42.94	$42.71	$42.48	$42.28	$42.09
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$52.84	$45.98	$41.89	$36.93	$35.00	$34.47	$34.17	$33.89	$33.62	$33.37	$33.13	$32.91	$32.72

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE [redacted]

March 2008

QUARTERLY CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE [redacted]

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$72.06	$78.83	$72.78	$64.83	$56.49	$48.00	$47.43	$45.39	$41.81	$40.00	$39.81	$38.87
-1.8%, 13000 BTU	$70.47	$77.05	$71.10	$63.42	$55.21	$46.96	$46.44	$44.49	$41.01	$39.25	$39.09	$38.18
-2.3%, 13000 BTU	$68.09	$74.39	$88.59	$61.16	$53.29	$45.39	$44.97	$43.14	$39.80	$38.13	$38.01	$37.15
Central Appalachia												
-.7%, 12500 BTU	$75.06	$79.18	$75.47	$85.68	$58.53	$57.43	$57.25	$56.50	$55.80	$55.29	$54.85	$55.00
-.7%, 13000 BTU	$80.00	$84.40	$80.45	$70.01	$62.40	$61.23	$61.04	$60.25	$59.52	$58.99	$58.53	$58.69
-1.0%, 12500 BTU	$70.81	$74.35	$70.50	$60.90	$53.88	$52.52	$52.05	$51.07	$50.18	$49.46	$48.85	$48.75
-1.5%, 12500 BTU	$60.95	$61.57	$53.60	$46.87	$40.65	$40.73	$41.06	$41.06	$41.07	$41.16	$41.28	$41.40
Ohio												
-4%, 12500 BTU	$62.05	$67.63	$62.17	$55.36	$48.26	$41.22	$40.94	$39.57	$36.78	$35.50	$35.66	$35.12
Illinois Basin												
-3%, 11000 BTU (IL)	$34.06	$36.49	$35.95	$33.26	$33.16	$33.27	$33.36	$33.43	$33.45	$33.50	$33.55	$33.53
-3%, 11000 BTU (KY)	$35.90	$38.45	$37.90	$35.09	$34.98	$35.10	$35.18	$35.26	$35.28	$35.34	$35.38	$35.38
Powder River Basin												
-.33%, 8400 BTU	$12.11	$13.58	$12.68	$12.39	$11.73	$10.74	$10.42	$10.07	$10.10	$10.11	$10.12	$10.07
-.35%, 8800 BTU	$14.06	$15.73	$14.58	$14.22	$13.49	$12.43	$12.13	$11.80	$11.87	$11.93	$11.99	$12.02
Uinta Basin												
-.5%, 11500 BTU	$33.12	$35.19	$34.05	$32.03	$29.60	$28.09	$26.67	$26.06	$25.53	$25.37	$25.24	$25.15
Foreign Coal												
-.7%, 12000 BTU	$88.57	$86.35	$79.15	$70.75	$63.16	$60.25	$59.91	$58.08	$56.35	$55.45	$54.93	$53.38
-.8%, 11600 BTU	$82.66	$80.60	$73.90	$66.09	$59.02	$56.33	$56.04	$54.36	$52.78	$51.97	$51.51	$50.09
Petroleum Coke												
6%/30 HGI, 14000 BTU	$56.16	$56.54	$52.59	$49.55	$48.06	$47.76	$47.21	$47.11	$46.13	$45.24	$45.14	$43.03

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
BASE CASE
March 2008

ANNUAL AVERAGE CONTF

BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$40.83	$41.46	$42.12	$42.78	$43.46	$44.14	$44.81	$45.49	$46.19	$46.89
-1.8%, 13000 BTU	$40.48	$41.10	$41.75	$42.41	$43.08	$43.75	$44.42	$45.10	$45.78	$46.48
-2.3%, 13000 BTU	$39.94	$40.56	$41.20	$41.85	$42.51	$43.18	$43.84	$44.50	$45.18	$45.87
Central Appalachia										
-.7%, 12500 BTU	$69.47	$71.62	$73.49	$75.41	$77.42	$79.49	$81.59	$83.73	$85.89	$88.08
-.7%, 13000 BTU	$74.16	$76.47	$78.48	$80.53	$82.69	$84.91	$87.16	$89.45	$91.76	$94.12
-1.0%, 12500 BTU	$51.04	$52.41	$53.55	$54.71	$55.90	$57.10	$58.31	$59.54	$60.80	$62.11
-1.5%, 12500 BTU	$50.49	$51.87	$53.01	$54.18	$55.37	$56.57	$57.79	$59.02	$60.29	$61.59
Ohio										
-4%, 12500 BTU	$36.43	$37.02	$37.62	$38.23	$38.85	$39.48	$40.10	$40.73	$41.37	$42.01
Illinois Basin										
-3%, 11000 BTU (IL)	$37.21	$37.59	$37.96	$38.33	$38.75	$39.22	$39.68	$40.14	$40.60	$41.08
-3%, 11000 BTU (KY)	$39.67	$40.12	$40.55	$40.99	$41.47	$42.00	$42.54	$43.07	$43.60	$44.14
Powder River Basin										
-.33%, 8400 BTU	$11.71	$12.00	$12.20	$12.39	$12.58	$12.76	$12.94	$13.13	$13.33	$13.54
-.35%, 8800 BTU	$14.74	$15.12	$15.42	$15.71	$16.01	$16.30	$16.60	$16.91	$17.23	$17.59
Uinta Basin										
-.5%, 11500 BTU	$28.36	$28.79	$29.24	$29.69	$30.16	$30.62	$31.09	$31.56	$32.03	$32.50
Foreign Coal										
-.7%, 12000 BTU	$57.21	$58.05	$58.82	$59.85	$60.83	$61.87	$62.93	$64.02	$65.11	$66.18
-.8%, 11600 BTU	$54.64	$55.35	$56.21	$57.11	$58.05	$59.04	$60.06	$61.09	$62.14	$63.15
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$42.33	$42.92	$43.54	$44.21	$44.93	$45.68	$46.48	$47.29	$48.10	$48.88

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.

BASE CASE

March 2008

ANNUAL AVERAGE CONTF

BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$31.39	$31.30	$31.21	$31.13	$31.04	$30.94	$30.84	$30.74	$30.64	$30.55
-1.8%, 13000 BTU	$31.11	$31.03	$30.94	$30.86	$30.77	$30.67	$30.57	$30.47	$30.37	$30.28
-2.3%, 13000 BTU	$30.70	$30.62	$30.54	$30.45	$30.37	$30.27	$30.17	$30.07	$29.98	$29.88
Central Appalachia										
-.7%, 12500 BTU	$53.40	$54.06	$54.47	$54.87	$55.30	$55.73	$56.15	$56.57	$56.98	$57.38
-.7%, 13000 BTU	$57.01	$57.72	$58.16	$58.60	$59.06	$59.52	$59.97	$60.43	$60.88	$61.31
-1.0%, 12500 BTU	$39.23	$39.56	$39.69	$39.81	$39.93	$40.03	$40.12	$40.23	$40.34	$40.46
-1.5%, 12500 BTU	$38.81	$39.15	$39.29	$39.42	$39.56	$39.66	$39.76	$39.88	$40.00	$40.12
Ohio										
-4%, 12500 BTU	$28.01	$27.94	$27.88	$27.82	$27.75	$27.67	$27.59	$27.52	$27.44	$27.37
Illinois Basin										
-3%, 11000 BTU (IL)	$28.60	$28.37	$28.13	$27.89	$27.68	$27.49	$27.30	$27.12	$26.94	$26.76
-3%, 11000 BTU (KY)	$30.50	$30.28	$30.05	$29.83	$29.62	$29.45	$29.27	$29.10	$28.92	$28.76
Powder River Basin										
-.33%, 8400 BTU	$9.00	$9.05	$9.04	$9.01	$8.98	$8.94	$8.91	$8.87	$8.84	$8.82
-.35%, 8800 BTU	$11.33	$11.41	$11.43	$11.43	$11.44	$11.43	$11.42	$11.42	$11.43	$11.46
Uinta Basin										
-.5%, 11500 BTU	$21.80	$21.73	$21.67	$21.61	$21.54	$21.47	$21.39	$21.32	$21.25	$21.18
Foreign Coal: Colombia										
-.7%, 12000 BTU	$43.98	$43.82	$43.67	$43.55	$43.45	$43.37	$43.30	$43.25	$43.20	$43.11
-.8%, 11600 BTU	$41.93	$41.78	$41.66	$41.55	$41.47	$41.39	$41.32	$41.28	$41.22	$41.14
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$32.54	$32.40	$32.27	$32.17	$32.09	$32.03	$31.98	$31.95	$31.91	$31.85

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
HIGH CASE
March 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON
HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$100.66	$105.86	$77.01	$62.98	$62.98	$63.45	$63.67	$64.41	$65.15	$65.97	$66.70	$67.38
-1.8%, 13000 BTU	$45.85	$98.64	$103.11	$75.40	$61.75	$61.88	$62.46	$62.89	$63.66	$64.43	$65.25	$66.02	$66.75
-2.3%, 13000 BTU	$44.71	$95.60	$98.85	$73.00	$59.95	$60.24	$60.96	$61.71	$62.53	$63.35	$64.18	$65.00	$65.79
Central Appalachia													
-.7%, 12500 BTU	$46.46	$78.41	$104.96	$88.47	$78.60	$70.39	$71.54	$72.66	$73.56	$75.07	$76.90	$78.74	$80.62
-.7%, 13000 BTU	$49.60	$83.56	$111.87	$94.34	$85.03	$75.15	$76.37	$77.57	$78.52	$80.14	$82.09	$84.05	$86.05
-1.0%, 12500 BTU	$44.33	$75.18	$89.12	$81.39	$67.22	$57.05	$54.78	$54.97	$55.37	$56.37	$57.62	$58.78	$59.84
-1.5%, 12500 BTU	$40.72	$57.90	$72.16	$84.93	$60.92	$52.88	$52.88	$53.62	$54.37	$55.58	$56.84	$58.00	$59.12
Ohio													
-4%, 12500 BTU	$39.19	$87.71	$89.29	$66.19	$51.87	$50.95	$50.22	$51.04	$51.96	$53.06	$54.18	$55.28	$56.31
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$43.75	$47.01	$41.11	$39.22	$39.76	$40.32	$40.86	$41.56	$42.37	$43.23	$44.08	$44.98
-3%, 11000 BTU (KY)	$28.91	$46.06	$49.63	$43.34	$41.37	$41.96	$42.60	$43.23	$44.03	$44.93	$45.89	$46.84	$47.84
Powder River Basin													
-.33%, 8400 BTU	$8.36	$15.29	$16.34	$13.55	$11.46	$11.46	$11.52	$11.62	$11.90	$12.27	$12.81	$13.37	$13.92
-.35%, 8800 BTU	$9.85	$16.87	$17.72	$15.13	$13.65	$13.76	$14.08	$14.33	$14.78	$15.33	$15.99	$16.68	$17.42
Uinta Basin													
-.5%, 11500 BTU	$29.93	$48.95	$50.65	$47.38	$44.44	$43.05	$43.10	$42.89	$43.02	$43.15	$42.49	$41.70	$40.18
Foreign Coal													
-.7%, 12000 BTU	$62.03	$136.25	$145.03	$108.60	$93.31	$81.37	$74.60	$70.07	$68.76	$70.07	$71.47	$72.81	$73.94
-.8%, 11600 BTU	$57.85	$127.07	$135.30	$101.49	$87.36	$76.41	$70.24	$66.11	$65.05	$66.48	$67.83	$69.14	$70.30
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$78.30	$106.44	$89.90	$71.58	$60.79	$55.49	$52.08	$51.12	$52.13	$53.07	$53.99	$54.78

QCF (QUARTERLY
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JD Energy, Inc.
HIGH CASE
March 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON
HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013
Northern Appalachia							
-1.6%, 13000 BTU	$46.61	$98.03	$102.49	$73.07	$58.55	$57.43	$56.78
-1.8%, 13000 BTU	$45.85	$97.04	$99.74	$71.54	$57.44	$56.43	$55.89
-2.3%, 13000 BTU	$44.71	$94.05	$95.61	$69.26	$55.76	$54.93	$54.56
Central Appalachia							
-.7%, 12500 BTU	$46.46	$77.14	$101.52	$83.93	$74.03	$64.19	$64.02
-.7%, 13000 BTU	$49.50	$82.21	$108.21	$89.51	$79.08	$68.53	$68.34
-1.0%, 12500 BTU	$44.33	$73.98	$95.88	$77.22	$62.52	$52.03	$49.02
-1.5%, 12500 BTU	$40.72	$56.96	$69.80	$61.60	$56.66	$48.22	$47.32
Ohio							
-4%, 12500 BTU	$39.19	$86.29	$86.37	$62.80	$48.24	$46.46	$44.94
Illinois Basin							
-3%, 11000 BTU (IL)	$27.01	$43.04	$45.47	$39.01	$36.48	$36.26	$36.08
-3%, 11000 BTU (KY)	$28.91	$45.31	$48.01	$41.12	$38.48	$38.26	$38.12
Powder River Basin							
-.33%, 8400 BTU	$8.36	$15.04	$15.80	$12.86	$10.65	$10.45	$10.31
-.35%, 8800 BTU	$9.85	$16.59	$17.14	$14.35	$12.60	$12.54	$12.58
Uinta Basin							
-.5%, 11500 BTU	$29.83	$48.15	$48.99	$44.95	$41.33	$39.26	$38.57
Foreign Coal: Colombia							
- 7%, 12000 BTU	$82.03	$134.05	$140.28	$103.03	$86.78	$74.20	$66.76
-.8%, 11600 BTU	$57.85	$125.02	$130.87	$96.29	$81.26	$69.68	$62.86
Petroleum Coke							
-6%/30 HGI, 14000 BTU	$44.90	$77.03	$102.96	$85.30	$66.57	$55.43	$49.66

Year:	2014	2015	2016	2017	2018	2019
Northern Appalachia						
-1.6%, 13000 BTU	$55.90	$55.46	$55.03	$54.67	$54.23	$53.76
-1.8%, 13000 BTU	$55.21	$54.81	$54.42	$54.07	$53.67	$53.25
-2.3%, 13000 BTU	$54.17	$53.84	$53.50	$53.18	$52.84	$52.49
Central Appalachia						
-.7%, 12500 BTU	$63.79	$63.33	$63.40	$63.73	$64.01	$64.32
-.7%, 13000 BTU	$68.10	$67.60	$67.68	$68.02	$68.33	$68.66
-1.0%, 12500 BTU	$48.26	$47.68	$47.81	$47.75	$47.79	$47.74
-1.5%, 12500 BTU	$46.98	$46.81	$46.94	$47.10	$47.15	$47.17
Ohio						
-4%, 12500 BTU	$44.81	$44.74	$44.81	$44.90	$44.94	$44.93
Illinois Basin						
-3%, 11000 BTU (IL)	$35.87	$35.79	$35.78	$35.82	$35.84	$35.88
-3%, 11000 BTU (KY)	$37.95	$37.91	$37.95	$38.03	$38.08	$38.17
Powder River Basin						
-.33%, 8400 BTU	$10.20	$10.25	$10.36	$10.62	$10.87	$11.11
-.35%, 8800 BTU	$12.58	$12.73	$12.95	$13.25	$13.56	$13.90
Uinta Basin						
-.5%, 11500 BTU	$37.65	$37.04	$36.44	$36.21	$33.90	$32.06
Foreign Coal: Colombia						
- 7%, 12000 BTU	$61.52	$59.20	$59.18	$59.22	$59.19	$58.99
-.8%, 11600 BTU	$58.03	$56.01	$56.15	$56.21	$56.21	$56.09
Petroleum Coke						
-6%/30 HGI, 14000 BTU	$45.72	$44.02	$44.03	$43.98	$43.89	$43.71

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
HIGH CASE
March 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON
HIGH CASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$79.50	$101.35	$109.65	$112.15	$115.60	$109.75	$103.70	$94.80	$86.50	$78.55	$72.90	$70.10
-1.8%, 13000 BTU	$78.19	$99.60	$107.45	$109.30	$112.43	$106.51	$100.95	$92.58	$84.65	$76.71	$71.49	$68.78
-2.3%, 13000 BTU	$76.22	$96.98	$104.16	$105.03	$107.67	$101.65	$96.82	$89.26	$81.87	$73.94	$69.38	$66.81
Central Appalachia												
-.7%, 12500 BTU	$85.30	$107.60	$109.55	$11.20	$109.82	$106.54	$102.59	$100.87	$96.25	$92.58	$85.60	$79.44
-.7%, 13000 BTU	$90.90	$114.64	$116.77	$11.94	$117.05	$113.54	$109.37	$107.51	$102.61	$98.68	$91.27	$84.69
-1.0%, 12500 BTU	$81.92	$102.86	$105.00	$10.75	$104.75	$100.81	$96.60	$94.31	$89.42	$85.39	$78.57	$72.34
-1.5%, 12500 BTU	$72.31	$80.95	$76.75	$7.32	$73.33	$72.38	$71.24	$71.71	$69.48	$67.36	$63.12	$59.51
Ohio												
-4%, 12500 BTU	$70.80	$89.83	$85.29	$94.92	$96.93	$91.77	$87.58	$80.89	$74.26	$67.01	$62.93	$60.55
Illinois Basin												
-3%, 11000 BTU (IL)	$35.40	$44.00	$47.40	$48.20	$49.00	$48.70	$46.00	$44.35	$43.00	$41.35	$40.50	$39.60
-3%, 11000 BTU (KY)	$37.49	$46.21	$49.67	$50.86	$51.78	$51.52	$48.48	$46.77	$45.46	$43.72	$42.60	$41.59
Powder River Basin												
-.33%, 8400 BTU	$13.20	$15.50	$16.10	$16.35	$16.50	$16.50	$16.35	$16.00	$15.00	$14.00	$13.20	$12.00
-.35%, 8800 BTU	$14.85	$17.07	$17.58	$17.97	$17.82	$17.92	$17.68	$17.47	$16.50	$15.55	$14.80	$13.65
Uinta Basin												
-.5%, 11500 BTU	$44.10	$48.54	$51.15	$52.00	$52.00	$51.35	$50.15	$49.10	$48.50	$48.00	$47.00	$46.00
Foreign Coal												
-.7%, 12000 BTU	$119.59	$131.88	$142.88	$150.68	$153.17	$150.04	$141.48	$135.41	$127.86	$112.61	$100.94	$93.01
-.8%, 11600 BTU	$111.56	$123.02	$133.22	$140.49	$142.85	$139.96	$132.02	$126.39	$119.41	$105.21	$94.36	$86.98
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$59.43	$75.05	$81.92	$96.80	$108.30	$107.55	$105.91	$104.02	$100.77	$95.13	$84.03	$79.68

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.
HIGH CASE
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ANNUAL AVERAGE SPOT PF

HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$68.03	$68.88	$69.69	$70.53	$71.37	$72.26	$73.14	$74.04	$74.92	$75.81	$76.71
-1.8%, 13000 BTU	$67.45	$68.28	$69.09	$69.91	$70.75	$71.62	$72.50	$73.39	$74.27	$75.15	$76.04
-2.3%, 13000 BTU	$66.57	$67.38	$68.18	$68.99	$69.82	$70.67	$71.56	$72.43	$73.29	$74.16	$75.04
Central Appalachia											
-.7%, 12500 BTU	$82.55	$84.44	$86.39	$88.40	$90.45	$92.57	$94.32	$96.09	$97.87	$99.66	$101.49
-.7%, 13000 BTU	$88.12	$90.14	$92.24	$94.38	$96.59	$98.86	$100.74	$102.64	$104.55	$106.47	$108.44
-1.0%, 12500 BTU	$61.08	$62.20	$63.41	$64.59	$65.83	$67.07	$67.98	$68.91	$69.81	$70.75	$71.77
-1.5%, 12500 BTU	$60.38	$61.51	$62.74	$63.92	$65.17	$66.43	$67.34	$68.28	$69.20	$70.14	$71.17
Ohio											
-4%, 12500 BTU	$57.53	$60.27	$61.38	$62.57	$63.85	$65.14	$66.32	$67.50	$68.66	$69.88	$71.08
Illinois Basin											
-3%, 11000 BTU (IL)	$45.82	$46.80	$47.77	$48.75	$49.68	$50.66	$51.76	$52.89	$54.02	$55.14	$56.32
-3%, 11000 BTU (KY)	$48.79	$49.87	$50.95	$52.04	$53.09	$54.19	$55.41	$56.67	$57.92	$59.17	$60.49
Powder River Basin											
-.33%, 8400 BTU	$14.56	$15.34	$16.22	$16.93	$17.61	$18.36	$19.04	$19.80	$20.62	$21.38	$22.34
-.35%, 8800 BTU	$18.30	$19.30	$20.41	$21.35	$22.28	$23.32	$24.28	$25.34	$26.47	$27.56	$28.91
Uinta Basin											
-.5%, 11500 BTU	$39.42	$41.10	$42.85	$44.70	$46.63	$48.67	$50.80	$53.02	$55.31	$57.71	$60.26
Foreign Coal											
-.7%, 12000 BTU	$74.94	$76.02	$77.14	$78.28	$79.46	$80.67	$81.94	$83.24	$84.53	$85.85	$87.19
-.8%, 11600 BTU	$71.38	$72.46	$73.55	$74.66	$75.80	$76.98	$78.20	$79.43	$80.67	$81.92	$83.20
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$55.53	$56.29	$57.06	$57.87	$58.71	$59.59	$60.51	$61.46	$62.43	$63.42	$64.42

*QCF (QUARTERLY
COAL FORECST)- 200803*
JD Energy, Inc.
HIGH CASE
March 2008

ANNUAL AVERAGE SPOT PF
HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$53.27	$52.95	$52.61	$52.27	$51.94	$51.60	$51.27	$50.94	$50.62	$50.29	$49.97
-1.8%, 13000 BTU	$52.81	$52.48	$52.15	$51.81	$51.48	$51.15	$50.83	$50.50	$50.18	$49.86	$49.54
-2.3%, 13000 BTU	$52.13	$51.79	$51.46	$51.13	$50.81	$50.48	$50.16	$49.84	$49.52	$49.20	$48.89
Central Appalachia											
-.7%, 12500 BTU	$64.64	$64.91	$65.21	$65.51	$65.82	$66.12	$66.12	$66.12	$66.12	$66.12	$66.12
-.7%, 13000 BTU	$69.00	$69.29	$69.62	$69.95	$70.28	$70.61	$70.62	$70.63	$70.63	$70.64	$70.65
-1.0%, 12500 BTU	$47.82	$47.81	$47.86	$47.87	$47.90	$47.91	$47.65	$47.42	$47.17	$46.94	$46.76
-1.5%, 12500 BTU	$47.28	$47.29	$47.36	$47.38	$47.42	$47.45	$47.21	$46.99	$46.75	$46.54	$46.36
Ohio											
-4%, 12500 BTU	$46.05	$46.33	$46.33	$46.38	$46.46	$46.53	$46.49	$46.44	$46.39	$46.35	$46.31
Illinois Basin											
-3%, 11000 BTU (IL)	$35.88	$35.97	$36.06	$36.13	$36.15	$36.18	$36.29	$36.39	$36.49	$36.58	$36.69
-3%, 11000 BTU (KY)	$38.20	$38.33	$38.46	$38.57	$38.63	$38.70	$38.84	$38.98	$39.13	$39.26	$39.41
Powder River Basin											
-.33%, 8400 BTU	$11.40	$11.79	$12.25	$12.54	$12.81	$13.12	$13.35	$13.63	$13.93	$14.18	$14.55
-.35%, 8800 BTU	$14.33	$14.84	$15.40	$15.82	$16.22	$16.65	$17.02	$17.43	$17.89	$18.29	$18.83
Uinta Basin											
-.5%, 11500 BTU	$30.87	$31.59	$32.34	$33.13	$33.93	$34.76	$35.61	$36.48	$37.37	$38.28	$39.26
Foreign Coal: Colombia											
-.7%, 12000 BTU	$58.88	$58.43	$58.23	$58.02	$57.82	$57.62	$57.45	$57.28	$57.11	$56.95	$56.80
-.8%, 11600 BTU	$55.89	$55.70	$55.51	$55.33	$55.16	$54.99	$54.82	$54.66	$54.50	$54.35	$54.20
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$43.48	$43.27	$43.07	$42.89	$42.72	$42.56	$42.42	$42.29	$42.18	$42.08	$41.96

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
LOW CASE
March 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$59.64	$38.26	$28.06	$27.35	$27.21	$26.90	$26.50	$26.29	$26.12	$25.97	$27.08	$26.85
-1.8%, 13000 BTU	$45.85	$58.49	$37.23	$27.47	$28.82	$26.73	$26.47	$26.17	$25.98	$25.83	$25.69	$26.80	$26.60
-2.3%, 13000 BTU	$44.71	$56.76	$35.69	$26.60	$26.04	$26.02	$25.84	$25.68	$25.52	$25.39	$25.26	$26.39	$26.21
Central Appalachia													
-.7%, 12500 BTU	$46.46	$61.48	$45.93	$42.86	$39.58	$39.23	$39.75	$40.31	$40.77	$41.30	$41.88	$42.50	$43.13
-.7%, 13000 BTU	$49.50	$65.52	$48.95	$45.71	$42.28	$41.88	$42.43	$43.02	$43.52	$44.09	$44.70	$45.37	$46.03
-1.0%, 12500 BTU	$44.33	$58.94	$43.37	$39.43	$33.43	$31.79	$30.44	$30.49	$30.69	$31.02	$31.38	$31.73	$32.01
-1.5%, 12500 BTU	$40.72	$45.40	$31.57	$31.46	$30.29	$29.47	$29.38	$29.69	$30.13	$30.58	$30.96	$31.31	$31.63
Ohio													
-4%, 12500 BTU	$39.19	$52.22	$32.24	$24.12	$22.56	$21.35	$20.65	$20.60	$20.57	$20.63	$20.69	$21.77	$21.77
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$28.94	$26.46	$26.50	$26.88	$26.72	$26.57	$26.40	$26.34	$26.33	$26.34	$26.35	$26.36
-3%, 11000 BTU (KY)	$28.91	$30.48	$27.94	$27.84	$28.36	$28.20	$28.07	$27.93	$27.90	$27.92	$27.96	$27.99	$28.04
Powder River Basin													
-.33%, 8400 BTU	$8.36	$10.21	$8.83	$8.71	$9.02	$8.65	$8.36	$8.11	$8.01	$7.98	$8.00	$8.05	$8.10
-.35%, 8800 BTU	$9.85	$11.79	$10.21	$10.29	$10.68	$10.39	$10.19	$10.01	$9.95	$9.94	$9.98	$10.04	$10.13
Uinta Basin													
-.5%, 11500 BTU	$29.93	$29.25	$23.59	$21.23	$20.72	$20.86	$20.61	$20.41	$20.23	$20.07	$19.91	$19.74	$19.60
Foreign Coal													
-.7%, 12000 BTU	$62.03	$82.97	$39.13	$33.57	$32.58	$32.87	$33.13	$33.43	$33.70	$33.97	$34.31	$34.65	$34.95
-.8%, 11600 BTU	$57.85	$77.39	$36.50	$31.38	$30.51	$30.87	$31.19	$31.53	$31.88	$32.23	$32.56	$32.90	$33.23
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$46.38	$28.66	$27.88	$25.00	$24.56	$24.64	$24.84	$25.06	$25.27	$25.48	$25.69	$25.90

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
LOW CASE
March 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$58.67	$37.01	$26.63	$25.43	$24.81	$24.07	$23.26	$22.63	$22.08	$21.52	$22.01	$21.42
-1.8%, 13000 BTU	$45.85	$57.54	$36.01	$26.07	$24.95	$24.38	$23.69	$22.88	$22.37	$21.81	$21.29	$21.79	$21.22
-2.3%, 13000 BTU	$44.71	$55.84	$34.52	$25.24	$24.22	$23.73	$23.13	$22.55	$21.97	$21.45	$20.94	$21.46	$20.92
Central Appalachia													
-.7%, 12500 BTU	$46.46	$60.49	$44.42	$40.67	$36.81	$35.77	$35.57	$35.38	$35.10	$34.88	$34.71	$34.55	$34.41
-.7%, 13000 BTU	$49.60	$64.46	$47.35	$43.37	$39.32	$38.19	$37.97	$37.77	$37.47	$37.24	$37.05	$36.88	$36.73
-1.0%, 12500 BTU	$44.33	$57.99	$41.95	$37.41	$31.09	$28.99	$27.24	$26.77	$26.42	$26.20	$26.01	$25.79	$25.54
-1.5%, 12500 BTU	$40.72	$44.66	$30.54	$29.85	$28.17	$26.87	$26.29	$26.06	$25.95	$25.83	$25.65	$25.45	$25.23
Ohio													
-4%, 12500 BTU	$39.19	$51.38	$31.18	$22.88	$20.98	$19.47	$18.48	$18.09	$17.71	$17.42	$17.14	$17.69	$17.37
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$28.47	$25.60	$25.14	$25.00	$24.37	$23.77	$23.18	$22.68	$22.24	$21.83	$21.42	$21.03
-3%, 11000 BTU (KY)	$28.91	$29.98	$27.02	$26.50	$26.38	$25.71	$25.12	$24.52	$24.02	$23.58	$23.17	$22.76	$22.37
Powder River Basin													
-.33%, 8400 BTU	$8.36	$10.05	$8.54	$8.27	$8.39	$7.89	$7.48	$7.12	$6.90	$8.72	$6.63	$8.54	$6.46
-.35%, 8800 BTU	$9.85	$11.60	$8.87	$9.76	$9.93	$9.47	$9.12	$8.78	$8.57	$8.40	$8.27	$8.16	$8.08
Uinta Basin													
-.5%, 11500 BTU	$29.93	$28.78	$22.82	$20.14	$19.27	$19.02	$18.44	$17.92	$17.41	$16.95	$16.50	$16.05	$15.64
Foreign Coal: Colombia													
-.7%, 12000 BTU	$62.03	$81.63	$37.84	$31.85	$30.31	$29.98	$29.65	$29.35	$29.02	$28.69	$28.43	$28.17	$27.89
-.8%, 11600 BTU	$57.85	$76.13	$35.31	$29.77	$28.38	$28.15	$27.92	$27.68	$27.45	$27.22	$26.98	$26.75	$26.51
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$45.63	$27.72	$26.45	$23.25	$22.39	$22.05	$21.81	$21.57	$21.34	$21.11	$20.89	$20.66

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.
LOWCASE
March 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

LOWCASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$71.34	$66.16	$54.32	$47.73	$42.73	$40.60	$36.63	$33.08	$30.64	$29.11	$26.85	$25.65
-1.8%, 13000 BTU	$70.17	$64.04	$53.23	$46.52	$41.56	$39.40	$35.66	$32.31	$29.98	$28.42	$26.33	$25.17
-2.3%, 13000 BTU	$68.40	$62.35	$51.60	$44.70	$39.80	$37.60	$34.20	$31.16	$29.00	$27.40	$25.55	$24.45
Central Appalachia												
-.7%, 12500 BTU	$71.15	$63.22	$57.46	$54.10	$48.35	$46.20	$45.00	$44.15	$43.50	$43.00	$42.76	$42.20
-.7%, 13000 BTU	$75.82	$67.36	$61.24	$57.65	$51.53	$49.23	$47.97	$47.06	$46.37	$45.83	$45.58	$44.99
-1.0%, 12500 BTU	$68.33	$60.50	$55.07	$51.92	$46.12	$43.72	$42.37	$41.28	$40.41	$39.66	$39.24	$38.43
-1.5%, 12500 BTU	$60.31	$47.56	$40.26	$35.33	$32.29	$31.39	$31.25	$31.39	$31.40	$31.29	$31.52	$31.61
Ohio												
-4%, 12500 BTU	$63.54	$57.76	$47.21	$40.40	$35.83	$33.95	$30.94	$28.23	$26.31	$24.83	$23.18	$22.16
Illinois Basin												
-3%, 11000 BTU (IL)	$31.10	$29.65	$28.15	$26.85	$26.50	$26.40	$26.60	$26.35	$26.50	$26.40	$26.60	$26.50
-3%, 11000 BTU (KY)	$32.83	$31.14	$29.50	$28.33	$28.00	$27.93	$28.03	$27.79	$28.02	$27.91	$27.98	$27.83
Powder River Basin												
-.33%, 8400 BTU	$11.35	$10.90	$9.40	$9.20	$9.20	$9.10	$8.60	$8.40	$8.50	$8.40	$9.00	$8.95
-.35%, 8800 BTU	$13.00	$12.47	$10.88	$10.82	$10.62	$10.52	$9.93	$9.87	$10.00	$9.95	$10.60	$10.60
Uinta Basin												
-.5%, 11500 BTU	$33.25	$31.10	$27.40	$25.25	$24.70	$24.00	$23.20	$22.45	$21.70	$21.15	$21.20	$20.85
Foreign Coal												
-.7%, 12000 BTU	$108.53	$92.65	$73.93	$56.78	$46.73	$39.35	$36.28	$34.14	$33.73	$33.50	$33.65	$33.41
-.8%, 11600 BTU	$101.24	$86.43	$68.94	$52.94	$43.58	$36.70	$33.85	$31.87	$31.51	$31.30	$31.45	$31.25
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$53.93	$52.72	$42.39	$36.48	$33.04	$28.21	$27.16	$26.23	$26.59	$28.30	$28.01	$28.62

QCF (QUARTERLY COAL FORECST)- 200803
JD Energy, Inc.
LOW CASE
March 2008

ANNUAL AVERAGE SPOT P
LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$26.62	$26.44	$26.25	$26.06	$25.87	$25.69	$25.52	$25.34	$25.16	$24.98	$24.80
-1.8%, 13000 BTU	$26.39	$26.21	$26.02	$25.83	$25.65	$25.47	$25.30	$25.12	$24.94	$24.76	$24.58
-2.3%, 13000 BTU	$26.05	$25.87	$25.68	$25.49	$25.31	$25.14	$24.96	$24.79	$24.81	$24.43	$24.26
Central Appalachia											
-.7%, 12500 BTU	$43.75	$44.35	$44.96	$45.58	$46.22	$46.87	$47.75	$48.65	$49.55	$50.46	$51.38
-.7%, 13000 BTU	$46.70	$47.34	$48.00	$48.67	$49.35	$50.05	$51.00	$51.96	$52.93	$53.91	$54.90
-1.0%, 12500 BTU	$32.37	$32.67	$33.00	$33.30	$33.64	$33.96	$34.42	$34.89	$35.34	$35.82	$36.33
-1.5%, 12500 BTU	$32.00	$32.31	$32.65	$32.96	$33.30	$33.63	$34.09	$34.57	$35.03	$35.51	$36.03
Ohio											
-4%, 12500 BTU	$21.83	$22.44	$22.42	$22.43	$22.45	$22.47	$22.45	$22.41	$22.37	$22.33	$22.29
Illinois Basin											
-3%, 11000 BTU (IL)	$26.34	$26.39	$26.42	$26.44	$26.43	$26.43	$26.49	$26.55	$26.60	$26.63	$26.68
-3%, 11000 BTU (KY)	$28.05	$28.12	$28.17	$28.23	$28.24	$28.27	$28.36	$28.45	$28.52	$28.58	$28.65
Powder River Basin											
-.33%, 8400 BTU	$8.16	$8.30	$8.43	$8.43	$8.43	$8.44	$8.44	$8.45	$8.45	$8.46	$8.47
-.35%, 8800 BTU	$10.26	$10.44	$10.60	$10.64	$10.67	$10.72	$10.76	$10.81	$10.85	$10.90	$10.96
Uinta Basin											
-.5%, 11500 BTU	$19.49	$19.37	$19.25	$19.14	$19.04	$18.95	$18.87	$18.78	$18.69	$18.61	$18.54
Foreign Coal											
-.7%, 12000 BTU	$35.23	$35.54	$35.86	$36.17	$36.49	$36.81	$37.15	$37.48	$37.81	$38.12	$38.44
-.8%, 11600 BTU	$33.56	$33.88	$34.19	$34.50	$34.81	$35.13	$35.45	$35.77	$36.08	$36.38	$36.68
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$26.11	$26.32	$26.52	$26.74	$26.96	$27.19	$27.43	$27.68	$27.92	$28.17	$28.40

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.
LOW CASE
March 2008

ANNUAL AVERAGE SPOT P
LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$20.84	$20.33	$19.81	$19.31	$18.83	$18.35	$17.89	$17.44	$17.00	$16.57	$16.15
-1.8%, 13000 BTU	$20.66	$20.15	$19.64	$19.15	$18.66	$18.19	$17.73	$17.29	$16.85	$16.43	$16.01
-2.3%, 13000 BTU	$20.39	$19.88	$19.38	$18.89	$18.42	$17.95	$17.50	$17.06	$16.63	$16.21	$15.80
Central Appalachia											
-.7%, 12500 BTU	$34.26	$34.09	$33.93	$33.78	$33.63	$33.48	$33.48	$33.48	$33.48	$33.48	$33.48
-.7%, 13000 BTU	$36.57	$36.39	$36.23	$36.07	$35.91	$35.75	$35.75	$35.76	$35.76	$35.76	$35.77
-1.0% 12500 BTU	$25.34	$25.11	$24.91	$24.68	$24.47	$24.26	$24.13	$24.01	$23.88	$23.76	$23.67
-1.5%, 12500 BTU	$25.06	$24.84	$24.64	$24.43	$24.23	$24.02	$23.90	$23.79	$23.67	$23.56	$23.47
Ohio											
-4%, 12500 BTU	$17.10	$17.25	$16.93	$16.62	$16.34	$16.05	$15.74	$15.42	$15.11	$14.81	$14.52
Illinois Basin											
-3%, 11000 BTU (IL)	$20.63	$20.28	$19.94	$19.60	$19.23	$18.88	$18.57	$18.27	$17.97	$17.67	$17.38
-3%, 11000 BTU (KY)	$21.96	$21.61	$21.27	$20.92	$20.55	$20.20	$19.88	$19.57	$19.27	$18.96	$18.67
Powder River Basin											
-.33%, 8400 BTU	$6.39	$6.38	$6.36	$6.25	$6.14	$6.03	$5.92	$5.81	$5.71	$5.61	$5.52
-.35%, 8800 BTU	$8.03	$8.03	$8.00	$7.88	$7.76	$7.66	$7.54	$7.44	$7.33	$7.23	$7.14
Uinta Basin											
-.5%, 11500 BTU	$15.26	$14.89	$14.53	$14.19	$13.85	$13.54	$13.23	$12.92	$12.63	$12.35	$12.08
Foreign Coal: Colombia											
-.7%, 12000 BTU	$27.59	$27.32	$27.07	$26.81	$26.65	$26.29	$26.04	$25.79	$25.54	$25.29	$25.04
-.8%, 11600 BTU	$26.28	$26.04	$25.80	$25.57	$25.33	$26.09	$24.85	$24.61	$24.38	$24.14	$23.90
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$20.44	$20.23	$20.02	$19.82	$19.62	$19.42	$19.23	$19.05	$18.86	$18.69	$18.50

QCF (QUARTERLY
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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER T... Cell A14
ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER T... A67

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BUSINESS AS USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$78.93	$50.48	$41.14	$37.42	$37.73	$37.85	$37.86	$38.34	$38.78	$39.25	$39.67	$40.09
-1.8%, 13000 BTU	$45.85	$77.37	$49.13	$40.29	$36.70	$37.11	$37.30	$37.54	$37.93	$38.39	$38.86	$39.30	$39.74
-2.3%, 13000 BTU	$44.71	$75.05	$47.10	$39.00	$35.63	$36.17	$36.49	$36.89	$37.32	$37.80	$38.27	$38.74	$39.21
Central Appalachia													
-.7%, 12500 BTU	$46.46	$80.24	$57.87	$54.38	$53.33	$54.89	$56.50	$57.62	$58.45	$59.48	$60.89	$62.06	$63.50
-.7%, 13000 BTU	$49.60	$85.51	$61.68	$57.99	$56.97	$58.60	$60.32	$61.50	$62.39	$63.50	$64.78	$66.25	$67.78
-1.0%, 12500 BTU	$44.33	$76.93	$54.85	$50.03	$46.04	$44.76	$44.18	$44.05	$43.98	$44.65	$45.46	$46.32	$47.12
-1.5%, 12500 BTU	$40.72	$59.21	$39.79	$39.91	$40.82	$41.23	$41.77	$42.44	$43.20	$44.04	$44.86	$45.71	$46.57
Ohio													
-4%, 12500 BTU	$39.19	$69.01	$42.54	$35.36	$32.34	$32.85	$33.14	$33.63	$33.93	$34.39	$34.83	$35.27	$35.72
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$35.91	$32.47	$33.37	$35.44	$35.53	$35.73	$36.05	$36.39	$36.77	$37.13	$37.51	$37.90
-3%, 11000 BTU (KY)	$28.91	$37.81	$34.28	$35.18	$37.15	$37.22	$37.43	$37.77	$38.13	$38.52	$38.89	$39.28	$39.68
Powder River Basin													
-.33%, 8400 BTU	$8.36	$12.91	$10.88	$10.08	$9.98	$10.07	$10.08	$10.06	$10.11	$10.20	$10.40	$10.59	$10.76
-.35%, 8800 BTU	$9.85	$15.56	$12.30	$11.49	$11.85	$12.08	$12.22	$12.33	$12.48	$12.67	$12.91	$13.15	$13.41
Uinta Basin													
-.5%, 11500 BTU	$29.93	$38.16	$28.99	$25.54	$24.86	$24.00	$24.26	$24.59	$24.93	$25.31	$25.68	$26.05	$26.43
Foreign Coal													
-.7%, 12000 BTU	$62.03	$105.40	$65.52	$56.25	$52.13	$49.89	$49.93	$50.47	$51.00	$51.55	$52.23	$52.93	$53.60
-.8%, 11600 BTU	$57.86	$98.30	$61.13	$52.67	$48.81	$46.84	$47.02	$47.62	$48.25	$48.91	$49.57	$50.27	$50.96
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$59.59	$48.09	$46.66	$39.89	$37.26	$37.14	$37.52	$37.92	$38.35	$38.78	$39.25	$39.72

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ANNUAL AVERAGE SPOT PRICES - REAL 2007 DOLLARS PER TON

BUSINESS AS USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$77.65	$48.83	$39.03	$34.80	$34.41	$33.87	$33.33	$33.01	$32.75	$32.62	$32.25	$31.99
-1.8%, 13000 BTU	$45.86	$76.12	$47.62	$38.22	$34.14	$33.84	$33.38	$32.95	$32.66	$32.42	$32.20	$31.95	$31.71
-2.3%, 13000 BTU	$44.71	$73.83	$45.65	$37.01	$33.14	$32.89	$32.65	$32.39	$32.13	$31.92	$31.71	$31.49	$31.29
Central Appalachia													
-.7%, 12500 BTU	$46.46	$78.94	$65.98	$51.60	$49.60	$50.05	$50.57	$50.68	$50.33	$50.24	$50.29	$50.45	$50.66
-.7%, 13000 BTU	$49.50	$84.12	$59.66	$56.02	$52.99	$53.44	$53.98	$53.99	$53.72	$53.63	$53.69	$53.86	$54.08
-1.0%, 12500 BTU	$44.33	$75.68	$52.86	$47.47	$42.82	$40.82	$39.54	$38.87	$37.87	$37.71	$37.67	$37.65	$37.60
-1.5%, 12500 BTU	$40.72	$58.25	$38.48	$37.87	$37.97	$37.60	$37.38	$37.25	$37.20	$37.19	$37.17	$37.16	$37.16
Ohio													
-4%, 12500 BTU	$39.19	$67.89	$41.15	$33.55	$30.07	$29.95	$29.66	$29.44	$29.22	$29.04	$28.86	$28.68	$28.50
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$35.33	$31.40	$31.66	$32.96	$32.40	$31.97	$31.65	$31.34	$31.05	$30.77	$30.49	$30.24
-3%, 11000 BTU (KY)	$28.91	$37.20	$33.15	$33.38	$34.55	$33.94	$33.50	$33.16	$32.83	$32.53	$32.23	$31.93	$31.66
Powder River Basin													
-.33%, 8400 BTU	$8.36	$12.70	$10.53	$9.56	$9.28	$9.18	$9.00	$8.83	$8.70	$8.61	$8.62	$8.61	$8.59
-.35%, 8800 BTU	$9.85	$15.31	$11.89	$10.90	$11.02	$11.01	$10.94	$10.83	$10.74	$10.70	$10.70	$10.69	$10.70
Uinta Basin													
-.5%, 11500 BTU	$29.93	$37.54	$28.04	$24.23	$23.12	$21.89	$21.71	$21.59	$21.47	$21.38	$21.28	$21.17	$21.09
Foreign Coal: Colombia													
-.7%, 12000 BTU	$62.03	$103.69	$63.38	$53.37	$48.48	$45.49	$44.69	$44.31	$43.92	$43.54	$43.28	$43.03	$42.77
-.8%, 11600 BTU	$57.85	$96.71	$59.13	$49.88	$45.39	$42.71	$42.08	$41.80	$41.55	$41.31	$41.08	$40.87	$40.66
Petroleum Coke													
6%/30 HGI, 14000 BTU	$44.90	$58.62	$46.51	$44.27	$37.19	$33.98	$33.24	$32.93	$32.65	$32.39	$32.14	$31.91	$31.69

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JD Energy, Inc.
BUSINESS AS USUAL CASE
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ANNUAL AVERAGE SPOT P

BUSINESS AS USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$40.55	$41.14	$41.66	$42.20	$42.75	$43.32	$43.89	$44.46	$45.02	$45.58	$46.17
-1.8%, 13000 BTU	$40.23	$40.78	$41.30	$41.84	$42.38	$42.94	$43.51	$44.07	$44.63	$45.18	$45.77
-2.3%, 13000 BTU	$39.74	$40.24	$40.75	$41.29	$41.82	$42.38	$42.93	$43.49	$44.04	$44.58	$45.17
Central Appalachia											
-.7%, 12500 BTU	$64.96	$66.46	$67.96	$69.60	$71.22	$72.95	$74.75	$76.56	$78.41	$80.25	$82.15
-.7%, 13000 BTU	$69.34	$70.95	$72.56	$74.32	$76.05	$77.90	$79.83	$81.77	$83.76	$85.74	$87.77
-1.0%, 12500 BTU	$48.05	$48.85	$49.89	$50.88	$51.84	$52.86	$53.88	$54.91	$55.94	$56.98	$58.10
-1.5%, 12500 BTU	$47.51	$48.41	$49.36	$50.33	$51.32	$52.34	$53.36	$54.40	$55.44	$56.48	$57.60
Ohio											
-4%, 12500 BTU	$36.22	$36.70	$37.18	$37.68	$38.19	$38.72	$39.24	$39.77	$40.29	$40.81	$41.37
Illinois Basin											
-3%, 11000 BTU (IL)	$38.32	$38.74	$39.16	$39.59	$40.02	$40.47	$40.92	$41.37	$41.81	$42.24	$42.71
-3%, 11000 BTU (KY)	$40.12	$40.55	$40.98	$41.42	$41.87	$42.33	$42.79	$43.25	$43.70	$44.14	$44.62
Powder River Basin											
-.33%, 8400 BTU	$10.97	$11.11	$11.25	$11.39	$11.51	$11.65	$11.75	$11.87	$11.99	$12.09	$12.24
-.35%, 8800 BTU	$13.74	$13.99	$14.22	$14.46	$14.67	$14.91	$15.12	$15.35	$15.58	$15.80	$16.06
Uinta Basin											
-.5%, 11500 BTU	$26.85	$27.26	$27.67	$28.10	$28.53	$28.98	$29.43	$29.88	$30.33	$30.78	$31.26
Foreign Coal											
-.7%, 12000 BTU	$54.27	$55.01	$55.80	$56.62	$57.49	$58.40	$59.38	$60.40	$61.44	$62.52	$63.57
-.8%, 11600 BTU	$51.69	$52.44	$53.20	$54.00	$54.84	$55.73	$56.67	$57.64	$58.63	$59.66	$60.67
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$40.21	$40.73	$41.28	$41.86	$42.48	$43.14	$43.85	$44.60	$45.37	$46.19	$46.97

QCF (QUARTERLY COAL FORECST)- 200803

JD Energy, Inc.
BUSINESS AS USUAL CASE
March 2008

ANNUAL AVERAGE SPOT P
BUSINESS AS USUAL CASE

Year:	2020	2021	2022	2023	2024	2026	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$31.75	$31.62	$31.44	$31.28	$31.11	$30.94	$30.77	$30.59	$30.41	$30.24	$30.08
-1.8%, 13000 BTU	$31.50	$31.35	$31.17	$31.01	$30.84	$30.67	$30.50	$30.33	$30.15	$29.97	$29.82
-2.3%, 13000 BTU	$31.12	$30.94	$30.76	$30.60	$30.43	$30.27	$30.10	$29.93	$29.75	$29.58	$28.43
Central Appalachia											
-.7%, 12500 BTU	$50.87	$51.09	$51.30	$51.59	$51.82	$52.10	$52.40	$52.68	$52.98	$53.24	$53.52
-.7%, 13000 BTU	$54.30	$54.54	$54.77	$55.08	$55.34	$55.64	$55.96	$56.27	$56.59	$56.88	$57.18
-1.0%, 12500 BTU	$37.62	$37.63	$37.66	$37.69	$37.72	$37.76	$37.77	$37.78	$37.80	$37.80	$37.85
-1.5%, 12500 BTU	$37.20	$37.22	$37.26	$37.30	$37.34	$37.39	$37.41	$37.43	$37.46	$37.47	$37.52
Ohio											
-4%, 12500 BTU	$28.36	$28.21	$28.06	$27.93	$27.79	$27.65	$27.51	$27.37	$27.22	$27.07	$26.95
Illinois Basin											
-3%, 11000 BTU (IL)	$30.01	$29.78	$29.56	$29.34	$29.12	$28.91	$28.69	$28.47	$28.25	$28.02	$27.82
-3%, 11000 BTU (KY)	$31.42	$31.17	$30.93	$30.70	$30.46	$30.23	$30.00	$29.76	$29.52	$29.28	$29.07
Powder River Basin											
-.33%, 8400 BTU	$8.59	$8.54	$8.49	$8.44	$8.38	$8.32	$8.24	$8.17	$8.10	$8.02	$7.97
-.35%, 8800 BTU	$10.76	$10.75	$10.74	$10.71	$10.67	$10.65	$10.60	$10.56	$10.53	$10.48	$10.46
Uinta Basin											
-.5%, 11500 BTU	$21.03	$20.96	$20.89	$20.82	$20.76	$20.70	$20.63	$20.56	$20.49	$20.42	$20.36
Foreign Coal: Colombia											
-.7%, 12000 BTU	$42.50	$42.29	$42.12	$41.96	$41.83	$41.72	$41.63	$41.56	$41.51	$41.48	$41.41
-.8%, 11600 BTU	$40.48	$40.31	$40.16	$40.02	$39.91	$39.81	$39.73	$39.66	$39.61	$39.58	$39.52
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$31.49	$31.31	$31.16	$31.02	$30.91	$30.81	$30.74	$30.69	$30.66	$30.64	$30.60

COAL MONTHLY SPREADSHEET
JD Energy, Inc.
July 2nd, 2008

DIRECTORY

Cell	Item
B13	Price Tables for Coal and Petroleum Coke
T13	Coal Production
T39	Coal Demand

All prices are displayed in nominal $/short tons

Region:	Central Appalachia	Central Appalachia	Central Appalachia	Central Appalachia	Northern Appalachia	Northern Appalachia	Illinois Basin (IL)	Illinois Basin (WKY)	Powder River Basin	Powder River Basin	Uinta Basin (CO)	Petcoke (Gulf)	Petcoke (Gulf)	Petcoke (West Coast)	Colombia Basin (CO)
Market:	Physical	Physica	Physical	NYMEX	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical	Physical
SO2/mmBTU	1.2	1.6	2.3	1.6	2.5	3.0-4.0	5.45	5.45	0.8	0.8	0.9	8.6	5.7	5.7	1.4
Sulfur:	0.75%	1.00%	1.40%	1.00%	1.60%	2.30%	3.00%	3.00%	0.33%	0.35%	0.59%	6.00%	4.00%	4.00%	0.80%
BTU/lb:	12,600	12,500	12,500	12,000	13,000	13,000	11,000	11,000	8,400	8,800	11,500	14,000	14,000	14,000	11,300
Mode:	FOB Mine (CSX)	FOB Mine (CSX)	FOB Mine (CSX)	Barge-Big Sandy	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOBT	FOBT	FOBT	FOB Mine
Jan 2006	$61.79	$55.62	$49.23	$55.80	$51.05	$43.32	$27.60	$28.75	$16.00	$20.00	$38.45	$19.87	$27.67	$31.30	$41.41
Feb	$61.08	$55.62	$48.65	$56.95	$49.96	$42.23	$27.36	$29.45	$14.10	$18.15	$38.55	$24.83	$28.12	$32.66	$44.83
Mar	$60.74	$54.27	$49.03	$53.88	$47.88	$39.75	$26.86	$28.90	$12.50	$14.90	$38.35	$30.28	$30.39	$32.66	$49.84
Apr	$60.38	$52.66	$47.32	$52.89	$47.63	$40.14	$28.75	$28.75	$11.15	$14.25	$38.25	$34.25	$33.57	$34.25	$50.09
May	$58.97	$51.82	$48.48	$51.19	$46.59	$39.70	$26.40	$28.45	$10.75	$13.75	$37.90	$36.30	$37.83	$36.38	$47.72
Jun	$58.82	$50.73	$44.88	$49.75	$45.60	$39.30	$26.45	$28.50	$10.00	$12.85	$38.70	$39.70	$43.77	$36.74	$48.84
Jul	$56.55	$49.79	$44.21	$46.63	$44.36	$38.06	$26.10	$28.20	$8.95	$11.45	$36.00	$41.30	$44.45	$40.82	$47.67
Aug	$53.83	$49.95	$44.11	$47.51	$43.81	$38.31	$26.70	$28.80	$8.26	$10.45	$35.45	$38.10	$43.09	$43.09	$49.73
Sep	$52.32	$49.32	$43.96	$45.35	$44.26	$39.35	$27.10	$29.15	$7.40	$8.65	$36.05	$38.65	$43.32	$44.45	$44.68
Oct	$50.88	$47.81	$43.75	$43.12	$43.81	$39.75	$27.45	$29.45	$7.80	$9.45	$36.00	$39.35	$43.91	$41.64	$45.13
Nov	$49.45	$46.77	$43.19	$40.82	$42.92	$39.50	$27.70	$29.70	$7.80	$9.80	$34.95	$36.05	$38.78	$38.78	$45.93
Dec	$46.17	$44.11	$40.93	$41.89	$41.98	$38.16	$27.65	$29.60	$7.30	$9.15	$34.45	$38.55	$43.09	$40.37	$46.44
Jan 2007	$42.90	$40.56	$36.90	$39.55	$44.05	$41.10	$26.60	$28.50	$7.15	$8.85	$34.20	$43.18	$51.35	$46.09	$46.16
Feb	$40.80	$38.20	$34.00	$40.72	$44.25	$42.15	$28.90	$28.80	$7.35	$8.95	$33.56	$44.00	$62.45	$47.63	$47.67
Mar	$41.95	$39.90	$35.65	$41.07	$43.70	$41.95	$27.05	$29.00	$7.05	$8.60	$33.50	$44.91	$52.63	$48.76	$48.22
Apr	$43.90	$41.70	$38.00	$41.88	$45.05	$43.40	$26.65	$28.85	$7.00	$8.45	$33.55	$48.38	$52.80	$49.10	$46.89
May	$46.00	$43.00	$39.90	$43.97	$44.35	$42.35	$26.55	$28.55	$7.45	$8.85	$33.50	$48.13	$53.13	$49.94	$46.22
Jun	$45.30	$42.90	$39.75	$46.93	$44.85	$43.05	$26.20	$28.15	$8.00	$9.50	$30.45	$48.53	$53.18	$50.58	$51.06
Jul	$45.55	$43.50	$40.20	$43.88	$46.35	$44.35	$26.65	$28.50	$8.50	$10.05	$27.85	$48.53	$53.18	$51.14	$53.19
Aug	$45.80	$43.56	$40.05	$43.08	$46.65	$44.70	$27.10	$28.90	$9.05	$10.65	$28.45	$44.79	$48.28	$51.44	$54.78
Sep	$45.80	$43.80	$40.25	$44.13	$46.80	$44.85	$27.05	$28.90	$9.20	$10.70	$26.85	$41.62	$46.55	$51.65	$56.53
Oct	$50.55	$48.55	$44.70	$46.87	$48.75	$46.95	$27.65	$29.55	$9.45	$10.90	$28.90	$42.07	$46.38	$51.26	$66.66
Nov	$53.95	$52.15	$48.10	$51.82	$49.50	$48.00	$27.95	$29.80	$9.80	$11.05	$28.10	$42.07	$46.65	$56.02	$82.33
Dec	$56.15	$54.10	$51.16	$53.65	$55.05	$53.56	$27.50	$29.45	$10.30	$11.65	$26.30	$44.57	$48.42	$60.33	$88.75
Jan 2008	$60.70	$58.66	$56.75	$82.96	$62.80	$60.30	$28.05	$29.95	$10.65	$12.40	$28.85	$46.95	$51.48	$62.78	$92.19
Feb	$77.75	$74.45	$65.95	$82.50	$74.30	$71.20	$31.95	$33.85	$11.95	$14.30	$35.50	$55.11	$59.98	$65.09	$105.60
Mar	$82.75	$79.30	$73.45	$76.85	$82.45	$79.80	$35.15	$37.10	$12.10	$14.50	$38.75	$56.98	$68.40	$71.56	$102.17
Apr	$87.40	$84.25	$78.55	$89.85	$102.10	$96.20	$43.10	$45.10	$11.85	$14.40	$43.35	$59.10	$70.98	$74.84	$100.33
May	$102.40	$99.40	$91.30	$104.85	$105.25	$101.60	$49.25	$51.25	$11.80	$14.10	$51.90	$64.86	$79.29	$100.92	$112.38
Jun	$118.40	$115.00	$106.25	$119.54	$113.15	$108.40	$53.00	$54.95	$11.15	$13.25	$58.65	$74.16	$84.82	$113.67	$130.07
Jul	$161.45	$158.45	$148.95	$167.36	$158.76	$152.83	$58.00	$60.85	$10.60	$12.40	$61.40	$98.79	$113.04	$135.64	$173.45
Aug	$167.08	$164.08	$153.13	$172.80	$164.73	$158.68	$59.65	$61.45	$11.05	$12.75	$62.10	$103.69	$120.04	$142.59	$179.08
Sep	$171.34	$168.34	$157.24	$178.67	$169.09	$163.09	$60.05	$61.90	$11.80	$13.20	$62.85	$108.36	$124.86	$147.46	$183.34
Oct	$173.52	$170.52	$159.22	$179.08	$171.37	$165.42	$60.20	$62.10	$11.80	$13.56	$63.40	$110.57	$127.32	$149.72	$185.52
Nov	$171.97	$169.02	$157.57	$177.25	$169.67	$163.87	$60.50	$62.35	$11.90	$13.80	$62.90	$111.33	$128.18	$150.53	$184.02
Dec	$169.76	$167.03	$155.43	$172.98	$167.53	$161.88	$60.75	$62.60	$12.05	$13.80	$61.25	$111.58	$128.08	$150.88	$182.03
Jan 2009	$167.79	$164.99	$153.19	$168.58	$165.19	$159.79	$60.75	$62.55	$12.35	$13.90	$61.00	$111.95	$127.85	$151.30	$179.89
Feb	$165.43	$162.58	$150.43	$164.57	$162.58	$157.33	$60.25	$62.05	$12.30	$13.70	$59.85	$112.76	$128.76	$152.16	$177.58
Mar	$162.40	$159.50	$147.05	$160.55	$159.40	$154.20	$59.80	$61.65	$12.00	$13.35	$56.45	$105.75	$121.85	$146.25	$174.50
Apr	$156.78	$152.83	$140.08	$152.44	$152.53	$147.48	$56.85	$60.70	$11.80	$13.20	$52.70	$94.99	$111.19	$134.54	$167.83
May	$140.01	$136.91	$123.91	$134.47	$138.51	$131.51	$56.60	$58.50	$11.50	$12.95	$49.75	$78.60	$86.00	$119.50	$151.91
Jun	$117.84	$114.64	$101.44	$111.67	$114.19	$109.24	$53.70	$55.55	$11.20	$12.60	$46.95	$65.73	$81.53	$105.73	$129.64
Jul	$107.73	$104.48	$91.38	$102.71	$103.88	$99.03	$50.45	$52.25	$10.85	$12.20	$47.30	$59.82	$75.02	$99.77	$119.48
Aug	$102.66	$99.31	$88.26	$97.84	$98.66	$93.81	$48.20	$49.95	$10.56	$11.85	$45.65	$59.41	$74.31	$99.76	$114.31
Sep	$99.71	$96.31	$83.46	$94.17	$95.41	$90.78	$44.65	$48.40	$10.05	$11.40	$42.80	$60.15	$74.55	$100.35	$111.31
Oct	$96.27	$92.77	$80.27	$91.45	$91.72	$87.12	$42.10	$43.90	$9.30	$10.80	$39.90	$60.47	$74.27	$100.57	$107.77
Nov	$92.20	$88.60	$76.40	$89.24	$87.25	$82.90	$39.95	$41.75	$9.15	$10.65	$38.35	$60.28	$73.38	$100.28	$103.60
Dec	$86.99	$83.29	$71.49	$84.05	$81.84	$77.54	$37.30	$39.05	$9.55	$10.95	$33.45	$59.22	$71.82	$98.82	$98.29
Jan 2010	$82.15	$78.35	$66.75	$79.35	$76.40	$72.55	$35.50	$37.30	$9.75	$11.30	$31.80	$58.18	$70.28	$92.28	$93.35
Feb	$78.39	$74.49	$62.94	$74.83	$72.19	$68.59	$35.20	$37.00	$9.90	$11.30	$31.50	$57.63	$69.33	$88.79	$89.49
Mar	$73.73	$68.73	$58.63	$69.33	$66.93	$63.73	$34.45	$36.30	$9.85	$11.20	$29.50	$56.32	$67.32	$84.87	$84.73
Apr	$68.61	$64.51	$53.86	$63.46	$61.31	$58.36	$33.40	$35.25	$9.70	$11.10	$27.85	$54.50	$64.90	$80.05	$79.51
May	$63.59	$59.39	$49.34	$57.85	$55.74	$53.04	$32.85	$34.75	$9.55	$11.00	$26.00	$52.52	$62.32	$75.07	$74.38
Jun	$59.74	$55.44	$45.54	$55.52	$51.19	$48.79	$33.20	$35.05	$9.85	$11.25	$25.40	$51.20	$59.80	$70.75	$70.44
Jul	$59.50	$55.10	$44.80	$55.64	$50.40	$48.20	$33.60	$35.40	$10.20	$11.65	$25.60	$49.37	$57.17	$65.92	$66.04
Aug	$60.40	$55.90	$45.90	$56.85	$50.60	$48.70	$34.20	$35.95	$10.80	$12.10	$25.80	$48.05	$54.80	$63.25	$62.55
Sep	$58.35	$53.75	$44.40	$53.70	$48.20	$46.35	$34.00	$35.75	$10.50	$11.85	$25.50	$46.09	$53.09	$61.04	$58.42
Oct	$56.20	$51.50	$42.25	$50.44	$45.75	$43.85	$33.75	$35.55	$10.20	$11.70	$26.30	$44.07	$51.32	$58.67	$54.43
Nov	$54.10	$49.30	$40.85	$49.24	$43.25	$41.40	$33.60	$35.40	$10.25	$11.75	$25.30	$42.18	$49.48	$54.88	$50.80
Dec	$53.65	$48.65	$40.30	$49.01	$42.30	$40.50	$33.40	$35.15	$10.40	$11.80	$25.35	$40.14	$47.39	$51.34	$47.17

COAL MONTHLY SPREADSHEET
JD Energy, Inc.
July 2nd, 2008

PRODUCTION

TOTAL PRODUCTION (Millions of Tons)	Q1	Q2	Q3	Q4	Total	% Change
2006	289.1	292.4	289.8	281.4	1,162.7	2.76%
2007	285.9	285.6	285.8	288.3	1,145.6	-1.48%
2008	289.1	288.5	295.1	290.9	1,163.6	1.58%
2009	291.5	285.6	289.9	291.0	1,158.7	-0.42%
APPALACHIAN PRODUCTION	**Q1**	**Q2**	**Q3**	**Q4**	**Total**	**% Change**
2006	103.5	100.3	94.3	93.8	391.9	-1.38%
2007	99.5	95.5	91.4	91.4	377.8	-3.59%
2008	97.8	99.2	98.8	95.8	391.4	3.60%
2009	95.6	93.5	94.3	95.2	378.4	-3.09%
INTERIOR PRODUCTION	**Q1**	**Q2**	**Q3**	**Q4**	**Total**	**% Change**
2006	37.6	36.8	38.8	38.2	151.4	1.50%
2007	38.0	36.3	36.9	35.5	146.7	-3.10%
2008	35.5	39.4	39.2	38.9	153.0	4.29%
2009	38.6	37.9	38.6	38.7	153.8	0.48%
WESTERN PRODUCTION	**Q1**	**Q2**	**Q3**	**Q4**	**Total**	**% Change**
2006	148.0	155.3	156.8	159.4	619.4	5.89%
2007	148.4	153.8	157.4	161.4	621.0	0.25%
2008	156.8	149.8	157.3	156.2	619.2	-0.30%
2008	157.3	154.1	157.0	157.1	625.6	1.04%

DEMAND

Millions of Tons	2004	2005	2006	2007	2008	2009
Elec Power	1013.5	1030.8	1021.2	1039.2	1045.4	1044.2
Industrial	53.0	52.7	51.5	50.3	52.5	52.5
Coke Plants	23.7	23.4	23.0	22.7	22.7	23.4
Resident/Com.	4.1	3.7	3.7	3.9	4.1	4.1
Total Domestic	1,094.3	1,110.6	1,099.4	1,116.1	1,124.7	1,124.2
+Exports	48.0	49.9	49.6	59.2	85.1	70.1
-Imports	27.3	30.5	36.2	38.3	31.7	32.8
Stock Change	-11.5	-9.7	42.8	2.5	-14.4	-2.8
Production	1,112.1	1,131.5	1,182.7	1,145.6	1,163.6	1,158.7
Discrepancy	-8.5	-11.1	-7.3	-4.1	0.0	0.0

NOTE: Both Production and Demand numbers exclude waste coal; Electric Power consumption data includes electricty generation from all sectors including the electric, industrial and commerical sectors. Non-electricity output from both the electricty and industrial sectors are included under the industrial category.

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON
ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON
QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Northern Appalachia										
-1.5%, 13000 BTU	$25.59	$26.41	$24.85	$24.45	$26.34	$26.04	$24.94	$23.65	$24.09	$40.62
-1.8%, 13000 BTU	$25.06	$25.66	$23.48	$22.21	$22.51	$22.89	$23.58	$22.12	$23.07	$39.46
-2.3%, 13000 BTU	$22.40	$21.72	$21.48	$20.71	$21.26	$21.78	$22.54	$20.65	$22.08	$35.89
Central Appalachia										
-.7%, 12500 BTU	$24.31	$26.02	$26.75	$24.86	$28.01	$25.46	$25.97	$24.60	$24.90	$47.09
-.7%, 13000 BTU	$28.08	$27.58	$28.31	$28.80	$25.80	$25.25	$25.77	$25.15	$26.42	$50.06
-1.0%, 12500 BTU	$21.84	$24.01	$24.22	$22.84	$24.41	$24.02	$24.24	$23.29	$23.46	$44.09
-1.5%, 12500 BTU	$21.54	$22.82	$22.70	$21.72	$22.73	$23.05	$23.33	$22.07	$21.72	$38.60
Ohio										
-4%, 12500 BTU	$19.79	$21.50	$20.83	$19.38	$19.25	$18.34	$18.06	$18.41	$18.89	$26.44
Illinois Basin										
-3%, 11000 BTU (IL)	$18.93	$21.68	$19.85	$16.96	$17.71	$18.10	$18.25	$17.44	$16.83	$24.63
-3%, 11000 BTU (KY)	$20.03	$22.78	$20.95	$18.10	$19.28	$20.25	$19.90	$18.81	$17.61	$29.93
Powder River Basin										
-.33%, 8400 BTU	$3.59	$3.26	$4.34	$3.60	$3.09	$3.13	$3.36	$3.45	$3.43	$7.58
-.35%, 8800 BTU	$4.65	$4.64	$5.08	$4.68	$4.11	$4.29	$4.45	$4.42	$4.38	$9.34
Uinta Basin										
-.5%, 11500 BTU	$19.79	$19.35	$13.64	$14.05	$13.66	$15.18	$15.09	$14.18	$13.35	$20.06
Foreign Coal										
-.7%, 12000 BTU	$28.74	$26.45	$28.05	$34.31	$32.76	$31.71	$29.31	$26.35	$27.89	$36.37
-.8%, 11600 BTU						$29.61	$26.70	$24.09	$25.79	$32.94
Petroleum Coke										
-6%/30 HGI, 14000 BTU			$15.42	$12.55	$19.22	$19.39	$3.52	$1.71	$8.98	$12.73

Year:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia										
-1.5%, 13000 BTU	$30.37	$31.04	$60.27	$54.42	$45.82	$46.81	$109.29	$100.38	$56.06	$41.01
-1.8%, 13000 BTU	$29.38	$29.83	$48.89	$52.23	$43.41	$45.85	$107.07	$88.45	$55.05	$40.30
-2.3%, 13000 BTU	$27.61	$28.67	$47.91	$48.94	$38.80	$44.71	$103.75	$95.54	$53.54	$39.25
Central Appalachia										
-.7%, 12500 BTU	$29.20	$34.27	$58.62	$61.97	$55.81	$46.46	$108.30	$105.04	$84.73	$88.85
-.7%, 13000 BTU	$31.07	$38.49	$82.42	$86.01	$59.56	$49.50	$116.41	$111.98	$89.02	$60.74
-1.0%, 12500 BTU	$27.25	$32.04	$55.03	$57.49	$60.71	$44.33	$105.29	$101.83	$60.38	$48.01
-1.5%, 12500 BTU	$24.19	$28.19	$49.92	$53.18	$45.49	$40.72	$93.27	$88.15	$50.33	$43.51
Ohio										
-4%, 12500 BTU	$20.72	$23.01	$33.25	$35.88	$32.65	$39.19	$81.14	$78.23	$48.35	$35.60
Illinois Basin										
-3%, 11000 BTU (IL)	$19.71	$18.81	$28.12	$27.64	$27.01	$27.01	$50.75	$54.48	$38.12	$34.89
-3%, 11000 BTU (KY)	$23.34	$22.09	$29.18	$29.82	$28.08	$28.91	$52.65	$58.29	$39.93	$38.70
Powder River Basin										
-.33%, 8400 BTU	$4.74	$8.13	$5.23	$7.96	$10.17	$8.36	$11.77	$11.99	$11.08	$11.13
-.35%, 8800 BTU	$5.86	$8.21	$6.26	$10.09	$12.74	$9.85	$13.76	$13.40	$12.50	$12.97
Uinta Basin										
-.5%, 11500 BTU	$18.96	$17.13	$28.82	$33.11	$36.75	$29.93	$59.78	$54.61	$27.08	$25.68
Foreign Coal										
-.7%, 12000 BTU	$27.70	$33.43	$59.18	$60.12	$50.63	$62.03	$125.45	$116.01	$78.58	$54.42
-.8%, 11600 BTU	$26.04	$31.41	$55.40	$46.90	$47.22	$57.86	$117.00	$107.30	$71.58	$50.95
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$8.57	$13.03	$11.27	$17.60	$34.76	$44.90	$98.62	$58.65	$50.02	$40.71

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON

BASE CASE

Year:	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Northern Appalachia										
-1.6%, 13000 BTU	$39.16	$36.49	$33.62	$32.42	$34.28	$33.32	$31.57	$29.51	$29.41	$48.32
-1.8%, 13000 BTU	$36.42	$35.29	$31.77	$28.45	$29.29	$29.29	$29.88	$27.80	$28.17	$47.05
-2.3%, 13000 BTU	$31.66	$30.00	$29.05	$27.46	$27.87	$27.89	$28.53	$25.77	$26.93	$42.92
Central Appalachia										
-.7%, 12500 BTU	$34.35	$35.95	$36.18	$32.96	$33.84	$32.58	$32.88	$30.57	$30.40	$56.15
-.7%, 13000 BTU	$36.85	$38.08	$38.30	$35.26	$33.57	$33.32	$32.61	$31.38	$32.28	$59.69
-1.0%, 12500 BTU	$31.01	$33.17	$32.76	$30.28	$31.77	$30.75	$30.68	$29.07	$28.64	$52.58
-1.5%, 12600 BTU	$30.44	$31.67	$30.70	$28.79	$29.58	$29.50	$28.64	$27.54	$26.52	$45.91
Ohio										
-4%, 12500 BTU	$27.87	$29.70	$28.17	$24.36	$23.76	$23.47	$22.85	$22.97	$23.06	$31.63
Illinois Basin										
-3%, 11000 BTU (IL)	$25.75	$29.94	$26.85	$22.48	$23.05	$23.17	$23.10	$21.76	$20.55	$29.37
-3%, 11000 BTU (KY)	$28.30	$31.46	$28.34	$24.00	$25.10	$25.92	$25.19	$23.47	$21.38	$35.69
Powder River Basin										
-.33%, 8400 BTU	$5.06	$4.51	$5.87	$4.77	$4.02	$4.00	$4.24	$4.30	$4.18	$9.03
-.35%, 8800 BTU	$6.47	$6.41	$6.67	$6.20	$5.36	$6.48	$5.63	$6.52	$5.34	$11.13
Uinta Basin										
-.5%, 11500 BTU	$27.97	$26.73	$18.46	$18.63	$17.68	$19.42	$18.10	$17.67	$18.30	$23.92
Foreign Coal: Colombia										
-.7%, 12000 BTU	$40.61	$36.54	$37.95	$45.49	$42.63	$40.59	$37.10	$32.88	$34.05	$42.18
-.8%, 11600 BTU						$37.90	$33.80	$30.06	$31.49	$39.28
Petroleum Coke										
-8%/30 HGI, 14000 BTU			$20.86	$16.64	$23.71	$24.82	$4.45	$2.13	$12.19	$15.16
IMPLICIT PRICE DEFLATOR (GDP)	86.40	88.39	90.27	92.10	93.85	95.41	96.47	97.86	100.00	102.40
% Change	2.77%	2.30%	2.12%	2.04%	1.89%	1.67%	1.11%	1.44%	2.18%	2.40%

Year:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Appalachia										
-1.6%, 13000 BTU	$35.59	$35.62	$58.08	$58.81	$48.00	$47.57	$109.29	$38.34	$53.88	$38.84
-1.8%, 13000 BTU	$34.43	$34.23	$54.54	$56.44	$45.48	$46.79	$107.07	$86.44	$52.82	$37.98
-2.3%, 13000 BTU	$32.24	$32.90	$53.44	$52.88	$41.69	$46.62	$103.78	$83.59	$51.47	$38.98
Central Appalachia										
-.7%, 12500 BTU	$34.22	$39.33	$65.39	$68.67	$58.57	$47.41	$108.30	$102.90	$62.23	$53.57
-.7%, 13000 BTU	$38.41	$41.88	$69.63	$71.33	$62.40	$50.62	$116.41	$108.68	$66.36	$57.23
-1.0%, 12500 BTU	$31.94	$38.77	$61.39	$62.12	$53.12	$45.24	$105.29	$99.75	$58.06	$46.24
-1.5%, 12600 BTU	$28.35	$33.50	$55.68	$57.47	$47.65	$41.56	$93.27	$86.35	$48.39	$41.00
Ohio										
-4%, 12500 BTU	$24.29	$28.41	$37.10	$38.77	$34.09	$39.89	$81.14	$76.63	$46.49	$33.55
Illinois Basin										
-3%, 11000 BTU (IL)	$23.10	$22.61	$29.14	$29.76	$28.29	$27.56	$50.75	$53.37	$36.65	$32.87
-3%, 11000 BTU (KY)	$27.35	$25.33	$32.55	$32.22	$30.44	$29.50	$52.65	$55.14	$39.38	$34.68
Powder River Basin										
-.33%, 8400 BTU	$5.55	$5.88	$5.83	$8.60	$10.65	$8.53	$11.77	$11.75	$10.86	$10.48
-.35%, 8800 BTU	$5.86	$7.13	$6.99	$10.90	$13.34	$10.05	$13.78	$13.12	$12.01	$12.22
Uinta Basin										
-.5%, 11500 BTU	$19.87	$19.65	$29.92	$35.77	$38.61	$30.54	$59.78	$53.50	$28.03	$24.20
Foreign Coal: Colombia										
-.7%, 12000 BTU	$32.40	$38.38	$68.02	$64.18	$52.93	$63.30	$125.45	$112.67	$73.63	$51.27
-.8%, 11600 BTU	$30.51	$39.05	$61.80	$50.68	$49.47	$59.03	$117.00	$105.11	$68.80	$48.01
Petroleum Coke										
-8%/30 HGI, 14000 BTU	$10.04	$14.95	$12.58	$18.91	$36.41	$46.82	$66.62	$57.46	$48.09	$38.36
IMPLICIT PRICE DEFLATOR (GDP)	104.19	106.40	109.46	113.00	116.57	119.66	122.11	124.65	127.01	129.59
% Change	1.75%	2.13%	2.87%	3.23%	3.16%	2.86%	2.04%	2.08%	1.89%	2.03%

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
[illegible]
August 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

[illegible]

Year: / Quarter:	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Northern Appalachia										
-1.6%, 13000 BTU	$24.73	$24.68	$26.27	$24.93	$26.76	$27.41	$26.76	$25.67	$25.77	$26.84
-1.8%, 13000 BTU	$22.16	$22.10	$23.29	$22.10	$22.35	$22.30	$22.40	$22.30	$23.05	$23.79
-2.3%, 13000 BTU	$20.96	$20.87	$21.81	$20.91	$21.21	$21.11	$21.21	$21.16	$22.01	$22.80
Central Appalachia										
-.7%, 12500 BTU	$24.95	$24.70	$25.71	$24.80	$26.86	$26.97	$27.17	$24.55	$24.50	$25.60
-.7%, 13000 BTU	$28.49	$28.23	$25.80	$24.30	$26.65	$28.75	$26.95	$24.35	$24.30	$25.40
-1.0%, 12500 BTU	$22.82	$22.81	$24.11	$23.54	$24.80	$25.10	$25.21	$23.58	$23.33	$23.98
-1.5%, 12500 BTU	$21.61	$21.46	$22.50	$21.56	$23.44	$23.44	$23.54	$23.13	$22.40	$23.13
Ohio										
-4%, 12500 BTU	$18.36	$18.25	$18.25	$18.20	$18.30	$18.25	$18.40	$18.30	$18.35	$19.30
Illinois Basin										
-3%, 11000 BTU (IL)	$16.70	$ 16.85	$ 17.80	$ 17.35	$ 18.00	$ 18.00	$18.00	$18.00	$18.15	$18.25
-3%, 11000 BTU (KY)	$17.80	$ 18.10	$ 18.75	$ 18.50	$ 19.90	$ 20.00	$21.00	$20.05	$20.00	$19.95
Powder River Basin										
-.33%, 8400 BTU	$3.40	$3.30	$3.20	$3.15	$3.00	$3.00	$3.00	$3.00	$3.20	$3.30
-.35%, 8800 BTU	$4.45	$4.40	$4.25	$4.20	$4.00	$4.00	$4.00	$4.05	$4.60	$4.60
Uinta Basin										
-.5%, 11500 BTU	$14.20	$14.00	$13.50	$13.20	$13.80	$14.00	$14.40	$15.05	$15.85	$15.60
Foreign Coal										
-.7%, 12000 BTU	$34.20	$34.50	$33.65	$32.15	$32.00	$33.25	$33.50	$32.40	$30.95	$30.00
-.8%, 11600 BTU							$31.54	$30.51	$28.69	$27.71
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$10.28	$11.79	$15.88	$17.24	$19.35	$20.41	$21.47	$21.02	$19.81	$15.27

Year: / Quarter:	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Northern Appalachia										
-1.6%, 13000 BTU	$25.72	$24.63	$24.83	$24.78	$24.48	$23.54	$23.28	$23.34	$22.90	$22.85
-1.8%, 13000 BTU	$23.79	$23.29	$23.84	$23.44	$22.80	$21.66	$21.41	$22.60	$22.03	$22.00
-2.3%, 13000 BTU	$22.60	$22.25	$22.80	$22.30	$21.51	$19.73	$19.92	$21.46	$21.11	$20.86
Central Appalachia										
-.7%, 12500 BTU	$25.64	$25.27	$26.28	$26.71	$25.91	$24.14	$23.89	$24.04	$23.54	$23.39
-.7%, 13000 BTU	$25.43	$25.07	$26.07	$26.50	$25.70	$23.95	$25.46	$25.60	$24.86	$24.78
-1.0%, 12500 BTU	$24.06	$23.33	$24.48	$25.10	$24.32	$23.13	$22.82	$22.81	$22.34	$22.19
-1.5%, 12500 BTU	$23.18	$22.81	$23.33	$24.01	$23.13	$22.03	$21.82	$21.30	$20.73	$20.83
Ohio										
-4%, 12500 BTU	$19.30	$18.10	$18.10	$17.70	$18.35	$18.00	$18.40	$18.90	$19.00	$18.25
Illinois Basin										
-3%, 11000 BTU (IL)	$18.25	$17.85	$ 18.20	$ 18.60	$18.10	$17:50	$17.15	$17.00	$16.75	$16.70
-3%, 11000 BTU (KY)	$20.05	$19.35	$ 20.00	$ 20.20	$19.75	$19.00	$18.45	$18.05	$17.20	$16.95
Powder River Basin										
-.33%, 8400 BTU	$3.62	$3.35	$3.15	$3.27	$3.38	$3.45	$3.47	$3.50	$3.40	$3.20
-.35%, 8800 BTU	$4.80	$4.45	$4.20	$4.34	$4.38	$4.45	$4.40	$4.45	$4.40	$4.20
Uinta Basin										
-.5%, 11500 BTU	$15.25	$15.20	$ 15.10	$ 14.80	$14.85	$14.40	$14.10	$13.50	$12.75	$12.80
Foreign Coal										
-.7%, 12000 BTU	$29.20	$29.00	$30.15	$28.90	$28.40	$28.00	$24.60	$24.40	$26.00	$27.25
-.8%, 11600 BTU	$25.61	$28.09	$27.99	$26.13	$25.63	$24.63	$23.34	$22.75	$24.13	$25.21
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$7.41	$3.93	$1.36	$1.36	$1.36	$1.36	$1.36	$2.75	$5.58	$5.73

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
[illegible]
August 2008

ANNUAL AVERAGE SPOT
BASE CASE [illegible]

Year:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia																			
-1.6%, 13000 BTU	$40.46	$40.62	$40.76	$41.25	$41.81	$42.47	$43.15	$43.90	$44.70	$45.69	$46.51	$47.37	$48.20	$49.01	$49.88	$50.76	$51.64	$52.51	$53.40
-1.8%, 13000 BTU	$39.84	$40.08	$40.34	$40.84	$41.42	$42.09	$42.78	$43.58	$44.38	$45.29	$46.10	$46.96	$47.78	$48.58	$49.42	$50.32	$51.19	$52.05	$52.94
-2.3%, 13000 BTU	$38.91	$39.27	$39.70	$40.24	$40.84	$41.51	$42.22	$43.04	$43.90	$44.69	$45.50	$46.34	$47.15	$47.94	$48.77	$49.66	$50.52	$51.37	$52.24
Central Appalachia																			
-.7%, 12500 BTU	$59.48	$60.96	$62.60	$64.03	$63.36	$63.77	$64.65	$66.30	$68.03	$69.88	$71.77	$73.91	$76.11	$79.24	$82.59	$85.18	$87.81	$90.43	$93.05
-.7%, 13000 BTU	$63.60	$65.08	$66.83	$68.34	$67.63	$68.08	$68.90	$70.77	$72.62	$74.60	$76.62	$78.91	$81.28	$84.63	$88.20	$90.98	$93.81	$96.61	$99.42
-1.0%, 12500 BTU	$48.21	$47.70	$47.36	$48.20	$47.56	$47.60	$48.19	$49.22	$50.34	$51.48	$52.68	$54.00	$55.39	$57.41	$59.52	$61.09	$62.64	$64.19	$65.80
-1.5%, 12500 BTU	$44.68	$46.39	$46.11	$47.33	$46.91	$47.15	$47.54	$48.63	$49.76	$50.91	$52.12	$53.45	$54.84	$56.88	$58.88	$60.53	$62.08	$63.64	$65.24
Ohio																			
-4%, 12500 BTU	$35.32	$35.86	$36.07	$36.57	$37.13	$37.76	$38.43	$39.19	$39.89	$40.74	$41.49	$42.28	$43.04	$43.78	$44.56	$45.39	$46.20	$47.00	$47.82
Illinois Basin																			
-3%, 11000 BTU (IL)	$35.09	$35.32	$35.67	$36.02	$36.40	$36.79	$37.22	$37.74	$38.31	$38.80	$39.29	$39.79	$40.29	$40.70	$41.16	$41.67	$42.14	$42.60	$43.07
-3%, 11000 BTU (KY)	$36.91	$37.20	$37.61	$38.02	$38.45	$38.89	$39.38	$39.96	$40.58	$41.14	$41.69	$42.25	$42.77	$43.28	$43.81	$44.36	$44.92	$45.44	$45.97
Powder River Basin																			
-.33%, 8400 BTU	$10.78	$10.61	$10.52	$10.60	$10.69	$10.93	$11.14	$11.38	$11.63	$12.02	$12.39	$12.62	$12.82	$13.02	$13.22	$13.45	$13.69	$13.87	$14.08
-.35%, 8800 BTU	$12.77	$12.75	$12.78	$12.95	$13.14	$13.41	$13.67	$14.01	$14.38	$14.88	$15.33	$15.68	$15.96	$16.26	$16.57	$16.89	$17.22	$17.54	$17.87
Uinta Basin																			
-.6%, 11500 BTU	$24.64	$25.00	$25.40	$25.79	$26.20	$26.61	$27.05	$27.57	$28.11	$28.62	$29.12	$29.65	$30.16	$30.66	$31.18	$31.73	$32.27	$32.80	$33.34
Foreign Coal																			
-.7%, 12000 BTU	$50.48	$49.17	$49.72	$50.23	$50.75	$51.41	$52.10	$52.82	$53.55	$54.31	$55.12	$55.96	$56.82	$57.70	$58.63	$59.63	$60.67	$61.73	$62.77
-.6%, 11600 BTU	$47.40	$46.30	$46.91	$47.52	$48.15	$48.79	$49.48	$50.22	$51.00	$51.77	$52.56	$53.37	$54.21	$55.06	$55.95	$56.91	$57.90	$58.91	$59.90
Petroleum Coke																			
-6%/30 HGI, 14000 BTU	$36.37	$34.66	$35.07	$35.47	$35.89	$36.33	$36.82	$37.35	$37.92	$38.49	$39.03	$39.64	$40.29	$40.96	$41.66	$42.46	$43.28	$44.13	$44.95

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
[redacted]
August 2008

ANNUAL AVERAGE SPOT

BASE CASE [redacted]

Year:	[redacted]																		
Northern Appalachia																			
-1.6%, 13000 BTU	$37.33	$36.74	$38.17	$35.90	$35.71	$35.60	$35.48	$35.39	$36.31	$35.41	$35.38	$36.37	$35.33	$36.28	$36.24	$38.22	$35.18	$36.12	$38.08
-1.8%, 13000 BTU	$36.76	$36.26	$35.79	$36.55	$35.38	$35.28	$35.17	$35.11	$35.06	$35.11	$35.07	$35.06	$35.02	$34.97	$34.93	$34.81	$34.87	$34.82	$34.77
-2.3%, 13000 BTU	$35.91	$35.62	$35.23	$35.02	$34.88	$34.79	$34.72	$34.69	$34.68	$34.64	$34.61	$34.60	$34.56	$34.51	$34.46	$34.45	$34.41	$34.36	$34.31
Central Appalachia																			
-.7%, 12500 BTU	$54.88	$55.16	$55.64	$55.73	$54.11	$53.46	$53.08	$53.45	$53.76	$54.17	$54.90	$55.18	$55.79	$57.04	$58.37	$59.10	$59.81	$60.48	$61.12
-.7%, 13000 BTU	$58.59	$58.87	$59.29	$58.49	$57.78	$57.08	$56.65	$57.05	$57.38	$57.82	$58.29	$58.92	$59.57	$60.91	$62.35	$63.13	$63.89	$64.62	$65.30
-1.0%, 12500 BTU	$44.48	$43.15	$42.02	$41.96	$40.64	$40.06	$39.62	$39.68	$39.77	$39.90	$40.07	$40.32	$40.60	$41.32	$42.07	$42.38	$42.66	$42.93	$43.22
-1.5%, 12500 BTU	$41.23	$41.08	$40.91	$41.19	$40.07	$39.62	$39.09	$39.21	$39.32	$39.48	$39.65	$39.90	$40.19	$40.92	$41.67	$42.00	$42.29	$42.67	$42.86
Ohio																			
-4%, 12500 BTU	$32.59	$32.26	$32.00	$31.83	$31.72	$31.65	$31.60	$31.59	$31.60	$31.58	$31.59	$31.56	$31.54	$31.51	$31.50	$31.49	$31.47	$31.44	$31.41
Illinois Basin																			
-3%, 11000 BTU (IL)	$32.37	$31.96	$31.65	$31.36	$31.09	$30.84	$30.61	$30.43	$30.27	$30.07	$29.89	$29.71	$29.50	$29.29	$29.10	$28.91	$28.70	$28.49	$28.29
-3%, 11000 BTU (KY)	$34.06	$33.86	$33.37	$33.09	$32.84	$32.60	$32.38	$32.21	$32.09	$31.88	$31.71	$31.54	$31.35	$31.15	$30.96	$30.78	$30.59	$30.39	$30.20
Powder River Basin																			
-.33%, 8400 BTU	$9.95	$9.69	$9.34	$9.23	$9.13	$9.16	$9.16	$9.18	$9.19	$9.32	$9.42	$9.42	$9.40	$9.37	$9.36	$9.33	$9.30	$9.27	$9.25
-.36%, 8800 BTU	$11.78	$11.63	$11.34	$11.27	$11.22	$11.24	$11.24	$11.29	$11.36	$11.63	$11.66	$11.69	$11.70	$11.70	$11.71	$11.72	$11.73	$11.73	$11.74
Uinta Basin																			
-.5%, 11500 BTU	$22.74	$22.62	$22.54	$22.46	$22.38	$22.30	$22.24	$22.22	$22.21	$22.18	$22.15	$22.14	$22.10	$22.07	$22.04	$22.01	$21.98	$21.94	$21.90
Foreign Coal: Colombia																			
-.7%, 12000 BTU	$45.58	$44.49	$44.11	$43.72	$43.34	$43.09	$42.84	$42.68	$42.31	$42.10	$41.93	$41.78	$41.64	$41.53	$41.44	$41.38	$41.33	$41.29	$41.23
-.8%, 11600 BTU	$43.74	$41.89	$41.62	$41.36	$41.12	$40.90	$40.68	$40.48	$40.30	$40.13	$39.98	$39.85	$39.73	$39.63	$39.56	$39.48	$39.44	$39.40	$39.35
Petroleum Coke																			
-6%/30 HGI, 14000 BTU	$33.56	$31.39	$31.12	$30.87	$30.65	$30.45	$30.27	$30.11	$29.96	$29.83	$29.69	$29.59	$29.53	$29.49	$29.46	$29.48	$29.48	$29.52	$29.52
IMPLICIT PRICE DEFLATOR (GDP)	132.33	134.98	137.63	140.29	142.97	145.68	148.61	151.47	154.55	157.54	160.52	163.56	166.61	169.65	172.78	176.00	179.27	182.56	185.90
% Change	2.11%	2.00%	1.97%	1.93%	1.91%	1.90%	1.94%	1.99%	2.03%	1.93%	1.89%	1.88%	1.87%	1.83%	1.83%	1.87%	1.86%	1.83%	1.83%

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BASE CASE
August 2008

QUARTERLY SPOT PRICE

Year: / Quarter:																						
Northern Appalachia																						
-1.6%, 13000 BTU	$24.38	$26.12	$32.88	$42.38	$43.81	$42.92	$38.34	$29.34	$29.09	$27.70	$28.20	$30.88	$31.57	$33.50	$41.24	$46.53	$52.70	$61.82	$58.60	$64.24	$53.91	$52.95
-1.8%, 13000 BTU	$23.59	$24.66	$31.91	$41.26	$42.81	$41.86	$34.32	$28.36	$28.09	$26.73	$27.01	$28.66	$30.41	$32.23	$40.04	$44.46	$51.30	$59.78	$55.15	$52.33	$51.52	$49.91
-2.3%, 13000 BTU	$22.56	$23.59	$29.39	$37.07	$39.40	$38.11	$31.57	$26.61	$26.66	$25.18	$25.82	$28.50	$29.34	$31.03	$39.12	$43.84	$50.32	$58.33	$52.98	$49.48	$47.94	$45.35
Central Appalachia																						
-.7%, 12500 BTU	$24.66	$28.02	$46.72	$61.11	$49.19	$41.33	$30.14	$27.67	$29.23	$29.74	$32.38	$34.02	$33.87	$36.84	$49.82	$56.75	$62.95	$65.15	$62.36	$63.07	$50.38	$62.08
-.7%, 13000 BTU	$26.17	$29.77	$49.66	$64.33	$62.31	$43.93	$32.07	$29.43	$31.12	$31.65	$34.44	$38.21	$36.07	$39.24	$52.84	$60.43	$67.05	$69.37	$66.41	$57.18	$64.32	$66.12
-1.0%, 12500 BTU	$22.92	$26.35	$43.07	$48.65	$46.89	$38.75	$28.18	$25.94	$27.24	$27.66	$29.43	$31.77	$31.93	$35.06	$47.99	$54.08	$58.30	$59.76	$57.71	$58.20	$59.23	$58.81
-1.5%, 12500 BTU	$21.04	$24.48	$34.68	$43.65	$41.15	$34.53	$24.22	$22.86	$24.53	$25.16	$28.93	$28.85	$28.98	$32.03	$44.34	$49.69	$53.05	$52.61	$53.50	$54.88	$52.78	$51.69
Ohio																						
-4%, 12500 BTU	$18.75	$19.55	$23.95	$28.86	$27.86	$27.10	$22.34	$20.15	$20.45	$18.98	$21.40	$22.96	$23.36	$24.35	$28.09	$28.78	$35.38	$40.77	$36.73	$35.18	$35.75	$35.86
Illinois Basin																						
-3%, 11000 BTU (IL)	$16.80	$17.05	$22.05	$25.35	$26.66	$25.45	$21.90	$19.80	$18.50	$18.65	$18.80	$19.55	$19.80	$20.50	$22.55	$25.07	$28.80	$30.08	$27.82	$27.22	$27.75	$27.88
-3%, 11000 BTU (KY)	$17.46	$18.45	$24.30	$31.45	$32.10	$31.85	$27.80	$22.60	$21.50	$21.45	$21.45	$21.86	$22.10	$22.88	$24.86	$28.05	$30.60	$33.20	$30.03	$28.25	$29.83	$30.15
Powder River Basin																						
-.33%, 8400 BTU	$3.40	$3.70	$6.25	$10.65	$7.05	$6.35	$4.65	$4.70	$4.65	$4.95	$5.00	$4.80	$6.25	$5.45	$5.55	$5.43	$6.00	$4.93	$5.18	$6.35	$7.72	$12.57
-.35%, 8800 BTU	$4.35	$4.66	$7.90	$12.75	$8.70	$8.00	$6.85	$5.75	$5.75	$6.05	$6.00	$5.80	$6.30	$6.65	$6.58	$6.43	$6.02	$6.02	$6.33	$7.98	$10.09	$18.00
Uinta Basin																						
-.5%, 11500 BTU	$13.30	$14.55	$18.06	$19.86	$20.68	$20.80	$18.40	$16.30	$16.45	$16.66	$16.15	$16.90	$17.15	$18.30	$22.42	$25.95	$29.42	$29.60	$28.88	$31.12	$34.62	$37.60
Foreign Coal																						
-.7%, 12000 BTU	$27.85	$30.46	$36.10	$36.90	$36.85	$32.62	$29.81	$27.64	$25.08	$28.38	$28.55	$28.04	$35.00	$42.12	$46.23	$54.38	$68.50	$67.62	$67.64	$49.08	$51.92	$41.84
-.8%, 11800 BTU	$25.63	$28.20	$32.60	$34.32	$34.31	$30.62	$27.99	$25.96	$23.57	$26.83	$26.83	$26.40	$32.86	$39.65	$43.28	$50.57	$64.08	$63.25	$63.92	$45.94	$48.57	$39.17
Petroleum Coke																						
6%/30 HGI, 14000 BTU	$8.83	$19.78	$18.11	$14.62	$9.96	$8.24	$7.44	$6.78	$7.97	$13.08	$20.35	$14.53	$9.52	$8.71	$6.60	$6.46	$14.71	$20.48	$22.76	$13.25	$12.02	$21.98

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

[illegible]

August 2008

QUARTERLY SPOT PRICE

[illegible]

Year:	2006				2007				2008	
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Northern Appalachia										
-1.6%, 13000 BTU	$49.63	$46.60	$44.14	$42.90	$44.00	$44.75	$46.60	$51.10	$73.12	$106.83
-1.8%, 13000 BTU	$46.48	$43.85	$41.82	$41.40	$43.08	$44.02	$46.83	$50.48	$72.02	$104.93
-2.3%, 13000 BTU	$41.76	$39.72	$38.58	$39.14	$41.73	$42.83	$44.67	$49.50	$70.37	$102.07
Central Appalachia										
-.7%, 12500 BTU	$61.21	$58.39	$54.23	$48.82	$41.92	$44.73	$45.66	$63.66	$73.73	$102.73
-.7%, 13000 BTU	$65.20	$63.26	$57.79	$52.01	$44.66	$47.66	$48.65	$57.08	$78.88	$108.48
-1.0%, 12500 BTU	$55.10	$51.81	$49.69	$48.23	$39.56	$42.53	$43.66	$51.60	$70.90	$99.55
-1.5%, 12500 BTU	$48.97	$46.25	$44.09	$42.62	$36.52	$39.22	$40.17	$47.98	$65.06	$92.03
Ohio										
-4%, 12500 BTU	$34.63	$32.93	$30.87	$32.24	$35.46	$37.43	$38.63	$45.23	$65.68	$80.68
Illinois Basin										
-3%, 11000 BTU (IL)	$27.27	$25.53	$28.83	$27.80	$28.85	$26.53	$28.93	$27.73	$31.72	$48.45
-3%, 11000 BTU (KY)	$28.37	$28.57	$28.72	$29.58	$29.77	$29.52	$28.77	$29.60	$33.63	$50.43
Powder River Basin										
-.33%, 8400 BTU	$14.20	$10.63	$8.20	$7.63	$7.18	$7.48	$8.92	$9.85	$11.57	$11.53
-.35%, 8800 BTU	$17.68	$13.62	$10.18	$9.47	$8.80	$8.93	$10.47	$11.20	$13.73	$13.92
Uinta Basin										
-.5%, 11500 BTU	$38.45	$37.62	$35.83	$35.13	$33.76	$32.50	$27.02	$26.43	$34.37	$50.63
Foreign Coal										
-.7%, 12000 BTU	$48.83	$52.74	$50.93	$49.61	$51.13	$52.48	$59.37	$85.13	$107.74	$124.32
-.8%, 11600 BTU	$45.68	$49.24	$47.65	$46.32	$47.70	$48.95	$55.37	$79.38	$100.60	$116.97
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$24.99	$36.76	$38.32	$37.98	$44.03	$47.68	$44.98	$42.90	$53.01	$68.04

Year:			2009				2010			
Quarter:	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia										
-1.6%, 13000 BTU	$135.23	$121.97	$117.60	$108.58	$92.97	$92.49	$71.84	$56.08	$49.73	$46.57
-1.8%, 13000 BTU	$131.76	$119.58	$115.38	$108.58	$91.07	$90.75	$70.42	$55.01	$48.94	$45.83
-2.3%, 13000 BTU	$126.82	$116.03	$112.22	$103.58	$88.22	$78.14	$69.29	$53.40	$47.75	$44.72
Central Appalachia										
-.7%, 12500 BTU	$132.85	$124.07	$120.32	$112.05	$97.05	$90.78	$78.09	$63.98	$59.42	$57.42
-.7%, 13000 BTU	$141.39	$132.21	$128.24	$118.40	$103.46	$96.74	$83.25	$68.20	$63.35	$61.21
-1.0%, 12500 BTU	$129.65	$121.17	$117.47	$106.96	$93.72	$87.16	$74.10	$59.78	$54.92	$52.62
-1.5%, 12500 BTU	$111.25	$104.73	$102.12	$94.76	$80.72	$75.00	$62.77	$49.58	$45.03	$43.93
Ohio										
-4%, 12500 BTU	$90.76	$87.44	$86.32	$80.87	$73.76	$71.66	$61.37	$48.21	$43.31	$40.52
Illinois Basin										
-3%, 11000 BTU (IL)	$60.67	$62.15	$62.03	$57.87	$52.62	$46.62	$41.00	$37.82	$37.17	$36.48
-3%, 11000 BTU (KY)	$62.50	$64.02	$63.85	$59.73	$54.28	$47.30	$42.82	$39.68	$38.93	$38.27
Powder River Basin										
-.33%, 8400 BTU	$11.82	$12.37	$13.12	$12.50	$11.48	$10.87	$10.86	$10.70	$11.50	$11.28
-.35%, 8800 BTU	$13.52	$13.97	$14.52	$13.92	$12.62	$12.33	$12.28	$12.12	$12.83	$12.75
Uinta Basin										
-.5%, 11500 BTU	$74.12	$79.08	$73.72	$60.23	$47.93	$36.67	$30.83	$28.42	$25.63	$25.32
Foreign Coal										
-.7%, 12000 BTU	$144.00	$126.74	$123.07	$117.18	$112.62	$107.20	$98.65	$82.68	$68.89	$56.12
-.8%, 11600 BTU	$134.27	$117.25	$114.77	$109.31	$105.08	$100.05	$92.13	$77.26	$64.40	$52.48
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$78.69	$70.86	$68.94	$56.49	$52.85	$56.33	$57.37	$52.74	$47.83	$42.13

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

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ANNUAL AVERAGE CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$102.89	$89.58	$50.24	$41.98	$41.78	$41.89	$42.33	$42.89	$43.52	$44.22	$44.97	$45.80	$46.69
-1.8%, 13000 BTU	$100.86	$87.94	$49.43	$41.31	$41.20	$41.50	$41.91	$42.48	$43.12	$43.84	$44.60	$45.44	$46.32
-2.3%, 13000 BTU	$97.81	$85.48	$48.21	$40.31	$40.34	$40.76	$41.27	$41.87	$42.53	$43.26	$44.06	$44.91	$45.76
Central Appalachia													
-.7%, 12500 BTU	$105.62	$96.98	$61.76	$60.17	$62.31	$63.88	$65.10	$65.67	$65.61	$66.39	$67.69	$69.50	$71.35
-.7%, 13000 BTU	$112.58	$103.39	$65.89	$64.25	$66.52	$68.19	$69.49	$70.10	$70.03	$70.87	$72.25	$74.19	$76.17
-1.0%, 12500 BTU	$101.17	$90.77	$55.18	$49.47	$49.33	$49.10	$49.11	$49.37	$49.19	$49.61	$50.35	$51.47	$52.64
-1.5%, 12500 BTU	$87.03	$79.85	$47.59	$45.54	$46.51	$47.33	$48.05	$48.57	$48.51	$48.95	$49.72	$50.87	$52.06
Ohio													
-4%, 12500 BTU	$79.10	$69.43	$43.19	$36.58	$36.62	$37.02	$37.51	$38.07	$38.69	$39.37	$40.11	$40.91	$41.71
Illinois Basin													
-3%, 11000 BTU (IL)	$51.42	$51.57	$37.63	$36.08	$36.32	$36.62	$36.99	$37.37	$37.77	$38.21	$38.70	$39.25	$39.79
-3%, 11000 BTU (KY)	$53.56	$53.93	$39.50	$37.96	$38.24	$38.60	$39.02	$39.45	$39.91	$40.41	$40.97	$41.57	$42.18
Powder River Basin													
-.33%, 8400 BTU	$12.48	$11.88	$11.38	$11.25	$11.00	$10.90	$10.90	$11.01	$11.17	$11.41	$11.64	$11.92	$12.24
-.35%, 8800 BTU	$14.22	$13.61	$13.08	$13.25	$13.15	$13.18	$13.28	$13.48	$13.72	$14.00	$14.32	$14.71	$15.15
Uinta Basin													
-.5%, 11500 BTU	$54.94	$48.85	$26.99	$25.98	$25.64	$26.02	$26.43	$26.85	$27.27	$27.72	$28.22	$28.76	$29.30
Foreign Coal													
-.7%, 12000 BTU	$106.24	$79.42	$66.79	$53.80	$51.41	$51.02	$51.56	$52.12	$52.73	$53.43	$54.16	$54.91	$55.69
-.8%, 11600 BTU	$109.29	$97.37	$62.49	$50.46	$48.36	$48.11	$48.74	$49.38	$50.04	$50.74	$51.48	$52.26	$53.06
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$64.74	$56.44	$45.98	$39.40	$36.66	$36.00	$36.40	$36.83	$37.28	$37.76	$38.30	$38.86	$39.44

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
BASE CASE
August 2008

ANNUAL AVERAGE CONTRACT PRICES - REAL 2008 DOLLARS PER TON

BASE CASE

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern Appalachia													
-1.6%, 13000 BTU	$102.89	$87.76	$48.30	$39.56	$38.55	$37.99	$37.56	$37.33	$37.17	$37.07	$36.97	$36.92	$36.89
-1.8%, 13000 BTU	$100.86	$86.15	$47.52	$38.93	$38.02	$37.54	$37.18	$36.97	$36.83	$36.75	$36.67	$36.63	$36.60
-2.3%, 13000 BTU	$97.81	$83.74	$46.35	$37.99	$37.22	$36.88	$36.62	$36.44	$36.32	$36.26	$36.22	$36.20	$36.16
Central Appalachia													
-.7%, 12500 BTU	$105.62	$95.00	$59.38	$56.69	$57.49	$57.79	$57.76	$57.16	$56.03	$55.65	$55.65	$56.03	$56.37
-.7%, 13000 BTU	$112.58	$101.28	$63.35	$60.54	$61.38	$61.69	$61.65	$61.02	$59.81	$59.40	$59.41	$59.81	$60.18
-1.0%, 12500 BTU	$101.17	$88.92	$53.05	$46.61	$45.52	$44.42	$43.57	$42.97	$42.01	$41.58	$41.40	$41.49	$41.59
-1.5%, 12500 BTU	$87.03	$78.23	$45.76	$42.91	$42.92	$42.82	$42.63	$42.28	$41.43	$41.03	$40.88	$41.01	$41.13
Ohio													
-4%, 12500 BTU	$79.10	$68.01	$41.52	$34.47	$33.79	$33.49	$33.28	$33.13	$33.04	$33.00	$32.98	$32.98	$32.95
Illinois Basin													
-3%, 11000 BTU (IL)	$51.42	$50.52	$36.18	$33.99	$33.51	$33.13	$32.82	$32.52	$32.26	$32.02	$31.82	$31.64	$31.44
-3%, 11000 BTU (KY)	$53.56	$52.83	$37.97	$35.77	$35.29	$34.92	$34.62	$34.34	$34.09	$33.87	$33.68	$33.51	$33.32
Powder River Basin													
-.33%, 8400 BTU	$12.48	$11.64	$10.94	$10.60	$10.15	$9.86	$9.67	$9.58	$9.54	$9.56	$9.57	$9.61	$9.67
-.35%, 8800 BTU	$14.22	$13.33	$12.58	$12.49	$12.13	$11.92	$11.78	$11.73	$11.72	$11.74	$11.77	$11.85	$11.97
Uinta Basin													
-.5%, 11500 BTU	$54.94	$47.85	$25.95	$24.48	$23.65	$23.54	$23.45	$23.37	$23.29	$23.24	$23.20	$23.19	$23.15
Foreign Coal: Colombia													
-.7%, 12000 BTU	$106.24	$77.80	$64.21	$50.69	$47.44	$46.16	$45.75	$45.36	$45.04	$44.79	$44.53	$44.26	$44.00
-.8%, 11600 BTU	$109.29	$95.39	$60.07	$47.55	$44.62	$43.52	$43.24	$42.98	$42.74	$42.53	$42.33	$42.13	$41.92
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$64.74	$55.29	$44.20	$37.13	$33.83	$32.57	$32.30	$32.05	$31.84	$31.65	$31.49	$31.33	$31.16

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
BASE CASE
August 2008

QUARTERLY CONTRACT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$72.06	$108.68	$117.78	$113.06	$108.62	$94.96	$83.07	$71.68	$62.31	$50.44	$46.95	$41.25
-1.8%, 13000 BTU	$70.47	$106.55	$115.46	$110.95	$106.61	$93.20	$81.54	$70.41	$61.26	$49.62	$46.22	$40.61
-2.3%, 13000 BTU	$68.09	$103.36	$111.99	$107.79	$103.60	$90.57	$79.25	$68.51	$59.68	$48.39	$45.11	$39.85
Central Appalachia												
-.7%, 12500 BTU	$75.06	$101.89	$127.37	$118.15	$113.67	$102.43	$89.46	$82.34	$70.32	$59.22	$58.69	$58.81
-.7%, 13000 BTU	$80.00	$108.61	$135.77	$125.94	$121.18	$109.20	$95.39	$87.81	$75.01	$63.18	$62.62	$62.76
-1.0%, 12500 BTU	$70.81	$97.62	$121.38	$114.88	$105.44	$96.57	$85.90	$75.19	$63.38	$55.92	$51.56	$49.89
-1.5%, 12500 BTU	$60.95	$84.22	$103.99	$98.94	$94.23	$83.99	$75.10	$66.10	$53.80	$47.77	$44.38	$44.41
Ohio												
-4%, 12500 BTU	$62.05	$81.22	$89.24	$83.89	$78.73	$72.37	$64.44	$62.17	$54.05	$43.88	$40.93	$36.68
Illinois Basin												
-3%, 11000 BTU (IL)	$34.05	$51.36	$59.36	$60.92	$58.58	$54.64	$50.12	$42.93	$38.48	$36.27	$35.38	$35.21
-3%, 11000 BTU (KY)	$35.80	$53.32	$61.65	$63.38	$61.08	$57.10	$52.49	$45.04	$40.42	$38.12	$37.20	$37.05
Powder River Basin												
-.33%, 8400 BTU	$12.11	$12.65	$12.61	$12.56	$12.84	$12.25	$11.41	$11.01	$11.00	$10.98	$10.97	$10.90
-.35%, 8800 BTU	$14.06	$14.36	$14.26	$14.22	$14.59	$14.01	$13.11	$12.72	$12.75	$12.78	$12.82	$12.82
Uinta Basin												
-.5%, 11500 BTU	$33.12	$49.54	$68.80	$68.29	$64.28	$52.41	$44.81	$33.89	$27.56	$26.00	$25.34	$25.09
Foreign Coal												
-.7%, 12000 BTU	$88.57	$117.98	$115.91	$102.50	$89.16	$81.26	$76.83	$70.43	$64.61	$60.19	$57.18	$54.44
-.8%, 11600 BTU	$82.66	$114.70	$128.11	$111.67	$104.12	$100.11	$96.22	$89.05	$78.09	$66.65	$54.59	$50.14
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$56.16	$64.14	$72.60	$66.06	$59.46	$55.04	$55.49	$55.77	$55.53	$49.11	$43.48	$40.44

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

ANNUAL AVERAGE CONTRA

BASE CASE

Year:	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$47.63	$48.49	$49.36	$50.21	$51.07	$51.97	$52.89	$53.79	$54.71	$55.63
-1.8%, 13000 BTU	$47.21	$48.07	$48.93	$49.77	$50.63	$51.52	$52.43	$53.32	$54.23	$55.15
-2.3%, 13000 BTU	$46.59	$47.44	$48.28	$49.12	$49.96	$50.84	$51.74	$52.62	$53.52	$54.42
Central Appalachia										
-.7%, 12500 BTU	$73.32	$75.40	$77.80	$80.58	$83.79	$86.85	$89.54	$92.24	$94.97	$97.76
-.7%, 13000 BTU	$78.27	$80.51	$83.07	$86.06	$89.49	$92.77	$95.65	$98.55	$101.47	$104.46
-1.0%, 12500 BTU	$53.87	$55.18	$56.68	$58.46	$60.49	$62.38	$63.98	$65.59	$67.24	$68.94
-1.5%, 12500 BTU	$53.29	$54.61	$56.11	$57.88	$59.91	$61.80	$63.41	$65.02	$66.66	$68.35
Ohio										
-4%, 12500 BTU	$42.48	$43.27	$44.06	$44.85	$45.64	$46.46	$47.31	$48.14	$48.98	$49.82
Illinois Basin										
-3%, 11000 BTU (IL)	$40.30	$40.81	$41.30	$41.77	$42.25	$42.74	$43.24	$43.72	$44.20	$44.69
-3%, 11000 BTU (KY)	$42.75	$43.31	$43.87	$44.41	$44.95	$45.51	$46.07	$46.62	$47.17	$47.72
Powder River Basin										
-.33%, 8400 BTU	$12.61	$12.91	$13.14	$13.34	$13.55	$13.77	$13.99	$14.21	$14.43	$14.65
-.35%, 8800 BTU	$15.61	$16.01	$16.33	$16.64	$16.96	$17.29	$17.62	$17.96	$18.30	$18.67
Uinta Basin										
-.5%, 11500 BTU	$29.83	$30.36	$30.89	$31.41	$31.94	$32.49	$33.05	$33.60	$34.16	$34.73
Foreign Coal										
-.7%, 12000 BTU	$56.50	$57.35	$58.23	$59.14	$60.08	$61.09	$62.14	$63.22	$64.30	$65.36
-.8%, 11600 BTU	$53.87	$54.69	$55.55	$56.43	$57.34	$58.29	$59.30	$60.33	$61.36	$62.38
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$40.02	$40.62	$41.28	$41.96	$42.69	$43.47	$44.30	$45.15	$46.01	$46.85

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BASE CASE

August 2008

ANNUAL AVERAGE CONTRA

BASE CASE

Year:	2021	2022	2023	2024	2026	2026	2027	2028	2029	2030
Northern Appalachia										
-1.6%, 13000 BTU	$36.92	$36.89	$36.85	$36.80	$36.76	$36.73	$36.70	$36.64	$36.59	$36.54
-1.8%, 13000 BTU	$36.60	$36.57	$36.53	$36.48	$36.44	$36.42	$36.38	$36.32	$36.27	$36.22
-2.3%, 13000 BTU	$36.11	$36.09	$36.05	$36.00	$35.96	$35.94	$35.90	$35.84	$35.79	$35.75
Central Appalachia										
-.7%, 12500 BTU	$56.83	$57.36	$58.08	$59.06	$60.31	$61.39	$62.12	$62.83	$63.52	$64.21
-.7%, 13000 BTU	$60.67	$61.24	$62.02	$63.07	$64.41	$65.57	$66.36	$67.12	$67.87	$68.61
-1.0%, 12500 BTU	$41.75	$41.98	$42.32	$42.84	$43.54	$44.09	$44.39	$44.68	$44.97	$45.28
-1.5%, 12500 BTU	$41.31	$41.54	$41.89	$42.42	$43.12	$43.68	$44.00	$44.29	$44.59	$44.90
Ohio										
-4%, 12500 BTU	$32.93	$32.92	$32.90	$32.87	$32.85	$32.84	$32.82	$32.79	$32.76	$32.73
Illinois Basin										
-3%, 11000 BTU (IL)	$31.24	$31.04	$30.83	$30.62	$30.41	$30.21	$30.00	$29.78	$29.57	$29.35
-3%, 11000 BTU (KY)	$33.13	$32.95	$32.75	$32.55	$32.35	$32.17	$31.97	$31.76	$31.55	$31.35
Powder River Basin										
-.33%, 8400 BTU	$9.77	$9.82	$9.81	$9.78	$9.75	$9.73	$9.71	$9.68	$9.65	$9.62
-.35%, 8800 BTU	$12.10	$12.18	$12.20	$12.20	$12.21	$12.22	$12.23	$12.23	$12.24	$12.26
Uinta Basin										
-.5%, 11500 BTU	$23.12	$23.09	$23.06	$23.02	$22.99	$22.96	$22.93	$22.89	$22.85	$22.81
Foreign Coal: Colombia										
-.7%, 12000 BTU	$43.80	$43.63	$43.48	$43.34	$43.25	$43.18	$43.11	$43.06	$43.01	$42.93
-.8%, 11600 BTU	$41.75	$41.61	$41.47	$41.36	$41.27	$41.20	$41.14	$41.09	$41.04	$40.97
Petroleum Coke										
-6%/30 HGI, 14000 BTU	$31.02	$30.90	$30.82	$30.76	$30.73	$30.73	$30.74	$30.76	$30.78	$30.77

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
HIGH CASE
August 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$130.75	$186.80	$166.74	$137.86	$108.77	$96.29	$87.55	$82.29	$82.01	$82.72	$83.69	$84.86
-1.8%, 13000 BTU	$45.85	$128.06	$183.10	$163.80	$135.49	$107.12	$95.01	$86.64	$81.48	$81.25	$81.97	$82.97	$84.19
-2.3%, 13000 BTU	$44.71	$124.03	$177.69	$159.31	$131.94	$104.63	$93.10	$85.28	$80.27	$80.11	$80.84	$81.90	$83.19
Central Appalachia													
-.7%, 12500 BTU	$46.46	$128.57	$185.30	$163.85	$131.26	$102.12	$92.96	$94.89	$96.99	$99.23	$101.63	$104.07	$106.65
-.7%, 13000 BTU	$49.50	$137.01	$197.50	$174.73	$140.22	$109.03	$99.24	$101.29	$103.53	$105.92	$108.48	$111.08	$113.84
-1.0%, 12500 BTU	$44.33	$125.00	$179.62	$152.84	$110.84	$82.77	$72.73	$71.79	$73.02	$74.62	$76.16	$77.67	$79.18
-1.5%, 12500 BTU	$40.72	$110.72	$155.49	$127.41	$100.45	$76.72	$69.21	$69.89	$71.70	$73.47	$75.13	$76.64	$78.23
Ohio													
-4%, 12500 BTU	$39.19	$96.15	$146.94	$143.94	$119.69	$94.96	$84.53	$77.47	$72.96	$72.84	$73.54	$74.54	$75.75
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$57.65	$83.28	$84.89	$71.53	$70.82	$70.19	$69.75	$69.30	$68.88	$68.45	$68.06	$67.80
-3%, 11000 BTU (KY)	$28.91	$59.65	$86.08	$88.92	$75.29	$74.55	$73.96	$73.58	$73.17	$72.79	$72.40	$72.06	$71.84
Powder River Basin													
-.33%, 8400 BTU	$8.36	$12.43	$15.78	$14.43	$13.89	$14.26	$14.55	$14.99	$15.46	$15.95	$16.66	$17.34	$18.08
-.35%, 8800 BTU	$9.85	$14.44	$17.18	$15.84	$16.19	$16.88	$17.49	$18.20	$18.88	$19.59	$20.45	$21.28	$22.25
Uinta Basin													
-.5%, 11500 BTU	$29.93	$65.15	$101.65	$92.01	$81.10	$74.45	$69.14	$64.37	$59.71	$55.52	$56.49	$57.50	$58.55
Foreign Coal													
-.7%, 12000 BTU	$62.03	$148.93	$202.88	$193.86	$125.62	$86.67	$74.99	$75.37	$76.09	$79.48	$81.92	$84.00	$84.96
-.8%, 11600 BTU	$57.85	$138.90	$189.28	$181.16	$117.62	$81.38	$70.61	$71.10	$71.99	$75.41	$77.75	$79.77	$80.78
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$78.25	$103.85	$126.98	$93.97	$62.44	$52.90	$53.16	$53.74	$56.21	$57.90	$59.36	$60.08

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
HIGH CASE
August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON
HIGH CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$47.57	$130.75	$182.99	$160.30	$129.90	$100.37	$87.11	$77.68	$71.63	$70.05	$69.33	$68.81	$68.41
-1.8%, 13000 BTU	$46.79	$128.06	$179.37	$157.48	$127.67	$98.84	$85.96	$76.87	$70.92	$69.40	$68.70	$68.22	$67.87
-2.3%, 13000 BTU	$45.62	$124.03	$174.07	$153.16	$124.32	$96.55	$84.22	$75.66	$69.87	$68.42	$67.76	$67.34	$67.06
Central Appalachia													
-.7%, 12500 BTU	$47.41	$128.57	$181.52	$157.52	$123.68	$94.23	$84.10	$84.19	$84.42	$84.75	$85.18	$85.56	$85.98
-.7%, 13000 BTU	$50.52	$137.01	$193.47	$167.98	$132.12	$100.60	$89.78	$89.87	$90.11	$90.46	$90.93	$91.34	$91.77
-1.0%, 12500 BTU	$45.24	$125.00	$175.96	$146.94	$104.44	$76.38	$65.80	$63.69	$63.56	$63.65	$63.84	$63.87	$63.83
-1.5%, 12500 BTU	$41.55	$110.72	$152.32	$122.49	$94.65	$70.79	$62.61	$62.01	$62.40	$62.75	$62.97	$63.01	$63.07
Ohio													
-4%, 12500 BTU	$39.99	$96.15	$143.94	$138.38	$112.78	$87.63	$76.47	$68.73	$63.50	$62.21	$61.64	$61.29	$61.06
Illinois Basin													
-3%, 11000 BTU (IL)	$27.56	$57.55	$81.58	$81.61	$67.40	$65.35	$63.49	$61.89	$60.32	$58.83	$57.37	$55.96	$54.66
-3%, 11000 BTU (KY)	$29.50	$59.65	$84.32	$85.49	$70.94	$68.79	$66.91	$65.28	$63.69	$62.17	$60.68	$59.24	$57.91
Powder River Basin													
-.33%, 8400 BTU	$8.53	$12.43	$15.45	$13.87	$13.08	$13.16	$13.16	$13.30	$13.46	$13.62	$13.97	$14.26	$14.58
-.35%, 8800 BTU	$10.05	$14.44	$16.83	$15.23	$15.26	$15.58	$15.82	$16.15	$16.43	$16.73	$17.14	$17.50	$17.94
Uinta Basin													
-.5%, 11500 BTU	$30.54	$65.15	$99.58	$88.46	$76.42	$68.70	$62.55	$57.11	$51.97	$47.42	$47.35	$47.28	$47.20
Foreign Coal: Colombia													
-.7%, 12000 BTU	$63.30	$148.93	$198.75	$186.38	$118.37	$79.97	$67.84	$66.87	$66.23	$67.88	$68.66	$69.07	$68.49
-.8%, 11600 BTU	$59.03	$138.90	$185.42	$174.17	$110.83	$75.09	$63.88	$63.08	$62.66	$64.41	$65.17	$65.59	$65.12
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$45.82	$78.25	$101.73	$122.08	$88.54	$57.61	$47.86	$47.16	$46.77	$48.01	$48.53	$48.81	$48.43

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
HIGH CASE
August 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

HIGH CASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$73.12	$106.83	$168.45	$174.60	$183.25	$186.15	$190.45	$187.35	$182.45	$175.00	$161.15	$148.35
-1.8%, 13000 BTU	$72.02	$104.93	$164.11	$171.20	$179.95	$182.72	$186.56	$183.40	$178.84	$171.65	$158.58	$145.99
-2.3%, 13000 BTU	$70.37	$102.07	$157.59	$166.11	$175.01	$177.58	$180.72	$177.47	$173.43	$166.63	$154.72	$142.46
Central Appalachia												
-.7%, 12500 BTU	$73.73	$102.73	$164.85	$172.95	$181.44	$185.00	$189.40	$185.35	$179.20	$171.10	$159.15	$145.95
-.7%, 13000 BTU	$78.58	$109.46	$175.71	$184.31	$193.39	$197.15	$201.91	$197.56	$191.04	$182.37	$169.70	$155.59
-1.0%, 12500 BTU	$70.80	$99.55	$161.12	$168.91	$177.14	$179.91	$182.89	$178.00	$170.25	$159.87	$147.10	$133.75
-1.5%, 12500 BTU	$65.05	$92.03	$138.26	$146.00	$153.99	$156.46	$157.52	$153.15	$144.05	$132.59	$120.62	$111.68
Ohio												
-4%, 12500 BTU	$65.68	$80.68	$113.06	$125.17	$134.62	$138.82	$151.10	$163.22	$155.85	$150.44	$140.35	$129.10
Illinois Basin												
-3%, 11000 BTU (IL)	$31.72	$48.45	$72.55	$77.50	$80.20	$82.50	$85.75	$84.65	$85.00	$84.40	$86.00	$84.15
-3%, 11000 BTU (KY)	$33.63	$50.43	$74.72	$79.83	$82.55	$85.16	$88.63	$87.97	$88.77	$88.57	$90.09	$88.26
Powder River Basin												
-.33%, 8400 BTU	$11.57	$11.53	$13.10	$13.50	$14.85	$15.90	$16.35	$16.00	$15.50	$14.40	$14.00	$13.80
-.35%, 8800 BTU	$13.73	$13.92	$15.00	$15.10	$16.25	$17.32	$17.68	$17.47	$16.93	$15.82	$15.33	$15.27
Uinta Basin												
-.5%, 11500 BTU	$34.37	$50.63	$84.25	$91.35	$98.65	$100.45	$104.55	$102.95	$98.30	$94.45	$89.70	$85.60
Foreign Coal												
-.7%, 12000 BTU	$107.74	$124.32	$178.95	$175.28	$185.59	$193.47	$219.78	$218.91	$226.37	$221.10	$184.51	$142.64
-.8%, 11600 BTU	$100.50	$115.97	$166.86	$163.45	$173.07	$180.48	$205.08	$204.32	$211.43	$206.58	$172.49	$133.40
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$53.01	$66.04	$95.18	$98.76	$103.96	$93.27	$103.15	$115.03	$131.66	$141.03	$128.13	$107.09

QCF (QUARTERLY COAL FORECAST) - 200804
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ANNUAL AVERAGE SPOT F

HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$86.22	$88.06	$89.57	$91.14	$92.74	$94.36	$96.04	$97.82	$99.65	$101.52	$103.45
-1.8%, 13000 BTU	$85.60	$87.30	$88.79	$90.35	$91.93	$93.54	$95.20	$96.97	$98.78	$100.63	$102.55
-2.3%, 13000 BTU	$84.68	$86.15	$87.62	$89.16	$90.72	$92.31	$93.95	$95.69	$97.48	$99.31	$101.20
Central Appalachia											
-.7%, 12500 BTU	$109.36	$112.00	$114.66	$117.39	$120.15	$122.93	$125.78	$128.75	$131.78	$134.84	$137.96
-.7%, 13000 BTU	$116.74	$119.56	$122.42	$125.34	$128.30	$131.29	$134.34	$137.53	$140.77	$144.05	$147.41
-1.0%, 12500 BTU	$80.91	$82.50	$84.16	$85.77	$87.44	$89.07	$90.65	$92.33	$94.00	$95.71	$97.57
-1.5%, 12500 BTU	$79.99	$81.59	$83.27	$84.89	$86.57	$88.20	$89.79	$91.49	$93.17	$94.89	$96.74
Ohio											
-4%, 12500 BTU	$77.15	$78.52	$79.90	$81.34	$82.81	$84.29	$85.83	$87.47	$89.15	$90.86	$92.63
Illinois Basin											
-3%, 11000 BTU (IL)	$67.57	$67.22	$66.84	$66.44	$65.96	$65.43	$64.90	$64.40	$63.83	$63.20	$62.57
-3%, 11000 BTU (KY)	$71.64	$71.33	$70.97	$70.61	$70.16	$69.65	$69.14	$68.66	$68.10	$67.50	$66.88
Powder River Basin											
-.33%, 8400 BTU	$18.87	$19.71	$20.52	$21.48	$22.40	$23.34	$24.33	$25.37	$26.46	$27.59	$28.78
-.35%, 8800 BTU	$23.33	$24.40	$25.40	$26.65	$27.87	$29.15	$30.47	$31.88	$33.35	$34.90	$36.53
Uinta Basin											
-.5%, 11500 BTU	$59.65	$60.71	$61.76	$62.84	$63.91	$64.98	$66.06	$67.20	$68.34	$69.49	$70.65
Foreign Coal											
-.7%, 12000 BTU	$86.07	$87.04	$88.07	$88.88	$89.70	$89.51	$89.30	$90.14	$91.05	$92.05	$93.07
-.8%, 11600 BTU	$81.98	$82.97	$83.96	$84.77	$85.57	$85.42	$85.22	$86.02	$86.89	$87.85	$88.81
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$60.96	$61.68	$62.35	$62.96	$63.59	$63.54	$63.48	$64.18	$64.94	$65.80	$66.64

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JD Energy, Inc.
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August 2008

ANNUAL AVERAGE SPOT F
HIGH CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$68.12	$68.26	$68.14	$68.05	$67.97	$67.92	$67.88	$67.87	$67.88	$67.90	$67.95
-1.8%, 13000 BTU	$67.64	$67.66	$67.55	$67.45	$67.38	$67.33	$67.29	$67.28	$67.28	$67.31	$67.36
-2.3%, 13000 BTU	$66.91	$66.77	$66.66	$66.57	$66.49	$66.44	$66.41	$66.39	$66.40	$66.43	$66.47
Central Appalachia											
-.7%, 12500 BTU	$86.41	$86.81	$87.23	$87.64	$88.06	$88.48	$88.91	$89.33	$89.76	$90.19	$90.62
-.7%, 13000 BTU	$92.23	$92.67	$93.13	$93.58	$94.04	$94.50	$94.96	$95.42	$95.88	$96.35	$96.82
-1.0%, 12500 BTU	$63.93	$63.95	$64.02	$64.04	$64.09	$64.11	$64.07	$64.06	$64.02	$64.02	$64.09
-1.5%, 12500 BTU	$63.20	$63.24	$63.35	$63.38	$63.45	$63.49	$63.47	$63.48	$63.46	$63.47	$63.54
Ohio											
-4%, 12500 BTU	$60.95	$60.86	$60.79	$60.73	$60.69	$60.67	$60.67	$60.69	$60.72	$60.77	$60.85
Illinois Basin											
-3%, 11000 BTU (IL)	$53.39	$52.11	$50.84	$49.60	$48.34	$47.09	$45.87	$44.68	$43.47	$42.27	$41.10
-3%, 11000 BTU (KY)	$56.60	$65.29	$53.99	$52.72	$51.42	$50.13	$48.87	$47.64	$46.39	$45.15	$43.93
Powder River Basin											
-.33%, 8400 BTU	$14.91	$15.28	$15.61	$16.04	$16.41	$16.80	$17.19	$17.60	$18.02	$18.45	$18.90
-.35%, 8800 BTU	$18.43	$18.91	$19.32	$19.90	$20.43	$20.98	$21.54	$22.12	$22.72	$23.34	$24.00
Uinta Basin											
-.5%, 11500 BTU	$47.13	$47.06	$46.99	$46.91	$46.84	$46.77	$46.70	$46.62	$46.55	$46.48	$46.41
Foreign Coal: Colombia											
-.7%, 12000 BTU	$68.01	$67.47	$66.99	$66.36	$65.74	$64.43	$63.12	$62.54	$62.02	$61.57	$61.13
-.8%, 11600 BTU	$64.77	$64.31	$63.87	$63.29	$62.72	$61.48	$60.24	$59.68	$59.18	$58.76	$58.34
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$48.16	$47.81	$47.43	$47.00	$46.61	$45.74	$44.87	$44.53	$44.24	$44.01	$43.77

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
LOW CASE
August 2008

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QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON	A121

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$95.68	$49.48	$30.24	$29.04	$28.91	$28.59	$28.21	$27.99	$27.80	$27.64	$28.83	$28.62
-1.8%, 13000 BTU	$45.85	$93.75	$48.52	$29.70	$28.54	$28.47	$28.21	$27.92	$27.71	$27.54	$27.39	$28.58	$28.40
-2.3%, 13000 BTU	$44.71	$90.87	$47.09	$28.89	$27.80	$27.81	$27.64	$27.48	$27.30	$27.15	$27.01	$28.21	$28.06
Central Appalachia													
-.7%, 12500 BTU	$46.46	$93.12	$50.49	$40.76	$39.64	$39.97	$40.54	$41.12	$41.58	$42.11	$42.69	$43.33	$44.01
-.7%, 13000 BTU	$49.50	$99.23	$53.81	$43.47	$42.34	$42.67	$43.28	$43.89	$44.38	$44.95	$45.57	$46.25	$46.97
-1.0%, 12500 BTU	$44.33	$90.53	$48.94	$38.02	$33.47	$32.40	$31.72	$31.11	$31.30	$31.63	$31.99	$32.34	$32.67
-1.5%, 12500 BTU	$40.72	$80.19	$42.37	$31.70	$30.34	$30.03	$30.18	$30.28	$30.74	$31.18	$31.56	$31.91	$32.28
Ohio													
-4%, 12500 BTU	$39.19	$71.60	$38.49	$26.10	$25.21	$25.24	$25.10	$24.96	$24.81	$24.69	$24.57	$25.68	$25.55
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$46.30	$38.53	$29.13	$25.54	$25.47	$25.42	$25.45	$25.48	$25.62	$25.57	$25.63	$25.75
-3%, 11000 BTU (KY)	$28.91	$48.07	$39.81	$30.51	$26.88	$26.81	$26.79	$26.85	$26.90	$26.97	$27.04	$27.14	$27.28
Powder River Basin													
-.33%, 8400 BTU	$8.36	$10.60	$8.68	$8.71	$9.05	$8.82	$8.59	$8.42	$8.32	$8.24	$8.27	$8.30	$8.35
-.35%, 8800 BTU	$9.85	$12.51	$10.06	$10.29	$10.55	$10.44	$10.32	$10.23	$10.16	$10.13	$10.15	$10.19	$10.28
Uinta Basin													
-.5%, 11500 BTU	$29.93	$54.25	$40.67	$21.69	$19.51	$18.97	$18.46	$17.96	$17.49	$17.03	$16.60	$16.18	$15.78
Foreign Coal													
-.7%, 12000 BTU	$62.03	$107.87	$55.28	$48.23	$37.94	$33.92	$32.70	$32.66	$32.62	$33.73	$34.41	$34.97	$35.06
-.8%, 11600 BTU	$57.85	$100.60	$51.57	$45.07	$35.52	$31.85	$30.79	$30.81	$30.86	$32.00	$32.66	$33.21	$33.33
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$57.93	$28.18	$31.56	$28.38	$24.44	$23.07	$23.04	$23.04	$23.85	$24.32	$24.72	$24.79

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
LOW CASE
August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON

LOW CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$47.57	$95.68	$48.47	$29.07	$27.37	$26.68	$25.87	$25.03	$24.36	$23.74	$23.17	$23.70	$23.07
-1.8%, 13000 BTU	$46.79	$93.75	$47.54	$28.56	$26.90	$26.27	$25.52	$24.77	$24.12	$23.52	$22.96	$23.50	$22.89
-2.3%, 13000 BTU	$45.62	$90.87	$46.13	$27.77	$26.19	$25.66	$25.01	$24.38	$23.76	$23.19	$22.64	$23.19	$22.62
Central Appalachia													
-.7%, 12500 BTU	$47.41	$93.12	$49.46	$39.19	$37.35	$36.88	$36.67	$36.48	$36.19	$35.97	$35.78	$35.63	$35.48
-.7%, 13000 BTU	$50.52	$99.23	$52.72	$41.79	$39.90	$39.37	$39.15	$38.94	$38.63	$38.39	$38.20	$38.03	$37.87
-1.0%, 12500 BTU	$45.24	$90.53	$47.94	$36.56	$31.54	$29.89	$28.69	$27.60	$27.25	$27.01	$26.82	$26.59	$26.34
-1.5%, 12500 BTU	$41.55	$80.19	$41.50	$30.47	$28.58	$27.71	$27.30	$26.87	$26.75	$26.63	$26.45	$26.24	$26.02
Ohio													
-4%, 12500 BTU	$39.89	$71.60	$37.71	$25.09	$23.76	$23.29	$22.71	$22.15	$21.60	$21.09	$20.60	$21.11	$20.59
Illinois Basin													
-3%, 11000 BTU (IL)	$27.56	$46.30	$37.74	$28.00	$24.07	$23.50	$23.00	$22.58	$22.18	$21.80	$21.43	$21.08	$20.76
-3%, 11000 BTU (KY)	$29.50	$48.07	$39.00	$29.33	$25.33	$24.73	$24.24	$23.82	$23.42	$23.04	$22.67	$22.31	$21.99
Powder River Basin													
-.33%, 8400 BTU	$8.53	$10.60	$8.50	$8.38	$8.52	$8.14	$7.77	$7.47	$7.24	$7.04	$6.93	$6.83	$6.73
-.35%, 8800 BTU	$10.05	$12.51	$9.85	$9.89	$9.94	$9.63	$9.34	$9.08	$8.85	$8.65	$8.51	$8.38	$8.28
Uinta Basin													
-.5%, 11500 BTU	$30.54	$54.25	$39.84	$20.85	$18.38	$17.51	$16.70	$15.94	$15.22	$14.55	$13.91	$13.30	$12.72
Foreign Coal: Colombia													
-.7%, 12000 BTU	$63.30	$107.87	$54.15	$46.37	$35.75	$31.30	$29.58	$28.97	$28.39	$28.81	$28.84	$28.76	$28.26
-.8%, 11600 BTU	$59.03	$100.60	$50.52	$43.33	$33.47	$29.39	$27.86	$27.33	$26.86	$27.33	$27.38	$27.31	$26.87
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$45.82	$57.93	$27.61	$30.35	$26.74	$22.55	$20.87	$20.44	$20.05	$20.37	$20.39	$20.32	$19.99

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
LOW CASE
August 2008

QUARTERLY SPOT PRICES - NOMINAL DOLLARS PER TON

LOW CASE

Year:	2008				2009				2010			
Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northern Appalachia												
-1.6%, 13000 BTU	$73.12	$106.83	$116.20	$86.55	$62.40	$51.70	$44.15	$39.65	$34.20	$31.05	$28.70	$27.00
-1.8%, 13000 BTU	$72.02	$104.93	$113.20	$84.87	$61.28	$50.75	$43.25	$38.81	$33.52	$30.46	$28.24	$26.57
-2.3%, 13000 BTU	$70.37	$102.07	$108.71	$82.34	$59.59	$49.32	$41.89	$37.56	$32.51	$29.56	$27.56	$25.93
Central Appalachia												
-.7%, 12500 BTU	$73.73	$102.73	$113.55	$82.45	$59.95	$53.66	$46.15	$42.20	$41.00	$40.40	$41.00	$40.65
-.7%, 13000 BTU	$78.58	$109.46	$121.03	$87.86	$63.90	$57.17	$49.20	$44.98	$43.71	$43.06	$43.72	$43.34
-1.0%, 12500 BTU	$70.80	$99.55	$110.98	$80.52	$58.53	$52.17	$44.56	$40.53	$38.95	$37.75	$37.89	$37.25
-1.5%, 12500 BTU	$65.05	$92.03	$95.23	$69.60	$50.88	$45.37	$38.38	$34.87	$32.96	$31.31	$31.07	$31.10
Ohio												
-4%, 12500 BTU	$65.68	$80.68	$77.99	$62.05	$45.84	$38.55	$35.03	$34.54	$29.21	$26.69	$25.00	$23.50
Illinois Basin												
-3%, 11000 BTU (IL)	$31.72	$48.45	$55.70	$49.35	$42.80	$38.80	$37.50	$35.00	$32.00	$30.00	$28.00	$26.50
-3%, 11000 BTU (KY)	$33.63	$50.43	$57.37	$50.83	$44.05	$40.05	$38.76	$36.37	$33.42	$31.48	$29.33	$27.80
Powder River Basin												
-.33%, 8400 BTU	$11.57	$11.53	$10.10	$9.20	$8.90	$8.80	$8.60	$8.40	$8.50	$8.40	$9.00	$8.95
-.35%, 8800 BTU	$13.73	$13.92	$11.58	$10.82	$10.22	$10.22	$9.93	$9.87	$10.00	$9.95	$10.60	$10.60
Uinta Basin												
-.5%, 11500 BTU	$34.37	$50.63	$69.40	$62.60	$55.35	$46.55	$35.70	$28.45	$24.95	$22.45	$21.85	$21.00
Foreign Coal												
-.7%, 12000 BTU	$107.74	$124.32	$123.27	$83.56	$61.32	$56.11	$53.55	$49.84	$51.79	$52.21	$47.53	$39.73
-.8%, 11600 BTU	$100.50	$115.97	$114.93	$77.92	$57.19	$52.34	$49.97	$46.52	$48.37	$48.78	$44.44	$37.15
Petroleum Coke												
-6%/30 HGI, 14000 BTU	$53.01	$66.04	$65.56	$47.08	$34.35	$27.05	$25.13	$26.19	$30.12	$33.30	$33.01	$29.83

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
LOW CASE
August 2008

ANNUAL AVERAGE SPOT PRI

LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$28.42	$28.36	$28.16	$27.97	$27.78	$27.57	$27.37	$27.18	$26.99	$26.79	$26.59
-1.8%, 13000 BTU	$28.22	$28.11	$27.92	$27.73	$27.54	$27.33	$27.13	$26.94	$26.75	$26.56	$26.36
-2.3%, 13000 BTU	$27.91	$27.74	$27.55	$27.36	$27.17	$26.97	$26.77	$26.59	$26.40	$26.21	$26.01
Central Appalachia											
-.7%, 12500 BTU	$44.70	$45.35	$45.99	$46.65	$47.31	$47.95	$48.83	$49.75	$50.67	$51.60	$52.55
-.7%, 13000 BTU	$47.72	$48.41	$49.10	$49.81	$50.52	$51.21	$52.15	$53.13	$54.13	$55.13	$56.14
-1.0%, 12500 BTU	$33.07	$33.40	$33.76	$34.09	$34.43	$34.74	$35.19	$35.67	$36.14	$36.63	$37.16
-1.5%, 12500 BTU	$32.70	$33.04	$33.40	$33.74	$34.08	$34.40	$34.86	$35.35	$35.82	$36.31	$36.84
Ohio											
-4%, 12500 BTU	$25.43	$25.28	$25.12	$24.97	$24.80	$24.63	$24.46	$24.30	$24.14	$23.98	$23.81
Illinois Basin											
-3%, 11000 BTU (IL)	$25.88	$25.98	$26.06	$26.15	$26.21	$26.26	$26.31	$26.38	$26.42	$26.46	$26.49
-3%, 11000 BTU (KY)	$27.44	$27.56	$27.68	$27.79	$27.88	$27.95	$28.03	$28.12	$28.20	$28.25	$28.31
Powder River Basin											
-.33%, 8400 BTU	$8.42	$8.49	$8.53	$8.54	$8.54	$8.54	$8.54	$8.54	$8.55	$8.55	$8.56
-.35%, 8800 BTU	$10.41	$10.50	$10.56	$10.60	$10.63	$10.66	$10.69	$10.73	$10.77	$10.82	$10.87
Uinta Basin											
-.5%, 11500 BTU	$15.39	$15.02	$14.67	$14.33	$14.00	$13.69	$13.39	$13.10	$12.82	$12.55	$12.30
Foreign Coal											
-.7%, 12000 BTU	$35.18	$35.24	$35.32	$35.32	$35.32	$34.91	$34.67	$34.83	$35.01	$35.23	$35.45
-.8%, 11600 BTU	$33.51	$33.59	$33.68	$33.69	$33.68	$33.32	$33.08	$33.24	$33.41	$33.62	$33.83
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$24.92	$24.97	$25.01	$25.02	$25.04	$24.79	$24.64	$24.80	$24.97	$25.18	$25.38

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
LOW CASE
August 2008

ANNUAL AVERAGE SPOT PRI
LOW CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$22.45	$21.98	$21.42	$20.88	$20.36	$19.85	$19.35	$18.86	$18.38	$17.92	$17.47
-1.8%, 13000 BTU	$22.29	$21.79	$21.24	$20.70	$20.18	$19.67	$19.18	$18.69	$18.22	$17.76	$17.32
-2.3%, 13000 BTU	$22.05	$21.50	$20.96	$20.43	$19.92	$19.41	$18.92	$18.45	$17.98	$17.53	$17.09
Central Appalachia											
-.7%, 12500 BTU	$35.32	$35.15	$34.99	$34.83	$34.67	$34.51	$34.51	$34.51	$34.51	$34.51	$34.51
-.7%, 13000 BTU	$37.70	$37.62	$37.35	$37.19	$37.02	$36.86	$36.86	$36.87	$36.87	$36.87	$36.88
-1.0%, 12500 BTU	$26.13	$25.89	$25.68	$25.45	$25.23	$25.01	$24.87	$24.75	$24.62	$24.50	$24.41
-1.5%, 12500 BTU	$25.83	$25.61	$25.41	$25.19	$24.98	$24.76	$24.64	$24.53	$24.40	$24.29	$24.20
Ohio											
-4%, 12500 BTU	$20.09	$19.60	$19.11	$18.64	$18.18	$17.73	$17.29	$16.86	$16.44	$16.04	$15.64
Illinois Basin											
-3%, 11000 BTU (IL)	$20.45	$20.14	$19.83	$19.52	$19.21	$18.90	$18.60	$18.30	$18.00	$17.70	$17.40
-3%, 11000 BTU (KY)	$21.68	$21.37	$21.05	$20.75	$20.43	$20.12	$19.81	$19.51	$19.21	$18.90	$18.60
Powder River Basin											
-.33%, 8400 BTU	$6.65	$6.58	$6.49	$6.38	$6.26	$6.15	$6.03	$5.93	$5.82	$5.72	$5.62
-.35%, 8800 BTU	$8.22	$8.14	$8.04	$7.91	$7.79	$7.68	$7.56	$7.45	$7.34	$7.23	$7.14
Uinta Basin											
-.5%, 11500 BTU	$12.16	$11.64	$11.16	$10.70	$10.26	$9.85	$9.46	$9.09	$8.73	$8.40	$8.08
Foreign Coal: Colombia											
-.7%, 12000 BTU	$27.80	$27.32	$26.87	$26.37	$25.88	$25.13	$24.50	$24.16	$23.85	$23.56	$23.28
-.8%, 11600 BTU	$26.48	$26.04	$25.62	$25.15	$24.69	$23.98	$23.38	$23.06	$22.76	$22.49	$22.22
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$19.69	$19.36	$19.03	$18.68	$18.35	$17.84	$17.42	$17.20	$17.01	$16.84	$16.67

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.

BUSINESS-AS-USUAL CASE

August 2008

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ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BUSINESS-AS-USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$46.61	$109.29	$100.38	$56.06	$41.01	$42.71	$44.22	$44.53	$45.07	$45.62	$46.23	$46.84	$47.55
-1.8%, 13000 BTU	$45.85	$107.07	$98.45	$55.05	$40.30	$42.10	$43.69	$44.11	$44.67	$45.24	$45.85	$46.48	$47.21
-2.3%, 13000 BTU	$44.71	$103.75	$95.54	$53.54	$39.25	$41.18	$42.90	$43.49	$44.07	$44.67	$45.28	$45.94	$46.70
Central Appalachia													
-.7%, 12500 BTU	$46.46	$108.30	$105.04	$64.73	$55.26	$59.43	$61.64	$64.04	$65.55	$64.91	$65.34	$66.08	$67.80
-.7%, 13000 BTU	$49.50	$115.41	$111.96	$69.02	$59.03	$63.45	$61.64	$68.36	$69.97	$69.28	$69.75	$70.53	$72.38
-1.0%, 12500 BTU	$44.33	$105.29	$101.83	$60.38	$47.70	$48.47	$50.82	$48.96	$49.32	$48.72	$48.94	$49.31	$50.32
-1.5%, 12500 BTU	$40.72	$93.27	$88.15	$50.33	$42.29	$44.65	$45.89	$47.17	$48.45	$48.05	$48.30	$48.67	$49.73
Ohio													
-4%, 12500 BTU	$39.19	$81.14	$78.23	$48.35	$35.60	$37.37	$38.95	$39.51	$40.06	$40.62	$41.19	$41.81	$42.52
Illinois Basin													
-3%, 11000 BTU (IL)	$27.01	$50.75	$54.48	$38.12	$34.09	$34.16	$34.32	$34.61	$34.92	$35.26	$35.59	$35.93	$36.28
-3%, 11000 BTU (KY)	$28.91	$52.65	$56.29	$39.93	$35.87	$35.94	$36.15	$36.49	$36.85	$37.25	$37.62	$38.01	$38.41
Powder River Basin													
-.33%, 8400 BTU	$8.36	$11.77	$11.99	$11.08	$10.99	$11.00	$10.96	$11.00	$11.09	$11.17	$11.37	$11.54	$11.74
-.35%, 8800 BTU	$9.85	$13.78	$13.40	$12.50	$12.84	$12.98	$13.11	$13.26	$13.43	$13.61	$13.85	$14.07	$14.36
Uinta Basin													
-.5%, 11500 BTU	$29.93	$59.78	$54.61	$27.08	$25.68	$24.64	$25.00	$25.40	$25.79	$26.20	$26.61	$27.05	$27.57
Foreign Coal													
-.7%, 12000 BTU	$62.03	$125.45	$115.01	$76.58	$54.06	$50.75	$52.40	$51.40	$51.40	$51.96	$52.64	$53.33	$53.99
-.8%, 11600 BTU	$57.85	$117.00	$107.30	$71.56	$50.62	$47.66	$49.34	$48.49	$48.63	$49.30	$49.97	$50.64	$51.33
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$44.90	$66.62	$58.65	$50.02	$40.44	$36.56	$36.96	$36.26	$36.30	$36.75	$37.21	$37.68	$38.18

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
BUSINESS-AS-USUAL CASE
August 2008

ANNUAL AVERAGE SPOT PRICES - REAL 2008 DOLLARS PER TON

BUSINESS-AS-USUAL CASE

Year:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Northern Appalachia													
-1.6%, 13000 BTU	$47.57	$109.29	$98.34	$53.89	$38.64	$39.41	$40.01	$39.51	$39.22	$38.97	$38.75	$38.52	$38.33
-1.8%, 13000 BTU	$46.79	$107.07	$96.44	$52.92	$37.98	$38.84	$39.53	$39.14	$38.88	$38.64	$38.43	$38.22	$38.06
-2.3%, 13000 BTU	$45.62	$103.75	$93.59	$51.47	$36.98	$38.00	$38.81	$38.58	$38.36	$38.15	$37.95	$37.77	$37.64
Central Appalachia													
-.7%, 12500 BTU	$47.41	$108.30	$102.90	$62.23	$52.07	$54.84	$55.76	$56.82	$57.05	$55.44	$54.77	$54.33	$54.66
-.7%, 13000 BTU	$50.52	$115.41	$109.68	$66.35	$55.62	$58.55	$55.76	$60.65	$60.90	$59.17	$58.46	$57.99	$58.35
-1.0%, 12500 BTU	$46.24	$105.29	$99.75	$58.05	$44.94	$44.73	$45.98	$43.44	$42.93	$41.61	$41.03	$40.54	$40.56
-1.5%, 12500 BTU	$41.56	$93.27	$86.35	$48.39	$39.85	$41.20	$41.51	$41.85	$42.17	$41.04	$40.48	$40.02	$40.09
Ohio													
-4%, 12500 BTU	$39.99	$81.14	$76.63	$46.49	$33.55	$34.49	$35.24	$35.05	$34.86	$34.69	$34.53	$34.38	$34.28
Illinois Basin													
-3%, 11000 BTU (IL)	$27.56	$50.75	$53.37	$36.65	$32.13	$31.52	$31.05	$30.71	$30.40	$30.12	$29.83	$29.54	$29.25
-3%, 11000 BTU (KY)	$29.50	$52.65	$55.14	$38.38	$33.80	$33.17	$32.70	$32.38	$32.07	$31.81	$31.53	$31.25	$30.96
Powder River Basin													
-.33%, 8400 BTU	$8.53	$11.77	$11.75	$10.66	$10.36	$10.15	$9.92	$9.76	$9.65	$9.54	$9.53	$9.49	$9.46
-.35%, 8800 BTU	$10.05	$13.78	$13.12	$12.01	$12.10	$11.98	$11.86	$11.76	$11.69	$11.63	$11.61	$11.57	$11.58
Uinta Basin													
-.5%, 11500 BTU	$30.54	$59.78	$53.50	$26.03	$24.20	$22.74	$22.62	$22.54	$22.45	$22.38	$22.30	$22.24	$22.22
Foreign Coal: Colombia													
-.7%, 12000 BTU	$63.30	$125.45	$112.67	$73.63	$50.94	$46.83	$47.40	$45.61	$44.74	$44.38	$44.13	$43.85	$43.52
-.8%, 11600 BTU	$59.03	$117.00	$105.11	$68.80	$47.69	$43.97	$44.63	$43.02	$42.32	$42.11	$41.88	$41.64	$41.38
Petroleum Coke													
-6%/30 HGI, 14000 BTU	$45.82	$66.62	$57.46	$48.09	$38.10	$33.74	$33.44	$32.17	$31.59	$31.39	$31.19	$30.98	$30.78

QCF (QUARTERLY COAL FORECAST) - 200804

JD Energy, Inc.
BUSINESS-AS-USUAL CASE
August 2008

ANNUAL AVERAGE SPOT F

BUSINESS-AS-USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$48.29	$47.90	$48.63	$49.41	$50.14	$50.85	$51.60	$52.40	$53.17	$53.93	$54.70
-1.8%, 13000 BTU	$47.98	$47.49	$48.21	$48.98	$49.70	$50.41	$51.15	$51.94	$52.71	$53.46	$54.23
-2.3%, 13000 BTU	$47.51	$46.86	$47.58	$48.33	$49.05	$49.74	$50.47	$51.26	$52.01	$52.75	$53.51
Central Appalachia											
-.7%, 12500 BTU	$69.46	$70.43	$71.38	$73.35	$75.37	$78.29	$81.40	$83.78	$86.17	$88.54	$90.90
-.7%, 13000 BTU	$74.15	$75.18	$76.21	$78.31	$80.48	$83.61	$86.94	$89.49	$92.05	$94.59	$97.13
-1.0%, 12500 BTU	$51.38	$51.87	$52.39	$53.60	$54.86	$56.73	$58.68	$60.09	$61.47	$62.86	$64.29
-1.5%, 12500 BTU	$50.81	$51.31	$51.84	$53.04	$54.30	$56.18	$58.12	$59.53	$60.92	$62.31	$63.74
Ohio											
-4%, 12500 BTU	$43.28	$42.71	$43.38	$44.09	$44.77	$45.42	$46.11	$46.85	$47.57	$48.27	$48.98
Illinois Basin											
-3%, 11000 BTU (IL)	$36.68	$37.04	$37.42	$37.81	$38.19	$38.60	$39.00	$39.40	$39.78	$40.17	$40.58
-3%, 11000 BTU (KY)	$38.85	$39.27	$39.70	$40.14	$40.58	$41.04	$41.50	$41.96	$42.40	$42.84	$43.32
Powder River Basin											
-.33%, 8400 BTU	$11.94	$12.11	$12.24	$12.41	$12.54	$12.67	$12.81	$12.96	$13.10	$13.23	$13.38
-.35%, 8800 BTU	$14.69	$14.97	$15.19	$15.45	$15.68	$15.91	$16.15	$16.41	$16.66	$16.91	$17.17
Uinta Basin											
-.5%, 11500 BTU	$28.11	$28.62	$29.12	$29.65	$30.16	$30.66	$31.18	$31.73	$32.27	$32.80	$33.34
Foreign Coal											
-.7%, 12000 BTU	$54.66	$54.73	$54.82	$55.54	$56.27	$57.02	$57.81	$58.66	$59.55	$60.46	$61.33
-.8%, 11600 BTU	$52.06	$52.17	$52.27	$52.97	$53.68	$54.41	$55.17	$55.98	$56.83	$57.70	$58.52
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$38.71	$38.78	$38.81	$39.34	$39.90	$40.48	$41.09	$41.77	$42.48	$43.22	$43.91

QCF (QUARTERLY COAL FORECAST) - 200804
JD Energy, Inc.
BUSINESS AS USUAL CASE
August 2008

ANNUAL AVERAGE SPOT F
BUSINESS AS USUAL CASE

Year:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Northern Appalachia											
-1.6%, 13000 BTU	$38.15	$37.13	$37.00	$36.89	$36.75	$36.60	$36.47	$36.35	$36.22	$36.07	$35.93
-1.8%, 13000 BTU	$37.91	$36.81	$36.68	$36.57	$36.43	$36.28	$36.15	$36.04	$35.90	$35.76	$35.62
-2.3%, 13000 BTU	$37.53	$36.32	$36.19	$36.08	$35.95	$35.80	$35.68	$35.56	$35.43	$35.29	$35.15
Central Appalachia											
-.7%, 12500 BTU	$54.88	$54.59	$54.30	$54.76	$55.24	$56.35	$57.54	$58.13	$58.69	$59.22	$59.71
-.7%, 13000 BTU	$58.58	$58.28	$57.97	$58.47	$58.98	$60.18	$61.45	$62.09	$62.70	$63.27	$63.80
-1.0%, 12500 BTU	$40.59	$40.21	$39.86	$40.01	$40.20	$40.83	$41.47	$41.69	$41.87	$42.05	$42.23
-1.5%, 12500 BTU	$40.14	$39.77	$39.43	$39.60	$39.80	$40.43	$41.08	$41.31	$41.50	$41.68	$41.87
Ohio											
-4%, 12500 BTU	$34.19	$33.11	$33.00	$32.92	$32.81	$32.70	$32.59	$32.51	$32.40	$32.28	$32.18
Illinois Basin											
-3%, 11000 BTU (IL)	$28.98	$28.71	$28.46	$28.23	$27.99	$27.78	$27.57	$27.34	$27.10	$26.87	$26.65
-3%, 11000 BTU (KY)	$30.70	$30.44	$30.20	$29.97	$29.74	$29.54	$29.33	$29.11	$28.88	$28.66	$28.45
Powder River Basin											
-.33%, 8400 BTU	$9.43	$9.39	$9.31	$9.26	$9.19	$9.12	$9.05	$8.99	$8.92	$8.85	$8.79
-.35%, 8800 BTU	$11.61	$11.60	$11.55	$11.53	$11.49	$11.45	$11.41	$11.38	$11.35	$11.31	$11.28
Uinta Basin											
-.5%, 11500 BTU	$22.21	$22.18	$22.15	$22.14	$22.10	$22.07	$22.04	$22.01	$21.98	$21.94	$21.90
Foreign Coal: Colombia											
-.7%, 12000 BTU	$43.18	$42.42	$41.71	$41.46	$41.24	$41.04	$40.86	$40.70	$40.56	$40.44	$40.28
-.8%, 11600 BTU	$41.13	$40.44	$39.76	$39.55	$39.35	$39.16	$38.99	$38.84	$38.71	$38.59	$38.44
Petroleum Coke											
-6%/30 HGI, 14000 BTU	$30.58	$30.06	$29.53	$29.37	$29.24	$29.13	$29.04	$28.98	$28.93	$28.91	$28.84

THE STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Merrimack Station Scrubber Project
Request for Information

Docket No. DE 08-103

Report

In its Secretarial Letter dated August 22, 2008 in this docket, the Commission notified Public Service Company of New Hampshire (PSNH) that it was conducting an inquiry into the status of PSNH's efforts to install a wet flue gas desulphurization system (scrubber technology) at Merrimack Station in Bow. Installation of the scrubber (the "Clean Air Project") is mandated by RSA 125-O:11 through 18 (the "Scrubber Law") to achieve reductions in mercury emissions. The Commission directed PSNH to file, by September 12, 2008:

I. a comprehensive status report on its installation plans;

II. a detailed cost estimate for the project;

III. an analysis of the anticipated effect of the project on energy service rates; and

IV. an analysis of the effect on energy service rates if Merrimack Station were not in the mix of fossil and hydro facilities operated by PSNH.

This report provides the information concerning PSNH's scrubber installation project (the Clean Air Project) requested by the Commission's secretarial letter.

I. Scrubber Status

PSNH is moving rapidly forward with the Clean Air Project to comply with the Scrubber Law's mandate to achieve significant reductions in mercury emissions at the coal-burning electric power plants in the state as soon as possible. RSA 125-O:11, I. Unless further delayed, PSNH will meet the statutory installation deadline of July 1, 2013, and is striving to have the scrubber operational sooner than that deadline. The scope of the Clean Air Project will encompass planning and design; schedule and cost development; oversight of multiple competitive bidding processes for engineering; equipment and system procurement, selection of contractors, contract negotiations and execution; sequential construction management of the various project components and interfaces, followed by the integration of those components into a functioning system; and operational start-up activities. All work on the Clean Air Project will be performed with safety as a high priority. To date, PSNH has spent approximately $10 million on the Clean Air Project.

A. Activities Performed during 2006

1. Merrimack Station began investigating operational changes at the facility that would provide the necessary flexibility in the design and engineering of a scrubber system. The catalyst replacement program on the previously installed selective catalytic reduction systems was reviewed and updated to accommodate operating requirements of a new scrubber and potentially improve the overall performance of the equipment.

2. Merrimack Station revised, tested and modified its ash handling operations and capabilities to provide necessary options for ash management in order to maximize unit operations when a new scrubber is installed.

3. Initial engineering was completed by Sargent and Lundy ("S&L") based upon information provided in 2005. S&L also evaluated a number of equipment options integral to the scrubber project and completed a layout of the project. Budgetary quotes and lead times were solicited from major scrubber vendors, also during 2005.

4. General specifications for the scrubber island, material handling system and the chimney were provided to PSNH by S&L to further develop project requirements. To complement this preliminary engineering work, site visits to the other scrubber installations were completed by PSNH/Merrimack Station personnel.

5. Preliminary work in support of the temporary air permit application was completed including emissions netting calculations and suggested modeling protocol.

6. Water quality testing was completed to define and identify appropriate sources for make-up water to the scrubber system.

7. Electrical work was reviewed with PSNH transmission and distribution divisions to outline the power requirements for the new scrubber system. A two phase approach was defined. Plans were made to relocate and upgrade an existing, old construction yard in order for the land to be used for construction power for the scrubber system. A new substation will be installed to power the scrubber operations.

8. Also in preparation for the scrubber installation, an unused oil tank was removed from the north side of the plant. This space will eventually house portions of the material handling system required by the scrubber project.

9. A study of the Merrimack property's south yard was performed to ensure an adequate layout area for the necessary equipment and building surrounding the scrubber. A number of contractor facilities in the south end of the plant, as well as the existing training facility, were identified for relocation.

10. A portion of the southern-most yard was cleared to make room for a new warehouse building. Although a separate effort from construction of the scrubber project itself, it

was necessary to complete this work prior to the extensive construction and labor effort that will be underway during the construction of the scrubber islands. Preliminary engineering, design, surveying and permitting for this new warehouse were completed.

11. A number of appropriate purchasing and procurement efforts were completed including contract options and strategy analysis and vendor lists for scrubber manufacturers and architect/engineers.

12. Engineering efforts included review of the latest equipment options, equipment integration capabilities, and mercury capture capabilities.

13. Also initial investigation into gypsum disposal and sale opportunities was pursued with various wallboard manufacturers.

B. Activities Performed during 2007

1. Merrimack Station continued operational changes at the facility that would provide the necessary flexibility to accommodate the design and engineering of a scrubber system. The station worked to modify boiler combustion temperatures. Tube shields were removed from the boiler reheater to increase heat transfer and improve steam temperatures.

2. The station's south yard was cleared for the new warehouse on schedule. This new warehouse will initially house displaced inventory from existing warehouse buildings. The building permit application was submitted on May 17, 2007. Preliminary design of the building was completed.

3. PSNH went out to bid for the Program Manager for the Clean Air Project on May 15, 2007. URS Washington Division ("URS") was hired in October 2007 following lengthy contract negotiations.

4. PSNH submitted a Temporary Air Permit application for the Clean Air Project with NHDES on June 6, 2007. An emissions netting calculation and determination of a stack height consistent with good engineering practice ("GEP") were required information to support the Temporary Air Permit application submittal. Necessary air dispersion modeling services were contracted for and have begun.

5. The first legislative update, as required annually by RSA 125-O:13, IX was completed on June 26, 2007. PSNH is required to report on the progress, status, and cost of complying with the provisions of the scrubber law to the legislative oversight committee on electric utility restructuring, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee;. A brief summary of that first update follows:

- Engineering
    i. Specifications developed for key components
    ii. Possible site plan layouts developed
    iii. Equipment options identified
    iv. Vendor lists and contacts established
    v. Industry impact of high number of scrubber installations analyzed
- Commercial and Purchasing
    i. Contract strategy determined and approved
    ii. Program Manager specification written
    iii. Program Manager out to bid
- Permits and Approvals
    i. Temporary Air Permit Application submitted to NHDES-ARD June 7, 2007
    ii. Town of Bow presentations and submittals underway
    iii. Company financing approvals initiated
- Site work
    i. Existing oil tank removal completed
    ii. Site surveys completed
    iii. South Yard studies completed

C. <u>Activities Performed during 2008 to date</u>

1. Construction of the major components of the Clean Air Project has been broken down into the engineering, procurement, and construction of four major work islands which include the scrubber, chimney, waste water treatment facility, and material handling system. Construction must occur on a sequential basis. Of these islands, the chimney and scrubber require completion first for safety reasons given the physical orientation of the equipment and constraints of the site. Following foundation work, the chimney "shell" construction must precede all work because of the necessity of preserving a "drop zone" or area around the chimney for evident safety reasons. As a result of these sequential construction requirements, both the scrubber island and chimney specifications were prioritized and sent out to bid first, vendor bid proposals were received, bid proposals were reviewed to identify the lowest evaluated bidder and negotiations with lowest evaluated bidders were undertaken. The negotiations are in final stages on both contracts and the contracts were expected to be executed this week; however, as a result of the initiation of this inquiry, such contracts must await the Commission's action in this inquiry. The material handling system and waste water treatment system followed with specifications sent out to bid, bid proposals received and evaluated, and negotiations well under way. Contracts will be finalized in short order and will be ready to execute in the near-term.

2. A second annual legislative update was completed on June 18, 2008. The status of the scrubber installation and mercury reductions was reported on to the legislative oversight committee on electric utility restructuring, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee. A summary of that update follows:

- Engineering
    i. Project's components
    ii. Specifications developed for 4 key components
- Commercial and Purchasing
    i. Program Manager hired Sept 2007
    ii. Scrubber Island and Chimney proposals are in negotiations
    iii. Vendor Proposals requested and received for Wastewater Treatment Facility and Material Handling System
- Review, Permits and Approvals
    i. NHDES – May 12 presentation
    ii. Temporary Permit expected October 2008
    iii. Town of Bow –Local permitting
    iv. Regional Planning Commission
- Site work
    i. Existing oil tank removed
    ii. Site surveys and studies completed
    iii. Warehouse construction underway
    iv. On-site engineering facilities completed
- Schedule and Costs
    i. Tie-ins: MK#1 Fall 2012, MK#2 Spring 2013
    ii. Project costs will be updated with review of major equipment bids

3. It was reiterated at this update that PSNH was focused on expediting the schedule; and with two major equipment islands in negotiations, it would soon be known to what extent the critical path of this project could be potentially shortened. These negotiations would also provide updated costs associated with a new timeline.

4. As referenced earlier, negotiations with the scrubber island and chimney are now in their final phase. Recently completed boiler implosion, burner management and electrical supply studies are being reviewed. Multiple meetings have been attended in the Town of Bow focusing on local permitting requirements and also addressing any Regional Impact considerations. With that, public outreach and education meetings have been conducted and/or scheduled with a variety of organizations, such as the Southern New Hampshire Planning Commission, the Town of Pembroke, Town of Hooksett, etc.

5. Finally, air modeling is being completed with current engineering and equipment design information and proposed site orientation. Drafting of the Temporary Air Permit continues by the New Hampshire Department of Environmental Services (NHDES) Air Division.

D. Schedule Status

1. As the project has moved forward steadily, PSNH has obtained more detailed information from major equipment and system suppliers, and has adjusted the schedule accordingly. The current optimized schedule shows that completion of the Clean Air Project in 2012 is

possible if there are no additional delays. PSNH's efforts are now focused on an early completion, as required by RSA 125-O:11, I. The early completion date is attributable to PSNH's diligence in complying with the Scrubber Law's mandates as rapidly as reasonably possible. Early completion will be beneficial to customers because AFUDC will be reduced, customers will benefit from early reductions credits provided by the Scrubber Law's Economic Performance Incentives at RSA 125-O:16, and, most importantly, mercury and sulfur oxide emissions will be reduced. In addition, by finalizing fixed price contracts and locking in prices, additional escalation of commodities can be avoided to some extent.

2. An early completion date is predicated on successful completion of a number of critical activities on a timely basis. These activities include obtaining permits to proceed with construction in the Fall of 2008 from the Town of Bow, and the receipt of a Temporary Air Permit from the New Hampshire Department of Environmental Services in the Fall of 2008. Moreover, procurement of engineering services and equipment must proceed on an aggressive schedule. Even a short delay at this time could trigger a six to eight month delay in completion of the project because foundation construction work must commence in the Fall of 2009. If foundation construction work is not completed in the Fall of 2009, the work will have to be delayed until the Spring of 2010 because it cannot be performed during winter months. This illustrates the valid concern that even a brief delay has the potential for creating a domino effect on project schedule with far more than a day-for-day delay.

3. The schedule is aggressive and has only a small tolerance for unpredictable delays due to inclement weather, equipment delivery problems, resolving engineering or design problems, or start-up and testing problems. Consequently, any delays caused by regulatory actions or other unanticipated events could jeopardize PSNH's ability to adhere to the schedule. Any such delay would increase the cost of the project.

B. Engineering Status

1. URS has overall responsibility to develop the cost and schedule, subject to PSNH's review and approval.

2. The initial estimated cost of the project was based on a Sargent & Lundy estimate performed in 2005. There have been significant increases in the cost of raw materials, steel, labor, and energy, since this estimate was made, as noted by the *Wall Street Journal* in a May 27, 2008 article entitled "Costs to Build Power Plants Pressure Rates" (Atch 1) and echoed by the FERC's Office of Enforcement's report to the FERC Commissioners on Increasing Costs in Electric Markets, presented on June 19, 2008 (Atch 2). URS has more current information and experience with this type of work, and they developed a revised estimated project cost based on their experience with such projects and on bids received from the four major system vendors (Scrubber, Stack, Material Handling, and Waste Water Treatment Islands).

3. Approximately 60% to 70% percent of the revised project cost is now based on firm contracts or firm bids PSNH has received. Only small system and interconnection field systems (electrical, ductwork, piping, yard work, etc.) have yet to be finalized by bids. If bids in hand are not acted on in a timely manner, such delay in execution of contracts can and will result in a delay in project completion and higher costs.

4. URS has 30 engineers currently working on the project in the following areas:
   a. Electrical engineering
   b. Civil engineering
   c. Structural engineering
   d. Controls
   e. Fire Protection
   f. Estimators
   g. Schedulers
   h. Draftsmen.

5. URS's efforts are approaching peak workload. This is a critical time in their efforts and any upset will create risk of delay and added cost.

6. Current work activities include site preparation, planning, and design. Once the shovel is in the ground, construction activities will go on for approximately four years. Because there will be more than 300 people working on the project at peak periods, the work must be carefully planned and performed. Construction will be performed by union craft labor, and an organized labor National Maintenance Agreement has been executed to ensure availability of workers and eliminate the potential for labor disputes as well as to prioritize safety on the job.

7. Parts lay-down and storage areas must be developed, site trench layout for electrical and piping systems need to be designed, and contractor parking and access paths need to be built.

<u>F. Current Procurement and Construction Activities</u>

1. PSNH has been actively engaged in negotiating contracts for various aspects of the project. PSNH has completed bid evaluations for the waste water treatment system and material handling system and those contracts are under negotiation. Bidding is currently in progress for items like the construction power electrical switching panel, booster fans and motors, and a new electrical substation.

2. Negotiations are about to be finalized on the scrubber and chimney. However, as noted in the Motion to Accelerate Schedule filed with the Commission on August 25th, PSNH and its corporate parent, Northeast Utilities, cannot continue to commit additional dollars to the scrubber project until the Commission determines its actions in this inquiry. PSNH will initiate discussions with various bidders and contractors to seek ways to continue to allow limited critical path work to proceed, if possible. However, as stated above,

escalating costs for global commodities such as steel and cabling make it likely that any delay in the receipt of Commission action will increase the cost of the project.

3. PSNH has also been designing and procuring equipment for the two substations that will be constructed to support the project. One substation is replacing an existing substation and will eventually be used for construction and a second larger substation will be needed to provide power to the scrubber once it is operational.

4. Site drawings have been developed to show new gates, new access roads, the construction guard house, office trailer locations, new parts lay-down and storage locations, security, and first aid locations. Work is progressing on soil borings to support foundation design, site surveys are being conducted for general equipment locations, and extensive underground surveying is being performed to locate all buried items.

5. Other current activities include developing specifications for booster fans and duct work, designing yard fire protection systems, conducting noise studies, and performing electrical usage studies. Myriad other tasks are also currently being performed in order to successfully complete the project.

G. <u>Permitting Activities</u>

1. The permitting activities began with submittal of the Temporary Air Permit application submitted to NHDES on June 7, 2007. NHDES has indicated that it will facilitate the permitting process however possible and has offered to provide a staff liaison to assist.

2. Other permitting activities have occurred over the last six months and are ongoing. Most notably, PSNH must receive approval from the Town of Bow. PSNH currently expects to receive the necessary approvals within the next few months.

II. PROJECT COST ESTIMATE

A. PSNH, in consultation with URS, has developed a revised project cost estimate of $457 million. This cost equates to approximately $830 per kW for all of the "affected sources" subject to the emissions limitations of the Scrubber Law (RSA 125-O:12, I) or $1,054 per kW installed for Merrimack Station alone. This estimate includes the cost of the project, project management costs, AFUDC, indirect costs, and contingency. Confidential Attachment 3 hereto provides a detailed breakdown of project costs.

B. The current project cost estimate is in-line with recently published information on other multiple unit scrubber installations occurring elsewhere in the country. SNL Financial reported in their July 8, 2008 edition that the Wisconsin PSC had given verbal authorization for Wisconsin Energy Corp to proceed with its plans to install Scrubber and Selective Catalytic Reduction technologies to its Oak Creek units 5-8, a total of 525 MW's of existing Coal fired generating capacity at a cost of $774 Million. While this cost includes the addition of two emissions reduction technologies, the installed cost equates to $1,474 per kW at Oak Creek.

III. Effect of Clean Air Project on Energy Service Rates

A. PSNH has assured the cost of energy produced by Merrimack Station will remain lower cost for customers than reasonable potential alternatives, even when the costs of the Clean Air Project are included. An analysis consisting of a detailed net present value of revenue requirements including capital and operating costs over the expected 15 year depreciation life of the scrubber demonstrates the continued economics of installing the scrubber provides this assurance. The spreadsheets which contain this analysis are included as Attachment 4 to this filing.

B. The primary assumptions used as inputs to the revenue requirements analysis include:

Capital cost: $457M
Capital structure: 47.23% Equity, 52.77% Debt
Assumed Return on Equity: 9.81% (PSNH's current allowed ROE on generation)
In-Service Date: July 1, 2012
Coal cost: $4.82 per Million BTU escalated at 2.5% per year for the period of the analysis
RGGI or equivalent CO2 allowance cost: $7 per ton escalated at 2.5% per year for the period of the analysis

Utilizing these inputs produced the following summary results:
First year bus bar cost: $94.55/MWh
Levelized (15 year) bus bar cost: $99.28/MWh

C. Using the 2012 - 2027 average bus bar cost, the effect that the Clean Air Project will have on energy service rates is estimated to be approximately one-third of a cent per kWh (1/3¢/kWh). In the first year of operation, the year with the highest cost impact due to the highest value of undepreciated plant, absent any rate-smoothing initiatives, the impact on energy service rates is estimated to be approximately one-half cent per kWh (1/2¢/kWh).

D. Sensitivity analyses were conducted to test the impact of changes to each of the key assumptions (capital cost, coal cost and equivalent CO2 allowance cost) on the overall bus bar cost of Merrimack Station. These sensitivity analyses indicated the economics of the project are most sensitive to variations in the future price of coal, and far less sensitive to variations in the capital cost or equivalent CO2 allowance cost.

IV. Effect on Energy Service Rates if Merrimack Station is Retired

A. The Commission's Secretarial Letter requires "an analysis of the effect on energy service rates if Merrimack Station were not in the mix of fossil and hydro facilities operated by PSNH." Three alternatives were chosen for this analysis. These comparison cases included analyses over the time frame of 2012 through 2027 of the following options:

1. Purchase of energy and capacity to replace the equivalent of Merrimack Station through a "Cost of Service" contract with new base load coal fired generating station;

2. Purchase of energy and capacity to replace the equivalent of Merrimack Station through a "Cost of Service" contract with a new combined cycle natural gas fired generating station; and

3. Purchase of energy and capacity to replace the equivalent of Merrimack Station through market purchases.

B. The 2012 through 2027 analysis period was chosen to coincide with the anticipated 15 year depreciable life of the scrubber, as defined in the base case. Cost of service style contracts, though not routinely in place in ISO-New England at this time, provided a presumed floor for total operating costs for a new coal or natural gas fired unit, employing a presumed "regulated return" and debt/equity ratio consistent with the PSNH values used in the base case, of operating with the scrubber.

C. PSNH undertook a data review of energy trade press and publications to determine current estimates of newly proposed coal and natural gas combined cycle generating stations.

1. For recently proposed coal plants, PSNH found references to the Virginia City Hybrid facility (Attachment 5). This is a 585 MW fluidized bed facility with a currently reported capital cost of $1.8 billion. A net present value of revenue requirements model was created that employed this capital cost, the PSNH capital structure and anticipated ROE, and for the sake of consistency, coal price and equivalent CO_2 allowance cost assumptions consistent with those used in the scrubber analysis. FERC has estimated significantly higher costs for construction of new coal generation, as set forth in Attachment 2.

2. For recently proposed combined cycle natural gas plants, PSNH found references to the Middletown Kleen plant, a 620 MW plant with a currently reported financing of $985 Million (Attachment 6). This cost is consistent with the FERC estimated cost of new generation contained in Attachment 2.

D. For future market conditions, PSNH examined the forward market for natural gas delivered to New England and applied a "heat rate" factor to translate the raw delivered fuel cost to electrical energy. To the energy cost derived from these calculations, an adder was applied for ISO-NE capacity value, which would be required to replace the lost capacity value existing with the operation of Merrimack Station.

E. In the market purchase and combined cycle natural gas scenarios, a year 2012 price of $11 per MMbtu was used as the first year price of natural gas. This value was escalated at a rate 2.5% per year for future years of the analysis.

F. The results of these analyses indicated that the new coal and new combined cycle natural gas plants would have bus bar costs of about $135 per MWhr. For the market purchase alternative the sum of the energy and capacity costs resulted in a total cost per MWhr value of $107.10. To this amount, PSNH calculated and added a recovery of the estimated $63 Million of stranded assets (undepreciated plant and inventories) that would exist at Merrimack Station over a period of five years (as required by RSA 369-B:3-a). The overall cost of a market purchase plus retirement scenario produced a levelized bus bar cost of $107.83/MWhr, which is nearly 15% higher than the cost calculated to operate Merrimack Station in the first year after completion of the Clean Air Project.

G. From these results, PSNH has computed that the average net effect on energy service rates if Merrimack Station is retired and replaced by market purchases would be 0.73 cents/kWh of additional costs to customers over the period of 2012 through 2027.

H. Comparison and sensitivity analyses were conducted using the scrubber and market purchase plus retirement scenarios. Under the base case assumptions the scrubber scenario produced a nominal benefit to customers of $583 Million; $132 Million benefit on a net present value basis, over the depreciable life of the scrubber. Additional net present value benefit of $34.2 Million is attributable to customers associated with the scrubber, as the charges for stranded assets are avoided in the scenario where the scrubber is installed and the station continues to operate.

I. As a result of these analyses, PSNH has concluded that installation of the scrubber, and continued operation of Merrimack Station is the best economic alternative for the benefit of its customers.

CONCLUSION

PSNH has historically provided Clean Air Project status reports to the Legislature and the committees having oversight responsibilities for this project, NHDES, Office of Consumer Advocate, and this Commission; we continue to be ready and willing to meet with the Commission Staff and OCA to discuss the Clean Air Project whenever requested.

PSNH urges the Commission to act promptly in this docket so that the project work can resume without further delay. PSNH is at a critical juncture in the project since some contract work is on hold, while other contracts are not being executed pending the outcome of the Commission's inquiry. Any delay to the project will increase its cost and therefore result in higher costs to customers once the project is in service.

Attachment 1

The Wall Street Journal

Costs to Build Power Plants Pressure Rates

By REBECCA SMITH

May 27, 2008; Page B3

Construction costs for power plants have more than doubled since 2000, according to new index data to be released Tuesday, and inflationary pressures will continue to put the squeeze on electricity prices.

The findings are bad news for consumers and utilities alike, and help explain why power-plant development has become something of a quagmire in the U.S. -- with no type of plant emerging as a reasonably priced option that can meet rising demand for electricity.

The analysis comes in the form of a price index from Cambridge Energy Research Associates Inc., a research and consulting firm in Massachusetts that is a unit of IHS Co. Similar to the consumer-price index, it calculates the cost of building new power plants based on the cost of materials and other factors.

"Costs for labor, materials, equipment and design and engineering -- all are up," said Candida Scott, senior director of cost and technology for CERA. As a result, the cost of building new plants is up 19% from a year ago and up 69% from 2005.

The skyrocketing price tag comes as the world is roiled by surging electricity demand and as it weathers various supply disruptions, some caused by what appear to be changing weather patterns.

In all, CERA says, the construction of new generating capacity that would have cost $1 billion in 2000 would cost $2.31 billion if construction began today.

According to the index, all types of power plants are feeling the pinch. Components and construction materials for nuclear power plants scored the biggest run-up in costs, up 173% -- nearly tripled -- since 2000. Most of that increase has taken place since 2005. Costs for turbines used to generate wind power more than doubled, at 108%, and natural gas-fueled and coal-fired plants saw their capital costs nearly double, up 92% and 78%, respectively.

If anything, the index likely minimizes the rising cost of building power plants, because it doesn't factor in financing costs, and it doesn't include fuel costs. But as prices for coal, natural gas and uranium have risen, they have put added pressure on the operating costs of many companies, and those increases are pushing up electricity prices, too.

The upshot, Ms. Scott said, is that prudent utility regulators should make sure they are basing future decisions on data that are updated frequently, because even calculations less than a year old can be dangerously out of date.

One practical consequence of the inflationary pressures is that they make it harder for plant developers, such as utilities, to look in prices as part of big projects. The longer the time period involved in construction, the bigger the risks inherent in any fixed-price contracts. Instead of paying for "time and materials," many firms are seeking contracts in which prices are tied to various indexes.

In some states, utilities are rolling out big programs to install millions of "smart" electric meters in the belief they will help cut electricity consumption and reduce the need for new power plants. Oncor, a big utility in Texas, last week said it plans to install three million advanced meters on homes and small businesses, giving consumers a tool to help get a handle on electricity use.

The CERA report underscores the tough choices facing utilities and regulators. Both are interested in finding the technology that will be most affordable.

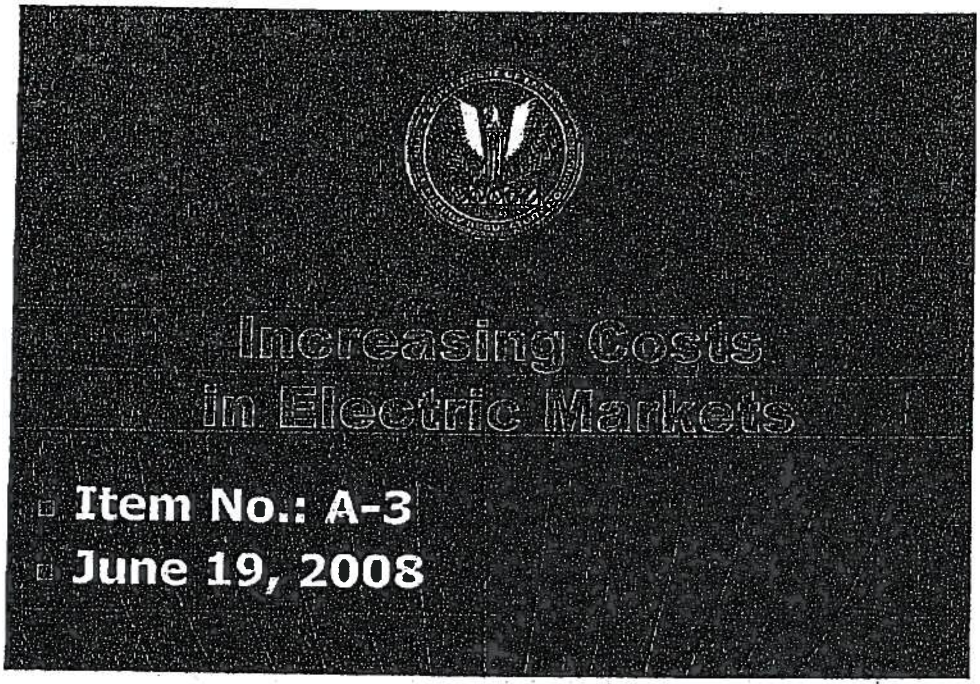
That is especially difficult, since big power plants often remain in service 40 to 60 years.
One commodity whose cost has risen markedly is steel, a important material for building both power-plant structures and power-generating equipment. The cost of iron ore, needed to make steel, rose about 10% in 2007 but has surged 65% in recent months. Shortages of coking coal, also needed to make steel, have been another problem in Australia, a big export country. CERA said steel costs could rise 40% to 60% this year.

A weak dollar also is a factor, since roughly 30% of equipment needed by the U.S. power industry comes from outside the U.S.

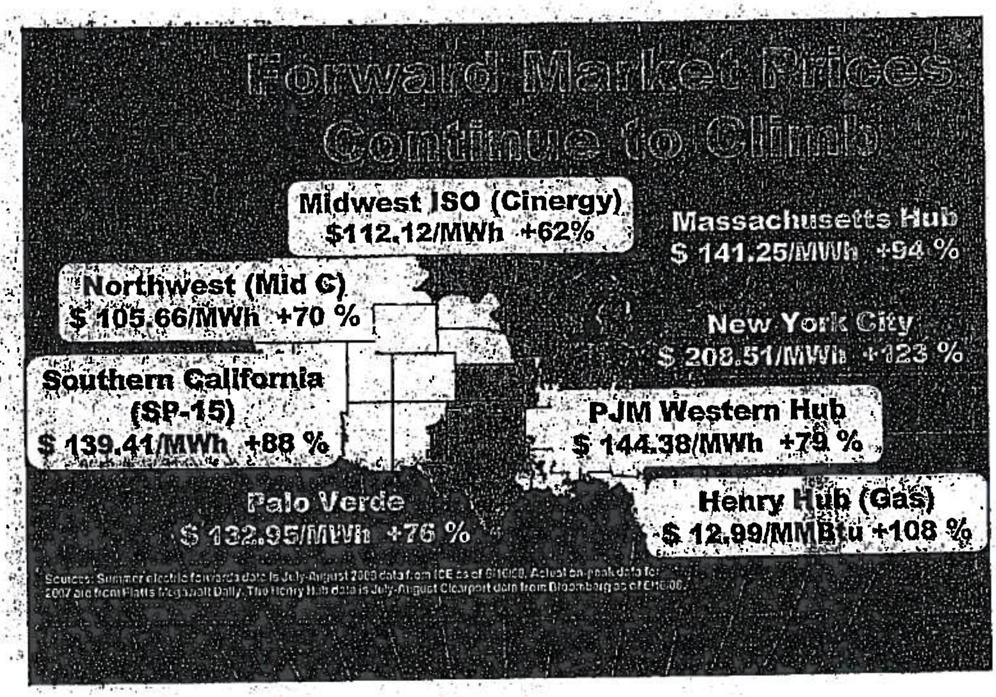
The analysis is of interest because it is difficult to get solid cost data until after plants have been built. Even then, data aren't always available.

Attachment 2

FERC's Office of Enforcement's Report to the FERC Commissioners on Increasing Costs in Electric Markets, presented on June 19, 2008

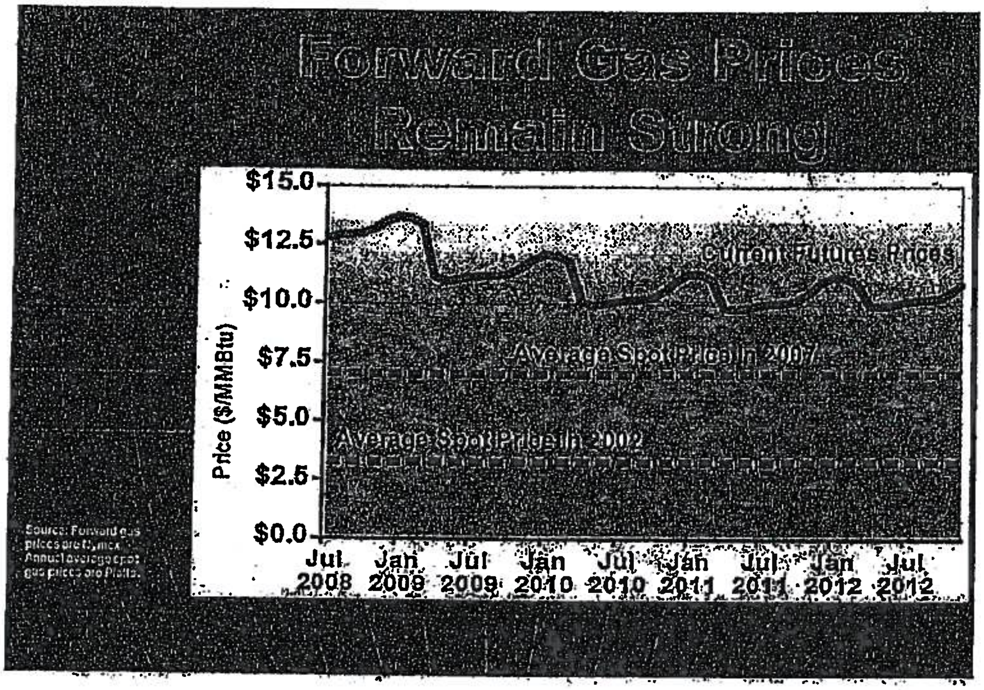


Mr. Chairman and Commissioners, good morning. I am here to present the Office of Enforcement's assessment of likely electricity costs in coming years. This presentation will be posted on the Commission's Web site today.

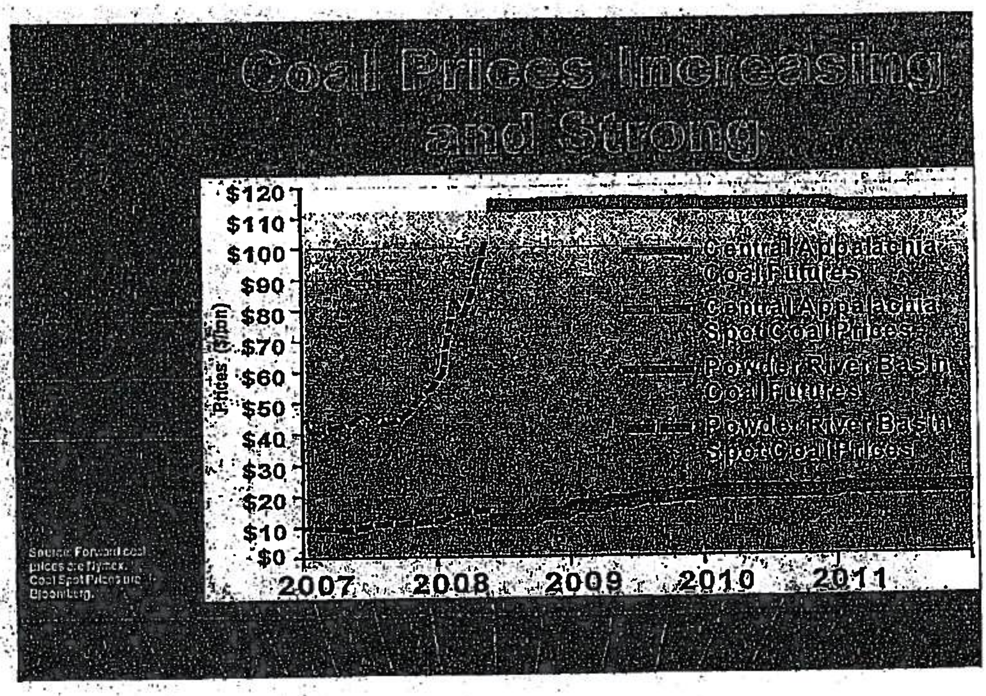


At last month's meeting, we reported that forward market prices for electric power are much higher than the prices we actually experienced last year. This trend is universal around the country. The slide shows the increases in forward prices for July and August as of this week. They have risen further during the last month as natural gas prices have continued to rise.

There is little reason to believe that this summer is unusual. Rather, it may be the beginning of significantly higher power prices that will last for years. The purpose of this presentation is to explain why that is so. The two major factors pushing the costs of electric generation higher are increased fuel costs and increased cost for new construction. These factors affect all parts of the country. That is, higher future prices are likely to affect all regions.



The primary reason for the electric power price increases this year is high fuel prices. All current market indications suggest that they will remain high. Let's look at natural gas, which often determines prices because it is so frequently on the margin. The slide shows futures prices for the next few years. The futures prices are somewhat lower for 2009 than for 2008. Even so, they are a good deal higher for all years than the prices people actually paid last year, and they are much higher than the prices many of us remember from earlier in the decade. The implication is that markets anticipate continuing high prices, even though they know that the United States has seen a significant increase in domestic natural gas production over the last year and a half. The anticipation of further high prices makes more sense when one considers the likely increase in gas demand for generation and the global nature of competition for LNG.



Natural gas is not the only important fuel in setting electric power prices. Coal still powers half of all power produced in the U.S. In some markets – the Midwest and the Southeast, for example – coal is often on the margin and plays a major role in setting average prices over time. The slide shows that the price of one key form of coal – Central Appalachian coal - has risen rapidly over the last year. Forward markets show continuing high prices for Central Appalachian coal for the next three years. This reflects, in part, the growing global market for coal and the relatively weak US dollar. Coal imports are becoming more costly and coal exports more profitable, both of which contribute to higher prices in the United States.

I should mention that other coal prices behave somewhat differently from Central Appalachian coal. For example, a majority of the overall cost for Powder River Basin coal comes from transportation rates and can be more difficult to see. Nonetheless, the implication of the prices we can see is that electric power prices are likely to increase even where coal is on the margin. This may take place somewhat differently from the way natural gas price increases flow through into power prices. Generally, companies buy coal under fairly long term contracts, so there may be a lag before the higher prices show their full effects. But the effects are coming.

Net Natural Gas Generation by Region
(TWh)

Region	2000	2007	Difference
Northeast	66.3	103.9	37.6
RFC	41.0	64.5	23.5
SERC	86.9	150.5	63.6
FRCC	42.0	96.7	54.7
ERCOT	155.9	163.3	7.4
Midwest	44.2	62.8	18.5
WECC-Rockies and SW	28.1	77.6	49.5
WECC-CA and NW	115.4	129.7	14.4

Source: Derived from Energy Velocity (differences due to rounding).

While both natural gas and coal prices have increased rapidly, natural gas is increasingly important in every region of the country. The slide shows that even in regions where coal has historically dominated -- most noticeably in SERC– natural gas usage has grown substantially since 2000, up 63.6 TWh in 2007, more than in any other region. Noticeable increases also occurred in FRCC, which has flexibility to burn either gas or oil at many facilities, and also in the Rockies and Southwest where demand continues to grow considerably.

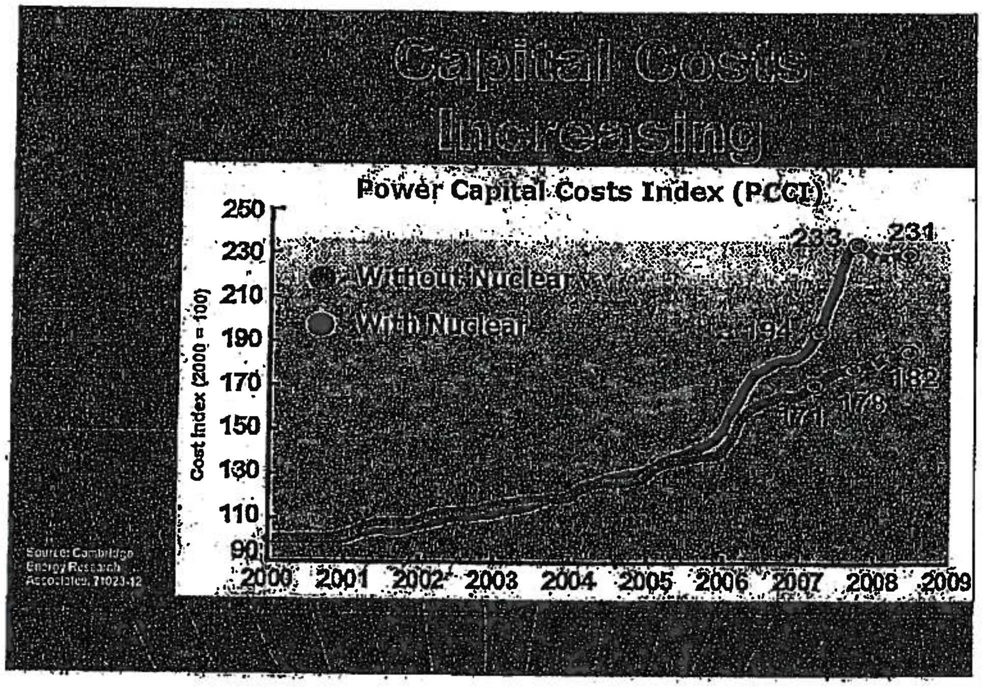
NERC Net Load Projections through 2016

Region	Total Difference (GW)	Percent Change
Northeast	9.7	17
RFC	23.2	13
SERC	28.2	14
FRCC	7.1	15
ERCOT	14.7	24
Midwest	17.2	21
WECC-Rockies and SW	7.6	25
WECC-CA and NW	10.9	10
Total	108.8	14

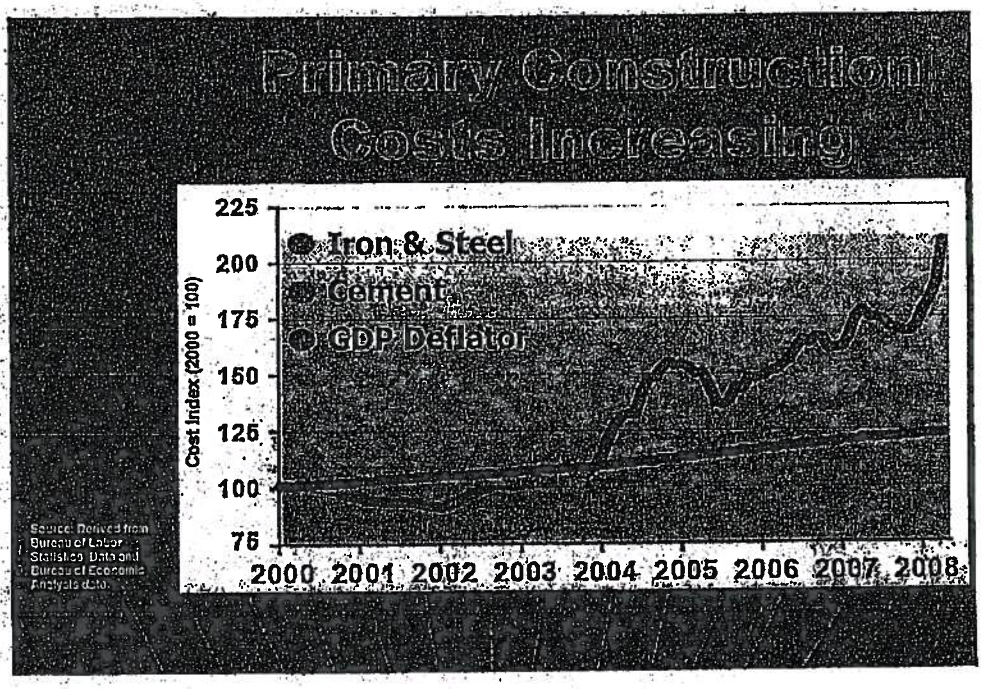
Source: Derived from NERC 2007 Long Term Reliability Assessment, Oct. 2007 and NERC data request, June 200[illegible].

The second major factor that will put upward pressure on electric power prices is the increasing cost of new construction. This effect is particularly important because the country is entering a period when we will need to make substantial new investments, especially in generation.

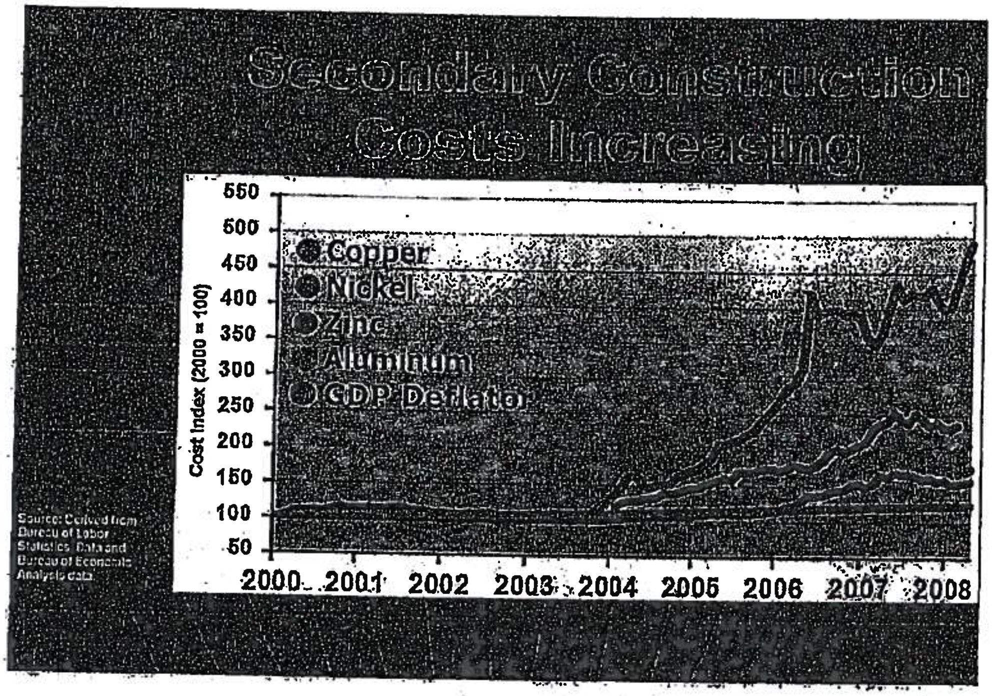
Natural gas fueled most of the last great wave of generation investment, which occurred between 1995 and 2004. In recent years, demand in most regions has gradually caught up with the capacity built around 2000. Looking forward, demand will continue to grow, and the need for new capacity will become ever more acute and ever more widespread. The slide shows NERC's expectation of peak net load growth in different regions for the next 10 years. We at the Commission are not in the business of forecasting, so I would just say this: There are legitimate reasons to be unsure about exactly how much new generation the country will need in the coming years. For one thing, higher prices will themselves discourage some power demand. Nonetheless, a significant level of demand increase seems virtually inevitable. So will be the need to build more capacity.



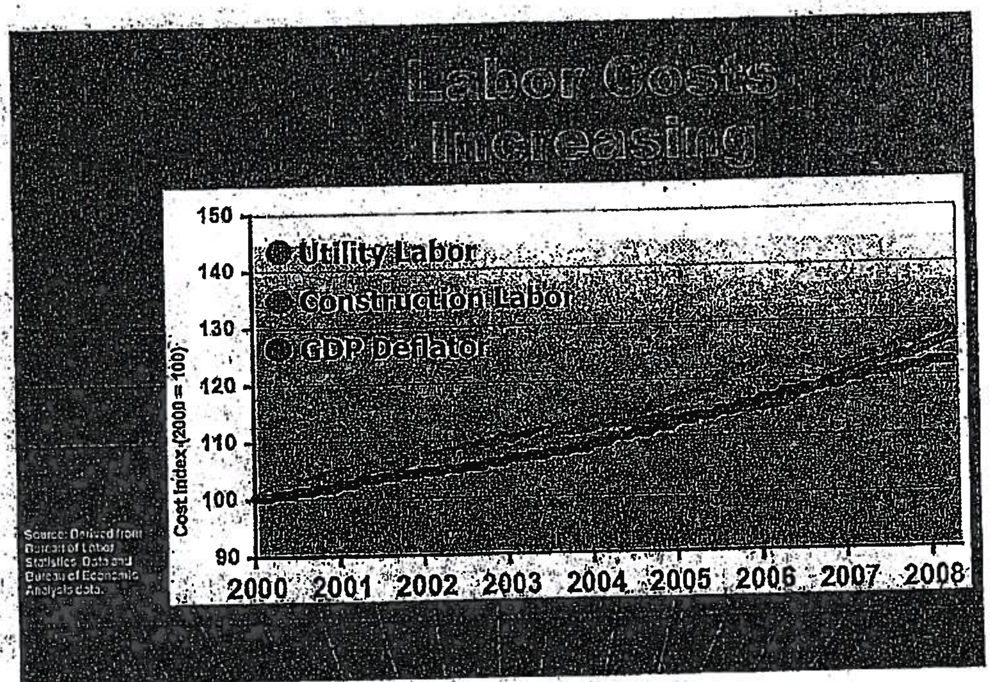
The need for new generation is important because new construction is becoming more expensive – quite aside from fuel price increases. Cambridge Energy Research Associates – CERA – produces an index of costs for the main inputs that go into building new generating plants. The slide shows how that index has almost doubled since 2003. The increase in nuclear plant inputs has risen even faster. Much of this cost increase results from rising global demand for basic materials. Part of it also comes from shortages of people to do key engineering and construction jobs. In any case, the implication is that, we will pay more, not less, for the next round of construction.



Let's look at some of the reasons that CERA's index is rising so rapidly. The slide shows two of the primary construction materials for electric generating plants – concrete is on the blue line and iron and steel on the red line. As you can see, the prices of both have been rising recently – especially steel, which is now more than twice as expensive as it was four years ago. Rising costs for iron and steel will also affect fuel prices for the power industry. For example, natural gas wells and pipelines both use substantial amounts of steel, so natural gas costs will also reflect rising iron and steel prices.

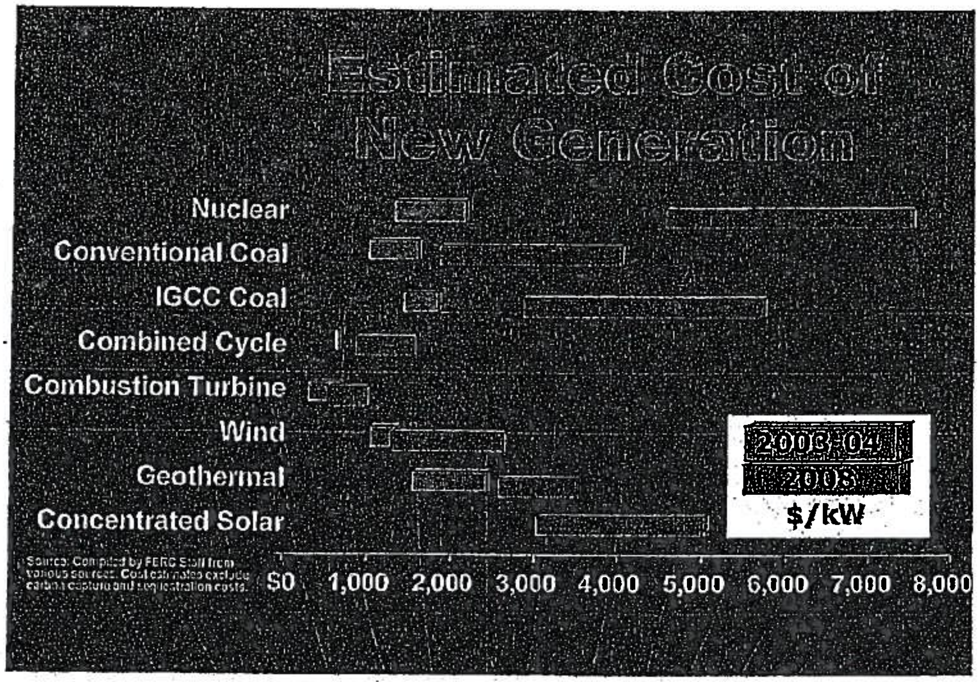


Of course, new generating plants require many other basic commodities. The slide shows the pricing for four key metals that go into generators. As you can see, all of these metals are increasing in price. The one that stands out is copper, up more than five times over the past four years. Indeed, copper is now so valuable there are reports of copper thieves cutting live cables to steal the metal.



Labor costs are also increasing. Perhaps the most frequently cited labor shortage is that for nuclear engineers. It has been a full generation since the nation built its last nuclear plant. Most of the engineers who worked on those plants are near retirement – and many have moved on to other occupations. In fact, the labor shortages are more widespread than just nuclear engineers. The slide shows that there has been about a 27% nominal change in average hourly earnings for both construction labor generally and for non-construction utility labor since 2000, outpacing inflation by over 4% for the same period.

In practice, the American labor market is quite responsive to market forces, so short-term labor shortages tend to be self-correcting over the mid-term. Still, there is no quick way to force several years of education into six months, or decades of experience into a year or two.



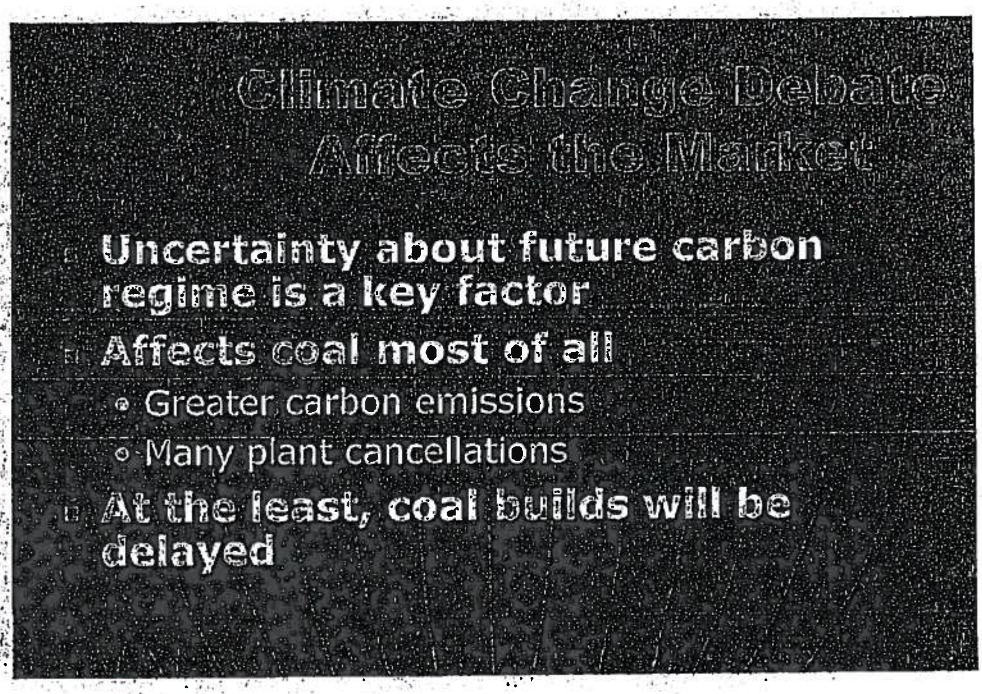
What do all these cost increases mean for the cost of building a new generating plant?

No one knows precisely. It's difficult to get consistent and trustworthy numbers about plant costs, both because they are commercially sensitive and because the assumptions behind them vary greatly. The numbers reflected on the slide come from a variety of sources and include different assumptions about, for example, location or exactly what facilities are included in the estimate. To take one example: Two recent nuclear procurements in South Carolina and Georgia produced cost estimates of $5,100 and $6,400 per kW, respectively, for the same technology. We have been told that most of the difference may be due to different uses of Allowances for Funds Used during Construction – AFUDC.

Despite the difficulties in being precise, the slide represents a good general indication of how capital costs have been changing. If anything, the cost estimates may be lower than the final costs of projects, if input costs continue to rise.

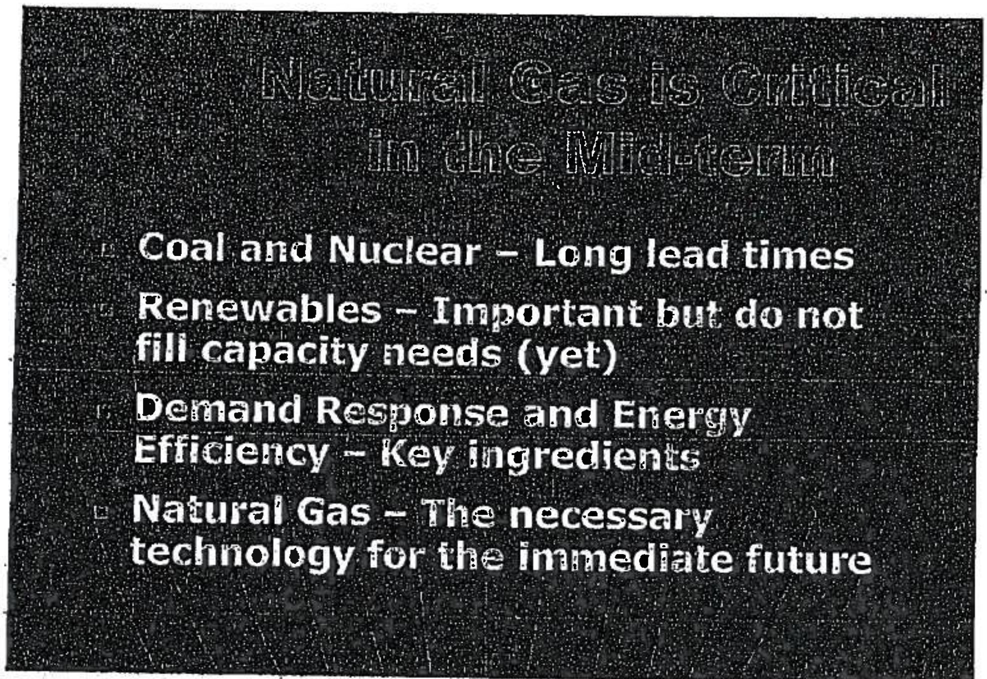
It's also important to remember that these cost estimates cover only capital costs. They do not include fuel costs, which as we've seen earlier will be a large factor for both natural gas and coal-fired plants. To the extent that plants do not have major fuel costs - they may be more competitive over their life cycles than would be suggested just looking at the capital costs. That would affect renewables and, to a degree, nuclear plants.

Similarly, these estimates generally do not include a full accounting of major risk factors, especially those affecting coal and nuclear plants. Both of these technologies have long lead times. That increases the chance that market conditions will change before they are complete and adds to the financial risk of building them. Nuclear plants also have risks associated with both decommissioning and waste fuel disposal. And coal plants have risks associated with the future treatment of greenhouse gases. Of course, relatively new technologies like wind and the new approaches to nuclear also have some risks, simply because they do not have the same track record of more mature technologies.



Climate change has become an increasingly urgent national issue. The debate over how to address carbon dioxide emissions is lively and has already affected how companies think about investments. Until recently, rising natural gas prices made coal plants attractive. However, the national uncertainty about carbon policy has made investing in coal plants more risky. Without carbon capture or sequestration, coal unit emit about four times as much carbon as natural gas combined cycle units per MWh. Since January 2007, 50 coal plants have been canceled or postponed. Only 26 remain under construction.

Whatever the eventual result of the climate change debate, costs of producing power from both coal and natural gas are likely to increase. Moreover, as long as future climate change policy is unclear, market participants will have a considerable disincentive to invest in coal plants. Even when the issues are resolved, it remains an open question how competitive coal-fired generation will be, and it would take another four to eight years to build new coal-fired capacity.



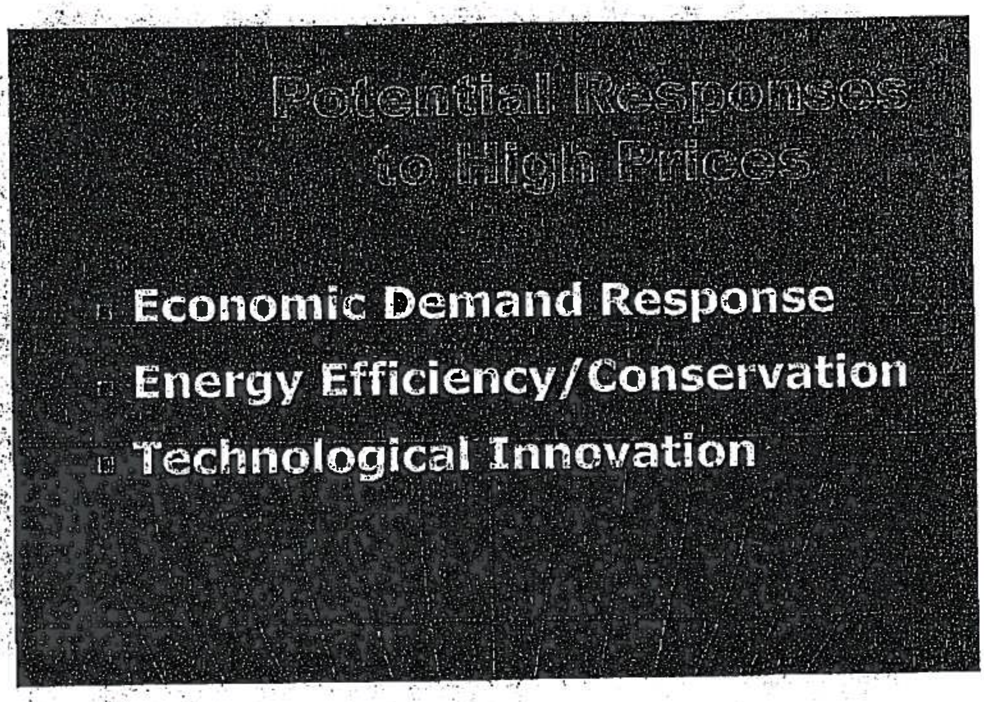
Over the long run, the nation can meet its increasing need for generation in several ways. But for the next few years, the options are more limited, and natural gas will be crucial.

The lead times for both nuclear and coal units mean that they will not supply a significant amount of new capacity for nearly a decade.

Most people expect renewables to supply an increasing proportion of the nation's power. For the next few years, wind will almost certainly account for a large share of generation investment and will account for a growing share of overall generation. Wind power has no fuel costs, and so will generally operate when available. However, wind is a variable, weather-dependent resource. As a result, it will not make up as strong a share of the Nation's capacity needs over the next few years. Other renewables are becoming more competitive. Geothermal power is already an important resource in the west, and concentrated solar is becoming economically attractive in desert areas like the Southwest. But these sources are likely to remain relatively small in the national picture over the next few years.

Both demand response and energy efficiency will be important – I'll talk more about them on the next slide – but they are unlikely to eliminate the need for new capacity.

Overall, the most likely outcome is that natural gas will continue to be the leading fuel for new capacity over the next half decade. For example, the consulting firm, Wood Mackenzie estimates that in a carbon constrained environment, gas consumption for power will increase by 69 % by 2017. That's in addition to the 55% increase we've seen since 2000.



Over the years, we have learned repeatedly that people respond to prices. In the case of electric power, this is likely to take several forms.

First, there is likely to be more demand response. In the simplest terms, high prices at peak will lead some customers – both businesses and others – to prefer to save their money rather than use power. In fact, the first round of demand response may be both the cheapest and fastest way to improve capacity margins on many systems. The best cost estimates for the first rounds of demand response suggest that it should be available for about \$165/kW, far less than any generation side options. The results of ISO-NE's first Forward Capacity Market auction last year corroborates the economic importance of demand response - 7.4 % of the accepted bids were for demand response. However, there are impediments that limit the full use of demand response. For example, most customers do not have the option to respond directly to real-time prices. As a result, they are unlikely to reduce peak consumption as much as they might prefer to if they could take advantage of the price.

Second, customers are likely to be more energy efficient. While few customers see real-time prices, most get an average price over a month. As a result, high prices give them considerable incentive to reduce their overall consumption of power – though no more at peak than at other times. That is, energy efficiency is essentially a substitute for baseload capacity, while demand response is a substitute for peaking capacity. Energy efficiency is also likely to be economically important. Cost estimates show that the first round of energy efficiency may be available for about 3 cents/kWh. At

Continued on next page

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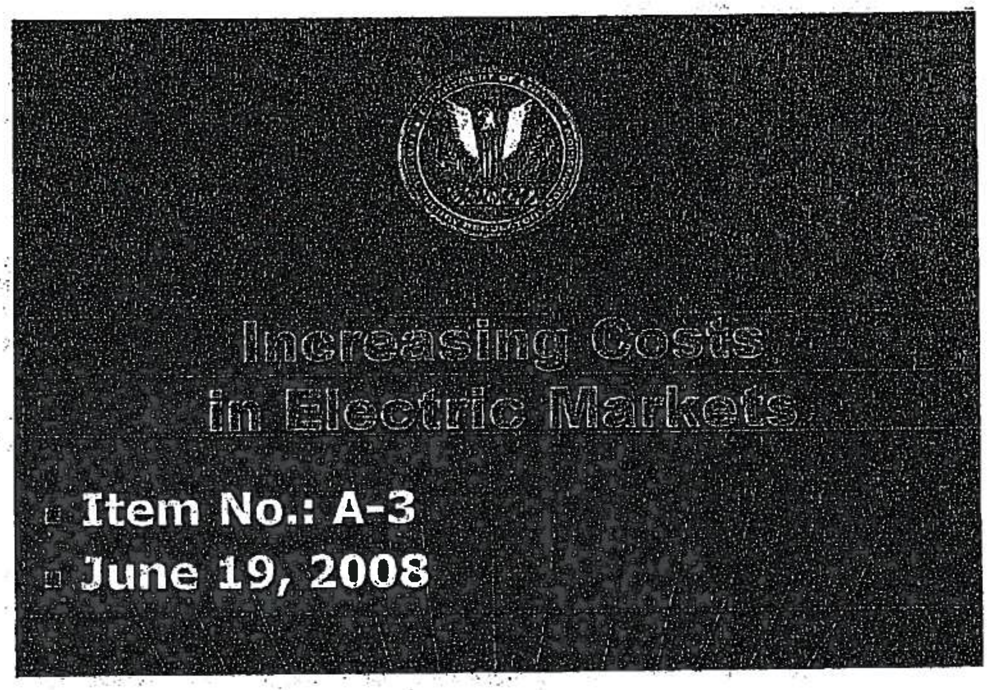
current prices, supplying that same kWh from a combined cycle gas plant would cost 9 cents just for the fuel. Adding to the likelihood of greater energy efficiency is that many states have adopted fairly strong energy efficiency standards.

Third, innovators see higher prices as an opportunity. By the nature of things, it's hard to predict what innovations will succeed. The electric industry has a number of technologies that might take off – including concentrating solar power, hydrokinetic power, and vehicle to grid technologies. In addition, distributed generation is becoming more important, and may continue to do so for both cost and emissions reasons. In other newly competitive industries, such as telecoms and natural gas, innovations have produced large changes, sometimes quickly. Given continuing high electric prices, the electric power industry may see similar results.



That concludes our presentation. We welcome comments and questions.

Confidential Attachment 3

Detailed Project Cost Breakdown

Confidential attachment filed pursuant to "Motion for Protective Order" pursuant to the Commission's August 22, 2008 Secretarial Letter

Attachment 4

DETAILED NET PRESENT VALUE OF REVENUE REQUIREMENTS

Detailed Net Present Value of Revenue Requirements

[illegible]

[redacted]

Attachment 5

SNLi article, July 1, 2008

SNL*i*

SNL Financial

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Power & Coal - Infrastructure Development

Dominion starts construction on Virginia clean coal plant

July 01, 2008 8:14 AM ET

By Adnan Munawar

Dominion Virginia Power said June 30 it began construction on the 585-MW Virginia City Hybrid clean coal plant in Wise County, Va.

Construction of the plant is scheduled to take four years, Dominion said.

The plant is part of Dominion Virginia Power's response to a projected growth in demand for electricity of 4,000 MW from its customers by 2017.

The Virginia Department of Environmental Quality issued the necessary air permits following the unanimous approval June 25 by the State Air Pollution Control Board. The Virginia State Corporation Commission approved the $1.8 billion project on March 31.

The circulating fluidized bed unit will use coal and up to 20% biomass for its fuel. The station will provide nearly 1,000 jobs during construction and require a permanent staff of more than 75 people once it begins operating, the company said.

Dominion Virginia Power is the trade name of Virginia Electric and Power Co., a subsidiary of Dominion Resources Inc.

Attachment 6

SNLi article, June 26, 2008

SNLi

SNLFinancial

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Power & Natural Gas - Operations and Strategy

EIF raises financing to build 620-MW Kleen plant in Connecticut

June 26, 2008 2:16 PM ET

By Jay Hodgkins

Energy Investors Funds Group on June 26 said its United States Power Fund II LP and United States Power Fund III LP have raised construction financing for the Kleen Energy Systems LLC power plant in Middletown, Conn., known as Middletown Kleen.

The financing totaled $985 million of senior secured bank loans and a revolving credit facility, the company said. EIF said it is the majority owner of the project, with the balance owned by White Rock Holdings Associates LLC.

Goldman Sachs & Co. acted as joint lead arranger and sole book runner for senior secured loans raised to help finance the construction of the project. The bank loans were rated as investment grade at BBB- by Fitch Ratings, EIF said.

"With this construction financing in place, we're able to build a first-class power plant to serve the people of Connecticut," said William Corvo of Kleen Energy Systems. "This plant will provide clean, economical power to an area in need of new power generation."

Construction of the project began in February and is expected to be completed in mid-2010, EIF said. The project will be operated by Itochu Corp. subsidiary North American Energy Services and will be managed by Power Plant Management Services.

The Kleen plant will be a 620-MW, combined-cycle natural gas-fired facility. The project won a competitive request for proposals process run by the state of Connecticut and has entered into a 15-year capacity agreement with Northeast Utilities subsidiary Connecticut Light and Power Co. for the electricity produced by the plant.

The project has also finalized a multiyear tolling agreement, EIF said.

THE STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Merrimack Station Scrubber Project
Request for Information

Docket No. DE 08-103

MEMORANDUM OF LAW

Pursuant to the Commission's Secretarial Letter dated August 22, 2008, Public Service Company of New Hampshire ("PSNH" or the "Company") provides this Memorandum of Law concerning the legal mandate placed on the Company by the General Court to install a wet flue gas desulphurization system ("scrubber technology") at PSNH's Merrimack Station in Bow.

On June 8, 2006, "AN ACT relative to the reduction of mercury emissions," 2006 N.H. Laws Chapter 105 (the "Scrubber Law") took effect. By that law, the General Court imposed an unmistakable legislative mandate for PSNH to install and have operational scrubber technology to control mercury emissions at Merrimack Units 1 and 2 no later than July 1, 2013. RSA 125-O:13, I. Three years earlier, in 2003 N.H. Laws, Chapter 21, the legislature had enacted RSA 369-B:3-a. RSA 369-B:3-a authorizes PSNH to modify its generation assets upon a finding that such modifications are "in the public interest of retail customers of PSNH to do so." In its Secretarial Letter, the Commission requested this Memorandum of Law to address "the nature and extent of the Commission's authority relative to the Merrimack Station scrubber project" in light of the statutory requirements contained in RSA 125-O:11, *et seq.*, and RSA 369-B:3-a.

Subject to acknowledged constitutional limitations, the regulation of utilities and the setting of appropriate rates to be charged for public utility products and services is the unique province of the legislature. *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 313 (1989); *The Minnesota Rate Cases*, 230 U.S. 352, 433 (1913); *LUCC v. Public Serv. Co. of N.H.*, 119 N.H. 332, 340 (1979). The Public Utilities Commission ("PUC") derives its authority from powers delegated by the legislature. *Appeal of Richards*, 134 N.H. 148, 158 (1991).

The "nature and extent of the Commission's authority" has been clearly set forth in numerous New Hampshire Supreme Court decisions. *Petition of Boston & Maine Railroad*, 82 N.H. 116 (1925); *State of New Hampshire v. New Hampshire Gas & Electric Co.*, 86 N.H. 16 (1932); *H.P. Welch Co. v. State*, 89 N.H. 428 (1938); *Blair and Savoie v. Manchester Water Works*, 103 N.H. 505 (1961); *State v. New England Telephone & Telegraph Co.*, 103 N.H. 394 (1961); *Appeal of Public Service Co.*, 122 N.H. 1062 (1982). *See also, The Manchester Press Club v. State Liquor Comm'n*, 89 N.H. 442 (1938).

As early as 1925, the Court held:

> ***The public service commission is an agency of limited powers and authority.*** While the legislature may delegate to such an agency certain of its own powers and authority, ***the exercise of such delegation does not extend beyond expressed enactment or its fairly implied inferences.*** The establishment of such an agency is of a special rather than general character, and ***power and authority not granted are withheld.***

Boston & Maine Railroad, id. at 116 (emphases added).

The Court, citing to this 1925 precedent, re-affirmed the limited authority of the PUC in *Appeal of Public Service Co.*:

> The PUC is a creation of the legislature and as such is endowed with ***only*** the powers and authority which are ***expressly granted or fairly implied by statute.*** *Petition of Boston & Maine Railroad*, 82 N.H. 116, 116, 129 A. 880, 880 (1925). ***Consequently, the authority of the PUC...is limited to that specifically delegated or fairly implied by the legislature and may not be derived from other generalized powers of supervision.***

Appeal of Public Service Co., *id.* at 1066 (emphases added).

Recently, the Commission itself noted these restrictions on its power and authority. In *Re RCC Minnesota, Inc.*, 88 NH PUC 611 (2003), discussing the Commission's authority to regulate cellular carriers, the Commission found:

> The New Hampshire Supreme Court has held that "[t]he PUC is a creation of the legislature and as such is endowed with only the powers and authority which are expressly granted or fairly implied by statute." *Appeal of Public Service Company of New Hampshire*, 122 NH 1062, 1066 (1982). Consequently, ***the Commission must look to its statutory authority to determine whether it has jurisdiction*** over cellular providers. RSA 362:6 expressly states that it does not. A cellular provider is not a public utility, and its "services shall not be subject to the jurisdiction of the public utilities commission pursuant to this title." RSA 362:6. ***We therefore must conclude that the Commission does not have jurisdiction over any cellular carrier because the New Hampshire legislature specifically removed cellular carriers from the jurisdiction of this Commission.***

Re RCC Minnesota, Inc., at 615 (emphases added). *See also, Re Congestion on the Telephone Network Caused by Internet Traffic*, 89 NH PUC 173, 175 (2004) ("It is a well-established principle that this Commission possesses only those powers that are granted to it by the legislature.")

These precedents clearly and consistently note that "the regulation of utilities...is the unique province of the legislature"; the Commission "derives its authority from powers delegated by the legislature"; "[t]he...commission is an agency of limited powers and authority"; and, "the authority of the PUC...is limited to that specifically delegated or fairly implied by the legislature and may not be derived from other generalized powers of supervision." These holdings detail the limits of the Commission's authority and form the bases for any discussion concerning the nature and extent of the Commission's authority relative to the Merrimack Station scrubber project.

The Scrubber Law, codified at RSA 125-O:11 through 125-O:18, is clear, straightforward, and unambiguous in its mandate, as set forth in the first words of the statute:

> *Statement of Purpose and Findings. The general court finds that:*
>
> *I. It is in the public interest to achieve significant reductions in mercury emissions at the coal-burning electric power plants in the state as soon as possible.* The requirements of this subdivision will prevent, at a minimum, 80 percent of the aggregated mercury content of the coal burned at these plants from being emitted into the air by no later than the year 2013. *To accomplish this objective, the best known commercially available technology shall be installed at Merrimack Station no later than July 1, 2013.*

RSA 125-O:11, I (emphases added).

The General Court provided unequivocal notice of the Scrubber Law's intent in eight such findings in the law's *Statement of Purpose and Findings*:

> I. *It is in the public interest to achieve significant reductions in mercury emissions at the coal-burning electric power plants in the state as soon as possible.* The requirements of this subdivision will prevent, at a minimum, 80 percent of the aggregated mercury content of the coal burned at these plants from being emitted into the air by no later than the year 2013. *To accomplish this objective, the best known commercially available technology shall be installed at Merrimack Station no later than July 1, 2013.*
>
> II. *The department of environmental services has determined that the best known commercially available technology is a wet flue gas desulphurization system, hereafter "scrubber*

> ***technology," as it best balances the procurement, installation, operation, and plant efficiency costs with the projected reductions in mercury and other pollutants from the flue gas streams of Merrimack Units 1 and 2.*** Scrubber technology achieves significant emissions reduction benefits, including but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter, and improved visibility (regional haze).
>
> III. ***After scrubber technology is installed at Merrimack Station,*** and after a period of operation has reliably established a consistent level of mercury removal at or greater than 80 percent, the department will ensure through monitoring that that level of mercury removal is sustained, consistent with the proven operational capability of the system at Merrimack Station.
>
> IV. To ensure that an ongoing and steadfast effort is made to implement practicable technological or operational solutions to achieve significant mercury reductions prior to the construction and operation of the scrubber technology at Merrimack Station, the owner of the affected coal-burning sources shall work to bring about such early reductions and shall be provided incentives to do so.
>
> V. ***The installation of scrubber technology will not only reduce mercury emissions significantly but will do so without jeopardizing electric reliability and with reasonable costs to consumers.***
>
> VI. ***The installation of such technology is in the public interest of the citizens of New Hampshire and the customers of the affected sources.***
>
> VII. Notwithstanding the provisions of RSA 125-O:1, VI, the purchase of mercury credits or allowances to comply with the mercury reduction requirements of this subdivision or the sale of mercury credits or allowances earned under this subdivision is not in the public interest.
>
> VIII. ***The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of cost, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components.***

RSA 125-O:11 (emphases added).

The Scrubber Law's mandate that a scrubber shall be installed at Merrimack Station is detailed in the statutory provisions contained in its "Statement of Purpose and Findings." In RSA 125-O:13, I, the General Court unequivocally requires PSNH to install a scrubber at Merrimack Station within a set timeframe:

> I. *The owner [PSNH] shall install and have operational scrubber technology to control mercury emissions at Merrimack Units 1 and 2 no later than July 1, 2013. The achievement of this requirement is contingent upon obtaining all necessary permits and approvals from federal, state, and local regulatory agencies and bodies; however, all such regulatory agencies and bodies are encouraged to give due consideration to the general court's finding that the installation and operation of scrubber technology at Merrimack Station is in the public interest.* The owner shall make appropriate initial filings with the department and the public utilities commission, if applicable, within one year of the effective date of this section, and with any other applicable regulatory agency or body in a timely manner.

(Emphasis added).

The General Court could not be clearer regarding the purpose and intent of the Scrubber Law. ***PSNH shall install a scrubber at Merrimack Station as soon as possible.*** This mandate is binding not just on PSNH, but also on the Commission. As noted earlier, "the authority of the PUC…is limited to that specifically delegated or fairly implied by the legislature and may not be derived from other generalized powers of supervision." *Appeal of Public Service Co., supra,* 122 N.H. at 1066. In the Scrubber Law, the General Court has:

I. Found that "It is in the public interest to achieve significant reductions in mercury emissions at the coal-burning electric power plants in the state as soon as possible."

II. Mandated that scrubber "technology shall be installed at Merrimack Station no later than July 1, 2013."

III. Found that "the best known commercially available technology is a wet flue gas desulphurization system, hereafter 'scrubber technology,' as it best balances the procurement, installation, operation, and plant efficiency costs with the projected reductions in mercury and other pollutants from the flue gas streams of Merrimack Units 1 and 2."

IV. Found that "Scrubber technology achieves significant emissions reduction benefits, including but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter, and improved visibility (regional haze)."

V. Found that "The installation of scrubber technology will not only reduce mercury emissions significantly but will do so without jeopardizing electric reliability and with reasonable costs to consumers."

VI. Found that "The installation of such technology is in the public interest of the citizens of New Hampshire and the customers of the affected sources."

VII. And declared that "The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of cost, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components."

The Scrubber Law does not delegate authority to the Commission to second-guess the mandates and findings of the General Court. There is absolutely no implication within the Scrubber Law that the mandate to install a scrubber at Merrimack Station as soon as possible can be delayed, conditioned, or eliminated in its entirety, by the Commission.

Interpretation of the Scrubber Law is not difficult. Just a few days ago, the Supreme Court issued its most recent holdings on statutory interpretation:

> We are the final arbiters of the legislative intent as expressed in the words of the statute considered as a whole. *State v. Langill*, 157 N.H. ___, ___ (decided April 4, 2008). We begin by examining the language of the statute, *State v. Whittey*, 149 N.H. 463, 467 (2003), and ascribe the plain and ordinary meaning to the words used, *Langill*, 157 N.H. at ___. We interpret legislative intent from the statute as written and will not consider what the legislature might have said or add language that the legislature did not see fit to include. *Id.* We also interpret a statute in the context of the overall statutory scheme and not in isolation. *Id.* If a statute is ambiguous, however, we consider legislative history to aid our analysis. *Whittey*, 149 N.H. at 467. Our goal is to apply statutes in light of the legislature's intent in enacting

> them, and in light of the policy sought to be advanced by the entire statutory scheme. *Id.*

State v. Dansereau, ___ N.H. ___ (August 15, 2008, *slip op.* at 2); *See also, Oulette v. Town of Kingston*, ___ N.H. ___ (August 15, 2008, *slip op.*).

In the case of the Scrubber Law, the overall statutory scheme includes not just the contents of 2006 N.H. Laws 105, but the entirety of RSA Chapter 125-O, the state's Multiple Pollution Reduction Program. Enacted during the 2002 legislative session as "AN ACT relative to additional emissions reductions from existing fossil fuel burning steam electric power plants," (2002 N.H. Laws, Chapter 130), RSA 125-O:1 contains additional findings by the General Court that are part of the overall statutory scheme leading to the Scrubber Law. The Legislature's findings include: a finding that "scientific advances have demonstrated that adequate protection of public health, environmental quality, and economic well-being - the 3 cornerstones of New Hampshire's quality of life - requires additional, concerted reductions in air pollutant emissions." RSA 125-O:1, I; a finding "that protecting New Hampshire's high quality-of-life environment by reducing air pollutant emissions returns substantial economic benefit to the state through avoided health care costs; greater tourism resulting from healthier lakes and improved vistas; more visits by fishermen, hunters, and wildlife viewers to wildlife ecosystems, and a more productive forest and agricultural sector." RSA 125-O:1, IV; a finding "that aggressive further reductions in emissions of sulfur dioxide (SO2), oxides of nitrogen (NOx), mercury, and carbon dioxide (CO2) must be pursued." RSA 125-O:1, III; and, a finding "that substantial additional reductions in emissions of SO2, NOx, mercury, and CO2 must be required of New Hampshire's existing fossil fuel burning steam electric power plants.." RSA 125-O:1, V.

When viewed with the Supreme Court's stated goal of applying statutes in light of the legislature's intent in enacting them, and in light of the policy sought to be advanced by the entire statutory scheme, there is no doubt what was intended by passage of the Scrubber Law. The public interest findings of the General Court in RSA 125-O:1 overwhelmingly dictate the policy objectives; the Scrubber Law was intended to expeditiously implement these objectives via installation of the scrubber as quickly as possible.

The language of the Scrubber Law is clear. Ascribing the "plain and ordinary meaning to the words used" in the Scrubber Law leaves no doubt that the General Court has mandated installation of a scrubber at Merrimack Station as soon as possible. The intent of the Scrubber Law is obvious and apparent from the statute as written. The overall statutory scheme and the policy sought to be advanced is obvious and unwaivering: "The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of cost, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components."

The Supreme Court has also discussed the importance of the General Court's use of the word "shall," as used in the Scrubber Law. (A scrubber "***shall*** be installed at Merrimack Station no later than July 1, 2013." RSA 125-O:11, I. The requirements of the Scrubber Law "***shall*** be viewed as an integrated strategy of non-severable components." RSA 125-O:11, VIII. "The owner ***shall*** install and have operational scrubber technology to control mercury emissions at Merrimack Units 1 and 2 no later than July 1, 2013." RSA 125-O:13, I. "Total mercury emissions from the affected sources ***shall*** be at least 80 percent less on an annual basis than the baseline mercury input, as defined in RSA 125-O:12, III, beginning on July 1, 2013." RSA 125-O:13, II. In *State v. Johanson*, 156 N.H. 148, 151 (2007), the Court noted:

> "The use of the word 'shall' is generally regarded as a command; although not controlling, it is significant as indicating the intent that the statute is mandatory. This is especially so where the purpose of the statute is to protect private rights." *McCarthy v. Wheeler*, 152 N.H. 643, 645, 886 A.2d 972 (2005).

Similarly, in *City of Rochester v. Corpening*, 153 N.H. 571, 574 (2006) the Court held:

> "The intention of the Legislature as to the mandatory or directory nature of a particular statutory provision is determined primarily from the language thereof." *Appeal of Rowan*, 142 N.H. 67, 71, 694 A.2d 1002 (1997) (quotation and citation omitted). The general rule of statutory construction is that "the word 'may' makes enforcement of a statute permissive and that the word 'shall' requires mandatory enforcement." *Town of Nottingham v. Harvey*, 120 N.H. 889, 895, 424 A.2d 1125 (1980).

As recently as July 25th of this year, the Supreme Court reiterated this principle of statutory construction. Discussing the Legislature's use of the word "shall" in RSA 402-C:34, the Court cited to *Rowan, supra,* and held that "having used the word 'shall,' the legislature is presumed to have intended setoff under RSA 402-C:34 to be mandatory rather than discretionary." *In the Matter of the Liquidation of The Home Insurance Company*, ___ N.H. ___, *slip op. at* 10 (July 25, 2008).

The use of the word "shall" in the Scrubber Law emphasizes the Legislature's intent that installation of a scrubber at Merrimack Station is "commanded" and is "mandatory." Indeed, within the Scrubber Law, the General Court used the word "shall" sixty times! There can be no doubt of the mandatory and unequivocal direction expressed in the Scrubber Law.

When the Scrubber Law is analyzed using the Supreme Court's statutory interpretation rules, the General Court's meaning, intent, and command is clear. If there was any ambiguity, which there is not, the Court has indicated that legislative history would be used to aid in the statute's analysis. The Scrubber Law's legislative history is equally clear and unambiguous:

> SCIENCE, TECHNOLOGY AND ENERGY
>
> HB 1673-FN, relative to the reduction of mercury emissions.
>
> MAJORITY: OUGHT TO PASS WITH AMENDMENT. MINORITY: OUGHT TO PASS WITH AMENDMENT.
>
> Rep. Roy D. Maxfield for the Majority of Science, Technology and Energy: ***This bill provides for at least an 80% reduction of mercury emissions from coal-fired power plants by requiring the installation of a scrubber technology no later than July 1, 2013 and provides economic incentives for earlier installation timeframes and greater reduction in emissions.*** The committee amendment provides for annual progress reports from Public Service of New Hampshire (PSNH) and also cost recovery language. ***This legislation is a result of months of collaborative work by PSNH, the Department of Environmental Services, the Governor's office, multiple environmental groups, members of the committee and other stakeholders.*** The scrubber technology not only will reduce mercury by at least 80%, it will dramatically reduce SO2 emissions. ***Our committee held multiple work sessions and all had an opportunity to present their views.*** A comprehensive review of the timeframe was conducted by two members of the committee who concluded that the 2013 date is appropriate. ***It is in the best interests of PSNH to achieve early reductions for mercury*** and they are proceeding with a US Department of Energy (DOE) grant to accomplish this objective. ***This bill has consensus support from the Governor and stakeholders, and has wide bipartisan support in the General Court. The bill achieves the primary objectives of reasonable reductions, in a reasonable timeframe, at a reasonable cost to electricity users.*** Vote 13-2.
>
> Rep. Gene F. Andersen for the Minority of Science, Technology and Energy: ***The bill provides for significant mercury reductions from facilities operated by Public Service of New Hampshire (PSNH) by 2013.*** Some testimony indicated that an optimal permit

> and construction schedule could provide a 2011 completion for mercury removal equipment; thereby providing the necessary and desired reductions of mercury and other pollutants during that two year period. ***The minority felt the 2011 date should be utilized for implementation of the mercury reduction requirement*** and provide for extensions beyond that date if and only if PSNH was unable to complete by 2011 due to circumstance beyond its control.

House Calendar, Vol. 28, No. 22, February 17, 2008, p. 1280 (emphases added).

Moreover, the Analysis accompanying the Scrubber Law reads:

> ANALYSIS
>
> This bill provides for an 80 percent reduction of mercury emissions from coal-burning power plants by requiring the installation of scrubber technology no later than July 1, 2013 and provides economic incentives for earlier installation and greater reductions in emissions.

2006 N.H. Laws, Chapter 105.

The Scrubber Law's legislative history and Analysis echo the mandates found in the plain language of the law itself - - the bill requires the installation of scrubber technology no later than July 1, 2013. The only difference of opinion between the legislative majority and minority was on the schedule for the mandated installation of the scrubber - - the minority wanted the scrubber installed earlier - - a goal that is being materially hindered by the Commission's creation of this docket.

The Secretarial Letter states that there is "a potential conflict between" the Scrubber Law and RSA 369-B:3-a. PSNH finds no such conflict. The Scrubber Law uses plain and ordinary words which mandate that a scrubber "shall be installed at Merrimack Station no later than July 1, 2013." RSA 369-B:3-a, enacted during the 2003 legislative session, reads:

> 369-B:3-a Divestiture of PSNH Generation Assets. The sale of PSNH fossil and hydro generation assets shall not take place before April 30, 2006. Notwithstanding RSA 374:30, subsequent to April 30, 2006, PSNH may divest its generation assets if the commission finds that it is in the economic interest of retail customers of PSNH to do so, and

> provides for the cost recovery of such divestiture. ***Prior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the commission finds that it is in the public interest of retail customers of PSNH to do so***, and provides for the cost recovery of such modification or retirement.

(Emphasis added).

The "potential conflict" noted in the Secretarial Letter appears to be whether PSNH is required to obtain a Commission finding under RSA 369-B:3-a that the modification of Merrimack Station by the installation of a scrubber "is in the public interest of retail customers of PSNH" before such installation may proceed. As noted in *Appeal of Pinetree Power, Inc.*, 152 N.H. 92, 97 (2005), "By the plain language of the statute [RSA 369-B:3-a], the public interest standard for modification is broader than just economic interests." The General Court has weighed and ruled on the broader public interest and found that the Scrubber Law's requirements "represent a careful, thoughtful balancing of cost, benefits, and technological feasibility...." RSA 125-O:11, VIII.

Due to the mandatory language and express findings of the General Court contained in the Scrubber Law, there is no need nor authority for the Commission to render an additional and duplicative public interest finding under RSA 369-B:3-a prior to the installation of the scrubber. Any such proceeding under RSA 369-B:3-a would be held to determine only one thing - - whether it is "in the public interest of retail customers of PSNH" to modify Merrimack Station by installation of a scrubber. ***That precise finding has already been made by the General Court*** - - "The installation of [scrubber] technology is in the public interest of the citizens of New Hampshire and the customers of the affected sources." RSA 125-O:11, VI. As the General Court has already made the requisite RSA 369-B:3-a finding, the

Commission lacks authority to contravene this Legislative finding and there is no need for a separate and redundant Commission finding. Such a reading of the law is consistent with General Court's express statements of purpose and findings contained in the Scrubber Law. Statutes are to be interpreted "not in isolation, but in the context of the overall statutory scheme." *State v. Farrow*, 140 N.H. 473, 475 (1995); *Appeal of Ashland Elec. Dept.*, 141 N.H. 336, 340 (1996); *Pinetree Power, id.* at 96.

By finding that "The installation of [scrubber] technology is in the public interest of...the customers of [PSNH]," the General Court has removed from the Commission any authority to reach a contrary finding. Recall, "the authority of the PUC...is limited to that specifically delegated or fairly implied by the legislature and may not be derived from other generalized powers of supervision." *Appeal of Public Service Co., id.* The General Court has not delegated authority to the Commission to determine whether installing a scrubber at Merrimack Station is in the public interest, nor is such authority fairly implied. That public interest finding has been made, and is clearly and definitively embodied in the law.

It should be noted that two of the sponsors of the Scrubber Law were also sponsors of 2003 N.H. Laws, Chapter 21, the law creating RSA 369-B:3-a. Senators Green and Odell both sponsored Senate Bill 170 during the 2003 legislative session and House Bill 1673-FN during the 2006 legislative session. It is inconceivable that these two Senators would sponsor legislation in 2006 finding that installation of scrubber technology at Merrimack Station is in the public interest of PSNH's customers (the precise finding required in their earlier 2003 law), yet would delegate to the Commission the authority and duty to make (or contradict) that same finding.

Any other reading of the interplay between the Scrubber Law and RSA 369-B:3-a would create the very conflict implied in the Secretarial Letter. In the event that there was a conflict between two statutes, the Supreme Court has held:

> When a conflict exists between two statutes, the later statute will control, especially when the later statute deals with a subject in a specific way and the earlier enactment treats that subject in a general fashion. 2A C. D. Sands, Sutherland Statutes and Statutory Construction § 51.05 (4th ed. 1973). However, as we noted in *Ingersoll v. Williams*, 118 N.H. 135, 138, 383 A.2d 1119, 1121 (1978), decided this day, implied repeal of former statutes is a disfavored doctrine in this State. *See also State v. Miller*, 115 N.H. 662, 348 A.2d 345 (1975); *Opinion of the Justices*, 107 N.H. 325, 221 A.2d 255 (1966). The party arguing a repeal by implication must demonstrate it by evidence of convincing force. *Opinion of the Justices, id.* at 328, 221 A.2d at 257. If any reasonable construction of the two statutes taken together can be found, this court will not find that there has been an implied repeal. *State v. Miller supra; Public Serv. Co. v. Lovejoy Granite Co.*, 114 N.H. 630, 325 A.2d 785 (1974).

Board of Selectmen of Merrimack v. Planning Board of Merrimack, 118 N.H. 150 (1978).

More recently the Court re-affirmed this principle:

> "It is a well-recognized rule of statutory construction that where one statute deals with a subject in general terms, and another deals with a part of the same subject in a more detailed way, the latter will be regarded as an exception to the general enactment where the two conflict." *State v. Bell*, 125 N.H. 425, 432, 480 A.2d 906 (1984). We also note that RSA 161:4, VI was enacted in 1991, while RSA chapter 151-E was enacted in 1998. "When a conflict exists between two statutes, the later statute will control, especially when the later statute deals with a subject in a specific way and the earlier enactment treats that subject in a general fashion." *Petition of Public Serv. Co. of N.H.*, 130 N.H. 265, 283, 539 A.2d 263 (1988) (quotations omitted), appeal dismissed, 488 U.S. 1035, 109 S. Ct. 858, 102 L. Ed. 2d 983 (1989).

Bel Air Associates v. Dept. of Health and Human Services, 154 N.H. 228, 233 (2006).

Of the two laws in question, the Scrubber Law is the later statute, enacted during the 2006 legislative session versus the 2003 enactment for RSA 369-B:3-a. In addition, RSA 369-B:3-a deals with undefined, potential modifications of PSNH's generation assets in a general way. The Scrubber Law contains specific findings and mandates. In accordance with the Court's holding in *Bel Air Associates*, the explicit directions provided in the Scrubber Law must be regarded as controlling over the general RSA 369-B:3-a enactment.

The instant situation is similar to the facts facing the Supreme Court in *Petition of Public Service Co. of N.H.*, 130 N.H. 265 (1988), cited in *Bel Air, supra*. In *Petition of Public Service Co. of N.H.*, the Court dealt with the power of the Commission to grant PSNH an emergency rate increase per RSA 378:9 during the construction of the Seabrook nuclear plant despite the enactment of the so-called "anti-CWIP" law, RSA 378:30-a. The Court noted that the emergency rate statute "grants the commission broad discretionary powers." *Petition of PSNH* at 283. "The anti-CWIP statute, on the other hand, restricts the commission's discretionary powers in the ratemaking process." *Id.* The Court then held:

> The one statute grants the commission general ratemaking powers under emergencies, and the other, enacted after the first, restricts the commission's discretion when determining rates. "When a conflict exists between two statutes, the later statute will control, especially when the later statute deals with a subject in a specific way and the earlier enactment treats that subject in a general fashion." *Board of Selectmen v. Planning Bd.*, 118 N.H. 150, 152, 383 A.2d 1122, 1124 (1978). RSA 378:30-a was enacted after the emergency statute. The anti-CWIP statute is unconditional in its prohibition, and makes no exceptions for emergencies.

Id.

Once again, PSNH faces a situation involving the enactment of a more recent, specific statute and an older statute of general application. Like the anti-CWIP law, the Scrubber Law, enacted after RSA 369-B:3-a, restricts the Commission's discretion. It also deals with the subject of modifying Merrimack

Station by the installation of a scrubber in a specific way, versus the general supervisory authority found in the earlier statute. Under the Court's holding in *Petition of PSNH*, the Scrubber Law's mandate for the installation of a scrubber at Merrimack Station and finding of such action to be in the public interest are controlling and binding upon the Commission.

The legislative mandates contained in the Scrubber Law are made even more apparent when the Scrubber Law is compared to the language in RSA Chapter 362-C, "Reorganization of Public Service Company of New Hampshire." As in the Scrubber Law, RSA Chapter 362-C begins with a legislative "Declaration of Purpose and Findings." RSA 362-C:1. Notably, the RSA 362-C:1 findings include a grant of authority to the Commission:

> ...the public utilities commission should be authorized to determine whether a proposed agreement relating to the reorganization of Public Service Company of New Hampshire and, upon receipt of required regulatory approvals, the acquisition of Public Service Company of New Hampshire by Northeast Utilities, would be consistent with the public good and whether the rates for electric service to be established in connection with the reorganization are just and reasonable and should be approved.

RSA 362-C:1, IV. In RSA Chapter 362-C, the General Court specifically delegated authority to the Commission to make a determination whether the cited agreement "would be consistent with the public good." RSA 362-C:3. In the Scrubber Law, no such delegation of authority to the Commission is included; the General Court itself has determined that installation of a scrubber "is in the public interest of the citizens of New Hampshire and the customers of the affected sources." Had the Legislature intended to delegate such authority to the Commission, it certainly knew how to do so, as it had done in the past in RSA Chapter 362-C for another matter involving the Commission's regulatory authority concerning PSNH. *See also, Cannata v. Town of Deerfield*, 132 N.H. 235, 243 (1989) (...the legislature knew how to include real property in a definition when it intended to do so.); *Barry v. Amherst*, 121 N.H. 335, 339 (1981) (The express language of RSA 36:23 (Supp. 1979) demonstrates that the legislature knew how to provide for automatic approval when that was its intention.).

PSNH notes that in a recent e-mail, the Commission's former general counsel, citing to RSA 125-O:13, I, indicated that the General Court's findings in the Scrubber Law were not binding upon the Commission, but were only to be afforded "due consideration." The complete wording of RSA 125-O:13, I, reads:

> I. The owner shall install and have operational scrubber technology to control mercury emissions at Merrimack Units 1 and 2 no later than July 1, 2013. The achievement of this requirement is contingent upon obtaining ***all necessary permits and approvals*** from federal, state, and local regulatory agencies and bodies; however, ***all such regulatory agencies and bodies are encouraged to give due consideration to the general court's finding that the installation and operation of scrubber technology at Merrimack Station is in the public interest. The owner shall make appropriate initial filings with the department and the public utilities commission, if applicable***, within one year of the effective date of this section, and with any other applicable regulatory agency or body in a timely manner.

For all the reasons set forth earlier, the Scrubber Law eliminates any need for a Commission determination under RSA 369-B:3-a; it is just not applicable and is not a necessary approval. Indeed, the creation of any such proceeding before the Commission (including the instant proceeding) would frustrate the General Court's specific finding that "It is in the public interest to achieve significant reductions in mercury emissions at the coal-burning electric power plants in the state as soon as possible." RSA 125-O:13, I. Any delays in the project will cause increases in the ultimate price tag to be borne by PSNH's customers as costs of materials and labor continue to escalate, AFUDC continues to accrue, and the possibility to achieve early emissions reduction credits under RSA 125-O:16 evaporates. In the only other proceeding held under RSA 369-B:3-a, a total of 16 months elapsed between PSNH's initial filing and the achievement of a final, unappealable decision. NHPUC Docket No. DE 03-166, *PSNH Petition for Authority to Modify Schiller Station; Pinetree Power, id.* It is inconceivable that the General Court intended to subject the scrubber project to delays arising from a similar proceeding, given the "significant emissions reduction benefits, including but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter, and improved visibility (regional haze)" (RSA 125-O:11, II) and incentives (that would benefit PSNH's retail customers) provided for early completion of the scrubber (RSA 125-O:16).

Notwithstanding the clarity of the mandate and intent of the Scrubber Law, if any ambiguity in the meaning of RSA 125-O:13, I, remained, the principles of statutory construction established by the Supreme Court, *supra*, would be applied. Recall the Court's direction in *Dansereau, supra*:

> We also interpret a statute in the context of the overall statutory scheme and not in isolation. If a statute is ambiguous, however, we consider legislative history to aid our analysis. Our goal is to apply statutes in light of the legislature's intent in enacting them, and in light of the policy sought to be advanced by the entire statutory scheme.

(Internal citations omitted).

The "overall statutory scheme" set forth in RSA 125-O:13, "Compliance," is clear, when these remaining provisions of that section are considered:

I. *The owner shall install and have operational scrubber technology* to control mercury emissions at Merrimack Units 1 and 2 *no later than July 1, 2013.*

II. *Total mercury emissions from the affected sources shall be at least 80 percent less* on an annual basis than the baseline mercury input, as defined in RSA 125-O:12, III, beginning on July 1, 2013.

IV. If the net power output (as measured in megawatts) from Merrimack Station is reduced, *due to the power consumption requirements or operational inefficiencies of the installed scrubber technology*, the owner may invest in capital improvements at Merrimack Station that increase its net capability...

V. Mercury reductions achieved *through the operation of the scrubber technology* greater than 80 percent shall be sustained insofar as the proven operational capability of the system, as installed, allows.

VI. The purchase of mercury emissions allowances or credits from any established emissions allowance or credit program shall not be allowed for compliance with *the mercury reduction requirements of this chapter.*

VII. If the mercury reduction requirement of paragraph II is not achieved in any year after the July 1, 2013 implementation date, and *after full operation of the scrubber technology,....*

VIII. If the mercury reduction requirement of paragraph II is not achieved by the owner in any year after the July 1, 2013 implementation date *despite the owner's installation and full operation of scrubber technology....*

IX. The owner shall report by June 30, 2007 and annually thereafter, to the legislative oversight committee on electric utility restructuring, established under RSA 374-F:5, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee, on *the progress and status of complying with the requirements of paragraphs I and III, relative to achieving early reductions in mercury emissions and also installing and operating the scrubber technology including any updated cost information.* The last report required shall be after the department has made a determination, under paragraph V, on the maximum sustainable rate of mercury emissions reductions *by the scrubber technology.*

RSA 125-O:13 (emphases added).

There can be no mistake that in enacting the Scrubber Law the Legislature intended that scrubber technology ***shall*** be installed at Merrimack Station. Without installation of the scrubber, the entirety of RSA 125-O:13 is made ineffective, as the provisions contained therein all anticipate and are based upon the mandated scrubber installation. Since the "goal is to apply statutes in light of the legislature's intent in enacting them, and in light of the policy sought to be advanced by the entire statutory scheme," (*Dansereau, id.*), there can be no doubt regarding the meaning of the Scrubber Law.

The "necessary permits and approvals" referenced in RSA 125-O:13, I, do not include a proceeding under RSA 369-B:3-a. Examples of such "necessary permits and approvals" include zoning laws, building permits, Federal Aviation Administration approvals, environmental permits, and the like, all of which PSNH is in the process of obtaining in a timely manner. The mandate to install a scrubber, and the General Court's finding that such installation is in the public interest of PSNH's retail customers, does not dictate ***how*** the scrubber is installed, just that it ***must*** be installed. PSNH is still required to ensure that the scrubber design meets traditional safety, environmental, and other building standards. *Cf.*, RSA 674:30, which provides that a public utility "may petition the public utilities commission to be exempted from the operation of any local ordinance, code, or regulation enacted under this title [LXIV]." RSA 674:30, III. This statute continues "The public utilities commission, following a public hearing, ***may*** grant such an exemption if it decides that the present or proposed situation of the structure in question is reasonably necessary for the convenience or welfare of the public...." *Id.* Note that the Legislature made such a grant of exemption permissive, by use of the word "may" instead of "shall" - - it is such determinations to which "regulatory agencies and bodies are encouraged to give due consideration to the general court's finding that the installation and operation of scrubber technology at Merrimack Station is in the public interest."

The nature and extent of the Commission's authority concerning the scrubber project is set forth in the Scrubber Law itself. RSA 125-O:18, "Cost Recovery" states in part, "If the owner is a regulated utility, the owner shall be allowed to recover all prudent costs of complying with the requirements of this subdivision in a manner approved by the public utilities commission." The section continues by specifying that during ownership and operation of Merrimack Station by PSNH, "such costs shall be recovered via the utility's default service charge." By this section, the General Court has clearly established the Commission's role and authority regarding the scrubber project. When the scrubber project is completed, the Commission has the authority to review the prudence of PSNH's design and installation of the scrubber. The Commission does not have the authority to second-guess the General Court's decision mandating the installation of the scrubber.

Until the scrubber project is finished, the General Court has reserved to itself the power and authority to oversee the project. This reservation of authority is found in RSA 125-O-13, IX:

> The owner shall report by June 30, 2007 and annually thereafter, to the legislative oversight committee on electric utility restructuring, established under RSA 374-F:5, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee, on the progress and status of complying with the requirements of paragraphs I and III, relative to achieving early reductions in mercury emissions and also installing

> and operating the scrubber technology including any updated cost information. The last report required shall be after the department has made a determination, under paragraph V, on the maximum sustainable rate of mercury emissions reductions by the scrubber technology.

Such a reservation of authority by the General Court concerning the progress, status, and cost of complying with the Scrubber Law is yet another clear indication of the law's intent to negate the need for a RSA 369-B:3-a proceeding in this matter.

PSNH is confident that up to the initiation of the instant proceeding, it was diligently pursuing and complying with the legal mandates contained in 2006 N.H. Laws, Chapter 105, the Scrubber Law, by moving forward rapidly with the installation of scrubber technology at Merrimack Station. The legal mandates and requirements of the statute are set forth in plain and ordinary language, clearly expressing the legislature's intent and the policy sought to be advanced by the entire statutory scheme. This statutory scheme limits the powers and authority of the Commission concerning the installation of scrubber technology at Merrimack Station to a determination of the manner for the recovery of all prudent costs of complying with the requirements of this law.

PSNH urges the Commission to expeditiously act in this inquiry so that the Company may resume the commitment of capital and manpower necessary to install a wet flue gas desulphurization system ("scrubber technology," RSA 125-O:12, V) at its Merrimack Station as mandated by law.

Respectfully submitted this 2nd day of September, 2008.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

By: ______________________________

Robert A. Bersak
Assistant Secretary and Assistant General Counsel
Public Service Company of New Hampshire
780 N. Commercial Street
Manchester, NH 03101-1134

603-634-3355
Bersara@PSNH.com

CERTIFICATE OF SERVICE

I certify that on this date I caused the attached Memorandum of Law to be served pursuant to N.H. Code Admin. Rule Puc 203.11.

September 2, 2008

Robert Buseh

THE STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Merrimack Station Scrubber Project
Request for Information

Docket No. DE 08-103

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE'S
MOTION FOR PROTECTIVE ORDER
RE: BID AND CONTRACT INFORMATION

Pursuant to RSA 91-A:5,(IV)(Supp.) and N.H. Code Admin. Rules Puc § 203.08, Public Service Company of New Hampshire ("PSNH" or the "Company") hereby requests protective treatment for certain information requested in the Commission's Secretarial Letter of August 22, 2008. In that letter the Commission requested that PSNH supply, *inter alia*, "a comprehensive status report on its installation plans, a detailed cost estimate for the project, and an analysis of the effect on energy service rates if Merrimack Station were not in the mix of fossil and hydro facilities operated by PSNH." A portion of this information is confidential, commercial, or financial information exempted from public disclosure under RSA 91-A:5.

In support of its Motion for Protective Order, PSNH says the following:

1. In order to prepare a comprehensive status report and a detailed cost estimate for the project, PSNH must rely on the results of progress made to date in preparing the different portions of the scrubber project for the commencement of construction efforts. There are several "islands" of work which are being negotiated with bidders before a final contract is executed for each portion of the project. These areas of the project are still in various stages of bidding or negotiations with bidders, contractors and subcontractors. The bids offered have all been made under a strictly confidential request for proposal process in order to protect the information from public disclosure. Even final contract terms and designs have been designated by the bidders and contractors as proprietary and subject to confidentiality terms to be included in the final agreements. Conclusions and summaries of data can be

made publicly available; however, the specific data contains information that is confidential, commercial, or financial information which the Commission may protect from public disclosure under RSA 91-A:5, IV.

2. If this information were to be made public, the contractors' proprietary information would be available to their competitors damaging their future ability to bid competitively on other contracts. Many vendors may withdraw from this project altogether if they cannot rely on customary business practices which include maintaining the confidentiality of contract terms. PSNH may have difficulty in attracting potential contractors in the future if there is a perception that their bids or confidential contract terms will be publicly disclosed.

3. The Commission must use a balancing test in order to weigh the importance of creating an open record of this proceeding with the harm from disclosure of confidential, financial or competitive information. "Under administrative rule Puc 204.06, the Commission considers whether the information, if made public, would likely create a competitive disadvantage for the petitioner; whether the customer information is financially or commercially sensitive, or if released, would likely constitute an invasion of privacy for the customer; and whether the information is not general public knowledge and the company takes measures to prevent its' dissemination." *Re Northern Utilities, Inc.*, 87 NH PUC 321, 322, Docket No. DG 01-182, Order No. 23,970 (May 10, 2002). Contracts with suppliers and confidential bidding information are routinely granted confidential treatment by the Commission. *Unitil Energy Systems*, 91 NH PUC 145, 150 (2006).

4. The limited benefits of publicly disclosing the information requested in the status report on the project's detailed cost estimate do not outweigh the harm done by disclosing the information. The ability to finalize contracts with vendors for this project and future projects may be jeopardized.

WHEREFORE, PSNH respectfully requests the Commission to issue an order preventing the public disclosure of the detailed cost estimate for the project, and to order such further relief as may be just and equitable.

Respectfully submitted this 2nd day of September, 2008.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

By:________________________

Robert A. Bersak
Assistant Secretary and Assistant General Counsel
Public Service Company of New Hampshire
780 N. Commercial Street
Manchester, NH 03101-1134

603-634-3355
Bersara@PSNH.com

CERTIFICATE OF SERVICE

I certify that on this date I caused the attached Motion for Protective Order to be served pursuant to N.H. Code Admin. Rule Puc 203.11.

September 2, 2008

ROBERT BERSAK
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Docket #: 08-103-1 Printed: September 02, 2008

FILING INSTRUCTIONS: PURSUANT TO N.H. ADMIN RULE PUC 203.02(a)(1)

WITH THE EXCEPTION OF DISCOVERY, FILE 7 COPIES (INCLUDING COVER LETTER) WITH:

DEBRA A HOWLAND
EXEC DIRECTOR & SECRETARY
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

PURSUANT TO N.H. ADMIN RULE 203.09 (d), FILE DISCOVERY

DIRECTLY WITH THE FOLLOWING STAFF

RATHER THAN WITH THE EXECUTIVE DIRECTOR

LIBRARIAN
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

BULK MATERIALS:

Upon request, Staff may waive receipt of some of its multiple copies of bulk materials filed as data responses. Staff cannot waive other parties' right to receive bulk materials.

NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

AMANDA NOONAN
CONSUMER AFFAIRS DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

Docket #:
Printed: 9/2/2008

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-03
Dated: 08/24/2012
Q-TC-007

Witness: Terrance J. Large
Request from: TransCanada

Question:
Reference the September 2, 2008 report by PSNH to the Commission in DE 08-103, page 15, Section IV.D, please describe the process used to examine the forward market for natural gas delivered to New England and please provide copies of any and all documentation in PSNH's possession or the possession of any of its agents related to this analysis. Please explain when and why this examination was done.

Response:
Please see the response to TC-03, Q-TC-006. This analysis was performed in the summer of 2008 using NYMEX data from June 11, 2008. This analysis was done to support an updated status report filing to the NHPUC.

N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-11
Witness William H. Smagula
DO NOT REMOVE FROM FILE

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-03
Dated: 08/24/2012
Q-TC-009
Page 1 of 1

Witness: Terrance J. Large
Request from: TransCanada

Question:
Reference the September 2, 2008 report by PSNH to the Commission in DE 08-103, page 15, Section IV.E please explain how PSNH arrived at the year 2012 price of $11 per MMbtu to be used as the first year price of natural gas and provide any and all documentation in PSNH's possession or the possession of any of its agents related to the choice of this price.

Response:
The 2012 price of $11/MMBtu for natural gas was selected by reviewing the NYMEX futures prices available in the summer of 2008. As shown on page 22 of the September 2, 2008 report to the NHPUC, the futures prices were $11/MMBtu in 2012.

Long
EXHIBIT NO. 11
9/16/13
S. ROBIDAS

Public Service
of New Hampshire

780 N. Commercial Street, Manchester, NH 03101

Public Service Company of New Hampshire
P. O. Box 330
Manchester, NH 03105-0330
(603) 634-2701

Hallsr@psnh.com

A Northeast Utilities Company

Stephen R. Hall
Manager, NH Revenue Requirements

N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-12
Witness William H. Smagula
DO NOT REMOVE FROM FILE

August 7, 2013

By Electronic Mail Only

Suzanne Amidon
Staff Attorney
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301

Re: **DE 11-250; Public Service Company of New Hampshire Investigation of Scrubber Costs and Cost Recovery**

Dear Attorney Amidon:

I enclose Public Service Company of New Hampshire's Responses to TS-02 in the above-captioned proceeding. The confidential attachment to Q-031 will be provided under separate cover.

Very truly yours,

Stephen R. Hall

Stephen R. Hall
Manager, NH Revenue Requirements

Enclosures
cc : Discovery Service List (by electronic mail only)

Log
EXHIBIT NO. 12
9/16/13
S. ROBIDAS

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-001
Page 1 of 4

Witness: Michael L. Shelnitz
Request from: New Hampshire Public Utilities Commission Staff

Question:
Please update TS-01, Q-TECH-001 Lines 6-12 from the temporary rates portion of 11-250. Please include in the format the projected 12 months. Please include any assumptions needed to answer the question.

Response:
The update for lines 6 through 12 using current actual and projected data is as follows:

		($000s)	
(Line 6)	January thru June 2013 under recovery	$14,488	
(Line 7)	July thru December 2013 under recovery		$14,120
(Line 8)	Total 2013 under recovery	$28,608	
(Line 9)	3 Yr. Amortization of 12/31/12 Scrubber under recovery	$16,709	
(Line 10)	Total to be recovered	$45,317	
(Line 11)	2014 ES MWH sales	3,751,685	
(Line 12)	2014 ES Rate Increment - Scrubber	1.21 cents/kWh	
	Existing Scrubber Temporary Rate	0.98 cents/kWh	
	Total Proposed ES Scrubber Rate	2.19 cents/kWh	

Additionally, please see pages 2 through 4 of this response for the detail associated with 2013.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
2013 ENERGY SERVICE RATE CALCULATION
MERRIMACK SCRUBBER IMPACT
(Dollars in 000s)

Summary of Actual/Projected Energy Service Cost For January 2013 Through December 2013		Merrimack Scrubber Total Costs	Reference
Merrimack Scrubber O&M, Fuel and Avoided SO2 Cost	$	8,319	Page 3
Merrimack Scrubber Depreciation Expense		15,555	Page 3
Merrimack Scrubber Property Tax Expense		215	Page 3
Merrimack Scrubber Return on Rate Base		38,839	Page 4
Actual and Projected 2013 Merrimack Scrubber Cost	$	62,927	
Actual and Projected 2013 Merrimack Scrubber Revenue		38,341	
Projected 2013 Merrimack Scrubber Under-Recovery	$	24,586	
Return		4,021	
2013 Merrimack Scrubber Under-Recovery with Return	$	28,608	

Amounts shown above may not add due to rounding.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
2013 ENERGY SERVICE RATE CALCULATION
MERRIMACK SCRUBBER O&M, DEPRECIATION AND PROPERTY TAXES
(Dollars in 000s)

Merrimack Scrubber O&M, Depr. & Taxes	January 2013 Actual	February 2013 Actual	March 2013 Actual	April 2013 Actual	May 2013 Actual	June 2013 Actual	July 2013 Projected	August 2013 Projected	September 2013 Projected	October 2013 Projected	November 2013 Projected	December 2013 Projected	Total
Merrimack Scrubber Operation & Maintenance Cost	$ 274	$ 347	$ 398	$ 171	$ 317	$ 234	$ 274	$ 347	$ 398	$ 171	$ 317	$ 234	$ 3,478
Merrimack Scrubber Fuel related Cost	804	989	827	454	244	239	864	782	673	520	488	670	7,415
Merrimack Scrubber Avoided SO2 Cost	(378)	(389)	(319)	(11)	(35)	(154)	(378)	(389)	(319)	(11)	(35)	(154)	(2,874)
Merrimack Scrubber Depreciation Cost	1,295	1,298	1,295	1,295	1,295	1,295	1,297	1,297	1,297	1,297	1,297	1,297	15,565
Merrimack Scrubber Property Taxes (1)	18	18	18	18	18	18	18	18	18	18	18	18	215
Total Merrimack Scrubber O&M, Fuel, SO2, Depr. and Taxes	$ 2,013	$ 2,251	$ 2,017	$ 1,937	$ 1,839	$ 1,832	$ 2,065	$ 2,066	$ 2,066	$ 2,066	$ 2,065	$ 2,065	$ 24,069

(1) Merrimack Scrubber related property tax impact represents the projection of the non-exempt portion of the project

Amounts shown above may not add due to rounding.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
2013 ENERGY SERVICE RATE CALCULATION
MERRIMACK SCRUBBER RETURN ON RATE BASE
(Dollars In 000s)

		January 2013 Actual	February 2013 Actual	March 2013 Actual	April 2013 Actual	May 2013 Actual	June 2013 Actual	July 2013 Projected	August 2013 Projected	September 2013 Projected	October 2013 Projected	November 2013 Projected	December 2013 Projected	Total
10	Merrimack Scrubber													
11	Return on Rate Base													
14	Rate base													
15	Net Plant	$ 396,291	$ 394,834	$ 393,540	$ 392,338	$ 391,209	$ 389,783	$ 383,486	$ 387,189	$ 385,892	$ 384,595	$ 383,298	$ 382,001	
17	Working Capital Allow. (45 days of O&M)	429	429	429	429	429	429	429	429	429	429	429	429	
18	Deferred Taxes	(29,933)	(31,354)	(32,775)	(33,800)	(34,825)	(35,850)	(55,175)	(60,676)	(61,373)	(58,801)	(61,186)	(62,157)	
19	Total Rate Base (L15 thru L18)	366,788	363,909	361,201	358,967	356,813	354,362	333,740	326,942	324,948	326,223	322,541	320,273	
21	Average Rate Base (prev + curr month)	366,151	365,347	362,555	360,084	357,890	355,587	344,051	330,341	325,945	325,086	323,882	321,407	
22	x Return	0.9237%	0.9237%	0.9237%	0.9258%	0.9258%	0.9258%	0.9536%	0.9536%	0.9536%	0.9536%	0.9536%	0.9536%	
23	Merrimack Scrubber Return (L21 x L22)	$ 3,382	$ 3,375	$ 3,349	$ 3,334	$ 3,313	$ 3,292	$ 3,281	$ 3,150	$ 3,108	$ 3,100	$ 3,080	$ 3,065	$ 38,839

Amounts shown above may not add due to rounding.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-002

Witness: William H. Smagula
Request from: TransCanada

Question:
Please file an unredacted version of confidential Attachment 3, Bates page 36, dated September 2, 2008 in Docket DE 08-103.

Response:
Attached find a updated copy of Attachment 3, Detailed Project Cost Breakdown, previously provided confidential in PSNH's filing dated September 2, 2008.

Summary Cost Estimate
Merrimack Station Clean Air Project
(Cost in Actual Year $*)

/	Total - Prior to 2007	Total 2007	Actual Jan-Apr 2008	Estimated May-Dec 2008	Total 2008	Total 2009	Total 2010	Total 2011	Total 2012	Total 2013	Total (Proj)
NU Labor	71,567	318,675	206,306	772,508	978,814	1,207,955	1,402,400	1,670,000	1,060,000	0	6,709,411
Material	0	7,995	19,954	1,130,000	1,149,964	11,400,000	18,720,000	2,040,000	750,000	0	34,067,949
Contractor Labor											
Owner Costs	12,564	230,330	840,567	1,971,514	2,812,081	4,445,000	3,493,200	1,981,800	510,000	0	13,484,675
URS - Indirect Costs **	0	957,071	3,208,048	7,000,000	10,206,048	20,000,000	20,000,000	16,000,000	7,600,000	0	74,663,119
URS - FGD System	0	0	0	10,005,486	10,005,486	14,007,680	42,023,041	24,013,118	10,005,486	0	100,054,809
URS - Chimney System	0	0	0	1,308,330	1,308,330	6,541,650	3,924,990	0	1,308,330	0	13,083,300
URS - Material Handling System	0	0	0	4,482,875	4,482,875	7,172,600	20,621,225	8,069,175	4,482,875	0	44,828,750
URS - Wastewater Treatment System	0	0	0	1,500,000	1,500,000	1,200,000	8,100,000	2,700,000	1,500,000	0	15,000,000
URS - Balance of Plant	0	0	49,830	5,700,000	5,749,830	23,800,000	25,300,000	9,600,000	3,300,000	0	67,949,830
Subtotal Contractor Labor	12,564	1,187,401	4,096,445	31,963,205	36,064,650	77,166,930	123,462,456	62,563,791	28,606,691	0	329,064,483
Outside Services	728,889	228,755	274,340	495,400	769,740	245,000	250,000	166,000	120,000	0	2,497,384
Employee Expenses	2,874	9,733	11,510	26,000	36,510	10,000	10,000	10,000	5,000	0	84,117
Vehicles	0	34	0	100	100	100	100	100	100	0	534
Fees & Payments	0	0	0	10,000	10,000	2,995,000	6,340,000	3,265,000	1,165,000	0	12,765,000
Rents & Leases	0	0	10,222	7,560	17,782	12,984	0	0	0	0	30,766
Contingency	0	0	0	0	0	2,000,000	2,000,000	3,000,000	3,000,000	0	10,000,000
TOTAL DIRECT COSTS	815,893	1,752,593	4,618,778	34,408,773	39,027,851	95,037,909	151,184,956	72,703,891	34,896,791	0	395,219,644
Indirect Costs	8,343	37,992	13,919		[redacted]						
AFUDC	47,677	72,468	81,800		[redacted]						
TOTAL COST	871,913	1,863,053	4,714,497	34,408,773	41,326,431	101,315,736	165,578,732	96,462,159	49,803,046	0	467,221,069

* Includes Escalation
Estimated: [illegible]
Based on Substantial Completion 6-30-12
** URS - Indirect Costs (in millions) include Construction Services = $6.5, URS = $39.3, Growth = $4.4, Escalation = $23.0, Contingency = $14.7

afudc Check

[redacted]

	Total - Prior to 2007	Total 2007	Actual Jan-Apr 2008	Estimated May-Dec 2008	Total 2008	Total 2009	Total 2010	Total 2011	Total 2012	Total 2013	Total (Proj)
Direct + Indirect	824,236	1,790,585	4,632,697	34,408,773	39,825,044	96,116,834	162,502,699	74,129,206	35,580,706	0	400,789,309
Cumulative		2,662,498	6,495,749	43,874,187	42,560,010	140,178,230	297,879,832	385,086,071	442,990,730	0	
AFUDC	47,677	72,458	4,632,697	34,408,773	1,501,387	5,198,903	13,076,033	22,332,952	14,222,339	0	56,451,760

~~CONFIDENTIAL~~

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-003

Witness: William H. Smagula
Request from: TransCanada

Question:
For all documents that are no longer confidential, please provide them.

Response:
In a review of the electronic filings in docket 08-103, 11-215 (Temporary Rates), and 11-250 (Scrubber prudence review), PSNH finds four items to be confidential.

- Item 1- As requested and provided in TS-02, Q-TECH-002, Attachment 3 - Detailed Project Cost Breakdown is no longer confidential
- Item 2- Response to CLF01-003 filed 7/9/12 includes redactions which remain confidential (Vendor required redactions to the Vendor contract)
- Item 3- Response to TC04- 009 filed 9/14/12 includes redactions which remain confidential (non-winning bidders as approved by Commission order)
- Item 4- Response to TS-01, Q-Tech-001 filed 10/5/12 remains confidential (GP contract with PSNH regarding sale of gypsum)

Confidential material in the physical data room continues to be available for review by parties who sign the non-disclosure agreement. The data room will remain open until the end of the discovery phase of this docket.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-004

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-005, Appendix E. This is the first indication that there was an increase in the Sargent Lundy estimate. Is this update from 2005 to 2006 a reflection of inflation? If so, are there any other increases that are built into these costs other than just inflation?

Response:
See the attached comparison of Sargent & Lundy's 2005 and 2006 estimate provided to Jacobs and in reponse TC-02, Q-TC-005. The total project cost estimate for 2005 and 2006 remained the same. The first cost estimate was developed as part of a multi-scope effort (Phase I) to validate results of earlier work considering the installation of a wet flue gas desulfurization system (wet FGD), to define the scope and configuration options of a wet FGD installation, and to develop a multi-pollutant control plan. The second cost estimate was developed based on preliminary information for selected aspects of design for a wet FGD system (Phase II). See TS-02, Q-TECH-035.

Item	PSNH/URS Item Description	PSNH/URS June 2008 Estimate	PSNH/S&L 2005 Estimate	PSNH/S&L 2005 Estimate	Discussion of Differences
1	Program Manager (Responsible for engineering, design, procurement services, scheduling, project management, construction management, start up, commissioning, testing oversight, and operator training services)	39.3	18.1	145.0	The S&L estimate was an inclusive number including the 4 major islands, program management, balance of plant, etc. with no specific defined scope; while the URS estimate was based on complete detailed scope of work.
2	FGD Island (design, fabricate, procure, test, package, ship, store and handle, erection, and commission FGD System) (turnkey EPC Island includes all structures and equipment required for a complete functioning FGD System including process/mechanical systems, instrumentation and control systems, electrical systems, and structural systems - excluding foundations)	100.0	75.0	Included in 1	1.) No specific mercury or SO3 guarantees required with S&L. Guarantees required with URS., 2.) Market pressure on scrubber cost due to CAIR., 3.) URS includes increased redundancy for tankage.
3	Chimney Island (design, supply, and construct a free standing reinforced concrete chimney with FRP flue liner including all appurtenances - excluding foundation)	13.1	13.1	Included in 1	
4	WWT Island (design, fabricate, procure, test, package, ship, store and handle, erection, and commission, and performance testing of a nominal 50 gpm FGD Wastewater Treatment System) (turnkey EPC Island includes all structures and equipment required for a complete functioning FGD System including process/mechanical systems, instrumentation and control systems, electrical systems, and structural systems - including foundations)	15.0	11.0	Included in 1	1.) No specific mercury guarantee required with S&L. Guarantee required in URS estimate., 2.) Market pressure for scrubber WWT facilities due to CAIR., 3.) URS includes increased redundancy - two complete trains.
5	Materials Handling Island (design, fabricate, procure, test, package, ship, store and handle, erection, and commission of the limestone and gypsum handling systems) (turnkey EPC Island includes all structures and equipment required for a complete functioning limestone and gypsum handling systems including process/mechanical systems, instrumentation and control systems, electrical systems, and structural systems - excluding foundations)	44.8	21.8	Included in 1	1.) S&L assumed a 14,000 sq. ft gypsum storage building. Actual building is 26,600 sq. ft., 2.) S&L assumed hooded conveyors while URS basis was totally enclosed conveyor galleries., 3.) S&L basis for RR car unloader was bottom dump while URS basis was rotary dump., 4.) URS basis for silo discharge was rotary plow dischargers due to winter conditions while S&L basis was basic hopper arrangement., 5.) URS included an limestone emergency silo fill bucket elevator and receiving hopper while S&L did not.
6	URS Engineered Equipment (guard house, booster fans & motors, duct isolation dampers, duct expansion joints, quench pumps, service water pumps, ductwork steel fab/deliver, ductwork support steel & misc. structural steel fab/deliver, duct insulation fab/deliver, truck wash, truck scale, SW pipe intake screen, hoists, DCS, CEMS, , MV Switchgear, LV unit substation, 480V MCC's, cable bus, UPS/battery system, misc. instruments and electrical panels)	28.1	9.5	Included in 1	1.) S&L assumed single duct from MK-1 and MK-2 (385 tons including support steel), URS designed separate ducts (1935 tons). Include associated insulation, dampers, and expansion joints. S&L assumed common support structure for material handing conveyors and flue gas duct. 2.) New guardhouse, truck scale, and truck wash equipment not included in S&L scope.
7	URS Balance of Plant (site surveying; soil borings; site preparation and pre-construction relocations; cast in place concrete foundations; caisson foundations; coatings and painting; ductwork, insulation; and support steel installation; miscellaneous steel installation; BOP mechanical installation; BOP electrical installation; construction power installation; final site paving and restoration; ductwork modeling; FRP consultant; Oversight QA/QC testing)	61.0	38.3	Included in 1	1.) Installation delta for ductwork, structural steel, and associated equipment included in item 6., 2.) S&L assumed service water and quench water pumps could be installed in existing pumphouse. New service water pump house was required., 3.) S&L assumed no infrastructure improvements were included. New laydown area, plant entrance modifications,and new 700 car parking area had to be constructed. 4.) Installation of guardhouse, truck scale, and truck wash building and equipment not included in S&L scope.

8	URS Escalation	23.0	0.0	45.0	
9	URS Growth and Contingency	19.1	11.6	Included in 8	
10	Electrical power Supply	14.9	8.3	Included in 1	Refer to Response 7.
11	New Yellow Building	1.5	0.0	0.0	Not in S&L scope.
12	E-Warehouse	1.0	0.0	0.0	Not in S&L scope.
13	NU Labor	5.7	35.2	18.0	
14	NU Costs (Outside Services, Employee Expenses, Vehicles, Fees & Payments, Rents & Leases)	16.4	Included in 13	Included in 13	Insurance (12.7), Outside Consultants (2.5) Not in S&L
15	NU Costs (Miscellaneous)	4.1	Included in 13	Included in 13	Lab Equipment, Trailers, Limestone & Gypsum for Testing, Permitting, Demo & Relocations, Site Security, Construction Power Substation, Air Modeling, Final Clean Up
17	NU Indirect Costs	5.5	Included in 13	Included in 13	
18	AFUDC	56.5	Included in 13	12.0	
18	Contingency	10.0	10.0	30.0	
	TOTAL	457.0	250.0	250.0	

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-005

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-005, Appendix F. This is the first indication that there was an increase in the Sargent Lundy estimate. Is this update from 2005 to 2006 a reflection of inflation? If so, are there any other increases that are built into these costs other than just inflation?

Response:
See TS-02, Q-TECH-004, regarding the total project cost estimate, which confirms there was no change to the total project cost estimate from 2005 to 2006. Appendix F finalized the Phase II effort which used the 2006 conceptual cost cost estimate (Appendix E) and adjusted the escalation from 2% to 5%. These estimates all were based on conceptual designs and associated estimates. The conceptual work in 2005 and 2006 was being superseded by the Program Manager work which began in September 2007 and resulted in a new cost estimate in June 2008 based on actual site conditions, indicative bids received , etc.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-006

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference Staff-02, Q-STAFF-002, page 5 of 50, specifically where the presentation begins. When was this presentation prepared and by whom? Who was present for the presentation? Were Mr. Bersak, Mr. Hall and Mr. Smagula present, also? What responsibilities did Mr. Vancho have with regards to the presentation and analysis? Please provide all copies of the financial sensitivies, financial scenarios and key financial takeaways that are referenced in the presentation, if not already provided.

Response:
This presentation was prepared within a couple of weeks prior to the RaCC presentation on June 25, 2008. A number of departments and individuals contributed based on the variety of topics included. In attendance for the presentation were Mr. Long, Mr. MacDonald, Mr..Vancho, and Mr. Smagula. Mr. Vancho prepared the financial analysis and was in attendance to discuss the financial information presented. The financial information referenced in the presentation has previously been provided.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-007
Page 1 of 1

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference Staff-02, Q-STAFF-002 page 18 of 50, Has PSNH provided all parties the actual Brattle Group analysis? Please provide the document that is referred to in the presentation. Presumably there was an earlier analysis as the one referred to in the response is dated later.

Response:
Yes, PSNH previously provided the analysis. See TS-01, Q-TECH-008.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-008

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference Staff-02, Q-STAFF-002, Page 29 of 50. What title did Cameron Bready hold as an employee of NU, what role did he play in the presentation and preparation of it?

Response:
According to his May 2008 officer profile, Cameron M. Bready was Vice President – Finance for the Northeast Utilities system (NU). Mr. Bready was responsible for corporate finance, financial forecasting and budgeting, financial planning and analysis and financial policy for the company. Mr. Bready assisted in the presentation to the NU Board of Trustees on July 14, 2008 discussing the financial analysis completed.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-009
Page 1 of 1

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference Staff-02, Q-STAFF-002. Please provide the minutes to July 15, 2008 meeting of NU Board of Trustees.

Response:
See TS-01, Q-TECH-003.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-010
Page 1 of 1

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference Staff-02, Q-STAFF-002, Page 50 of 50. Why was there a 2 month delay in Mr. Shivery signing off on the approval of capital funding for PSNH's Clean Air Project? Were there any intervening meetings, exchange of information, or discussions between July 15 and September 24, 2008?

Response:
PSNH has no knowledge of any meetings, exchange of information, or discussions other than the RaCC recommendation on June 25, 2008, the Board of Trustee meeting on July 15, 2008 and Mr. Shivery's approval signed on September 24, 2008. The delay between the date of the RaCC meeting and Mr. Shivery's approval was caused by a combination of Board meetings, vacation, and other administrative duties.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-011

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TC-04, Q-TC-024. Who was present from PSNH to make that presentation to NHPUC Staff and OCA on July 30, 2008?

Response:
Attendees from PSNH included John MacDonald, Terrance Large, Stephen Hall, and Elizabeth Tillotson.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-012
Page 1 of 1

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TC-04, Q-TC-024, page 7 of 19. Please provide the Brattle Group analysis, if not already provided.

Response:
See TS-01, Q-TECH-008

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-013

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference Staff-01, Q-STAFF 012, Page 27 of 28. Is this one page the only document provided to the Legislative Oversight Committee on June 18, 2008? Who made the presentation?

Response:
Yes, this one page outlined the variety of items discussed during the presentation. Elizabeth Tillotson and Donna Gamache provided the update.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-014
Page 1 of 1

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference Staff-01, Q-STAFF- 012, page 28 of 28. Is this one page the only document provided to the Legislative Oversight Committee on June 26, 2007? Who made the presentation?

Response:
Yes, page 28 of 28 is a one page outline of the variety of items discussed during the presentation provided on June 26, 2007. Elizabeth Tillotson and Donna Gamache provided the update.

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-002, page 2 of 80. For the presentation on April 18, 2007, who was present and who made the presentation? Does PSNH have the economic analysis (Page 7) and any other analysis referred to in the presentation? Are there minutes to the meeting?

Response:
This April 18, 2007 RaCC presentation was presented by John MacDonald and Bill Smagula to provide a conceptual project review.
The analyses referenced have previously been provided and the meeting minutes are attached.
Redactions relate to items other than the Scrubber project.

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, April 18, 2007)

A meeting of the Northeast Utilities Risk and Capital Committee (RaCC or the Committee) was held at the offices of Northeast Utilities Service Company (NUSCO), Selden Street, Berlin, Connecticut, on Wednesday, April 18, 2007, at 10:30 a.m., pursuant to notice duly given.

Committee members present were Messrs. David R. McHale (Committee Chair), Gregory B. Butler, Leon J. Olivier and William J. Quinlan and Mmes. Cheryl W. Grisé and Jean M. LaVecchia, being more than a quorum of the Committee. Committee member Mrs. Kerry J. Kuhlman was absent. Also present were Messrs. Charles W. Shivery (ex-officio member), Jeffrey R. Cahoon, Carl J. Frattini, Jeffrey C. Miller, William O'Hara and Randy A. Shoop and Mmes. O. Kay Comendul, Shirley M. Payne, Lisa J. Thibdaue and Susan B. Weber. Messrs. Michael F. Ahern, Raymond M. Litwin, John M. MacDonald, Allen L. Pollock and William H. Smagula joined the meeting as noted below.

Mr. McHale, Committee Chair, presided, and Mrs. Comendul recorded.

REDACTED

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, April 18, 2007)

REDACTED

MERRIMACK STATION WET FLUE GAS DESULPHURIZATION (SCRUBBER) SYSTEM CONCEPTUAL PROJECT REVIEW

Messrs. MacDonald and Smagula joined the meeting at this point.

Mr. MacDonald distributed the presentation entitled "PSNH Clean Air Project, Wet Flue Gas Desuphurization (Scrubber) System", which will be filed with the records of the meeting. He then noted that the investment objectives for Public Service Company of New Hampshire's (PSNH) Merrimack Station Wet Scrubber Project (Project) are to (1) operate and invest in our regulated generation assets to provide economical energy service to our customers and a fair and reasonable return to our shareholders; (2) fulfill our obligations in environmental excellence; and (3) be a leader in good corporate citizenship and stewardship. He reviewed the history of Merrimack Station, which includes two coal-fired units that employ cyclone boiler technology, and the implications of the New Hampshire Clean Power Act (NHCPA) that was effective in July 2002. He noted that the NHCPA sets forth deeper reductions than mandated by Federal law/regulations for SO_2, NOx and CO_2 and uses cap and trade compliance principles. Mercury reductions were not specified; but a timetable was established for when requirements relating to timing and amount of reductions would be effective. New Hampshire House Bill 1673 (HB 1673) is the mercury reduction next-step envisioned by the original NHCPA. The bill specifies the installation of scrubber technology at Merrimack Units 1 and 2 no later than July 1, 2013, and stipulates that PSNH must achieve no less than a removal of total mercury resulting in 80% capture of the total amount of mercury contained in the coal burned at all of PSNH's coal-fired units, which includes Schiller Station. Mr. Butler left the meeting at this point.

Next Mr. MacDonald reviewed the industry background and current activity relating to scrubber technology and the strategic rationale for using this technology. He stated that the wet scrubber technology will remove the mercury required by HB 1673, and that there is no other technology that will guarantee removal of 80% of the mercury emissions of PSNH's coal fleet. Project cost was estimated in 2006 at $250 million by Sargent & Lundy, but escalating prices since that time are expected to increase the cost. Final cost projections will be known in late 2007 when firm bids are received for major components. He reviewed the currently estimated impact of the installation of the scrubber on Merrimack Station's busbar costs. Mr. MacDonald then reviewed the Project's activity and schedule.

Mr. MacDonald discussed the preliminary risk and financial assessments for the Project, Project organization and next steps. It was noted that over $1 million has been spent on the Project to date. A discussion ensued during and after Mr. MacDonald's presentation during which Mr. Shivery asked for additional information on whether it would be advisable to accelerate the schedule to qualify for incentives.

NEXT MEETING DATE

Mr. McHale stated that the next regular meeting of the RaCC will be held on May 30.

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, April 18, 2007)

There being no further business, the meeting adjourned at 12:35 p.m.

D. Kay Comendul

D. Kay Comendul

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-016

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-002 page 19 of 80: Were the indications of the revised estimates communicated at that time or at any time in 2007, to the Legislative Oversight Committee, NHPUC or anyone else outside of PSNH, including the Securities and Exchange Commission?

Response:
At the time of the April 18, 2007 RaCC presentation there was no revised project cost estimate. This presentation was a Conceptual Project Review, which would lead to the hiring of a Program Manager who would undertake the effort of developing an updated project cost estimate. The Program Manager was hired in late September 2007 and no updated project cost estimates were available in 2007. The comment on the slide is consistent and indicative of conceptual cost estimates which can vary 25- 35%.

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-002, page 40 of 80. For the presentation on May 30, 2007, who was present and who made the presentation? Does PSNH have any economic analysis and any other analysis referred to in the presentation? Are there minutes to the meeting?

Response:
This May 30, 2007 RaCC presentation was provided as discussed in the attached minutes to request initial capital funding for the hire of the Program Manager and to perform permitting activities.
The analyses referenced are the same as requested in TS02, Q-TECH-015 and have previously been provided. Redactions relate to items other than the Scrubber project.

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, May 30, 2007)

A meeting of the Northeast Utilities Risk and Capital Committee (RaCC or the Committee) was held at the offices of Northeast Utilities Service Company (NUSCO), Selden Street, Berlin, Connecticut, on Wednesday, May 30, 2007, at 9:45 a.m., pursuant to notice duly given.

Committee members present were Messrs. David R. McHale (Committee Chair), Gregory B. Butler, Leon J. Olivier and William J. Quinlan and Mmes. Cheryl W. Grisé, Kerry J. Kuhlman and Jean M. LaVecchia, being the entire Committee. Also present were Messrs. Charles W. Shivery (ex-officio member), Kenneth B. Bowes, Jeffrey R. Cahoon, James M. Clark, David S. Early, Jeffrey C. Miller, James A. Muntz, William O'Hara, Ronald S. Smith and Randy A. Shoop and Mmes. O. Kay Comendul, Lisa J. Thibdaue and Susan B. Weber. Messrs. Kevin T. Charette, Carl J. Frattini, Domenic M. Gugliotti, Terrance J. Large, Gary A. Long, Allen L. Pollock, Paul E. Ramsey and William H. Smagula joined the meeting as noted below.

Mr. McHale, Committee Chair, presided, and Mrs. Comendul recorded.

REDACTED

(pages 84 - 87 redacted)

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, May 30, 2007)

Messrs. Butler, Charette, Gugliotti, Pollock and Ramsey and Mrs. LaVecchia left the meeting at this point.

RECOMMEND CEO APPROVAL OF INITIAL CAPITAL FUNDING FOR THE PSNH CLEAN AIR PROJECT

Messrs. Large, Long and Smagula joined the meeting at this point.

Mr. Long directed the Committee's attention to the presentation entitled "PSNH Clean Air Project, Wet Flue Gas Desulphurization (Scrubber) System", included in the material for the meeting and filed with the records thereof. He noted that this presentation is a follow up to the presentation made during the April 18 meeting of the Committee, which has been included as an appendix to today's presentation. He then reviewed the investment objectives for the project and the obligation to remove more than 80% of the mercury from the coal burned at Public Service Company of New Hampshire's power stations. Mr. Long stated that this project is being presented to the RaCC for approval in two stages. The first stage addresses permitting, design and procurement planning and the request for funding for the first stage is being addressed in this presentation. The second stage addresses major equipment purchases and construction. This request will occur in March 2008. Mr. Smagula noted that today's proposal includes authorization to spend $5 million of capital and to commit up to $15 million of program manager related expenditures between now and June 1, 2008. Mr. Long then outlined the updates to be provided to the Committee based on key project milestones. A discussion then ensued.

After discussion, upon motion duly made and seconded, it was unanimously

WHEREAS, Public Service of New Hampshire management provided the Committee with a conceptual project proposal for the PSNH Clean Air Project (installation of a scrubber at Merrimack Station) and have requested $20 million in initial capital funding/commitment authority, inclusive of funds spent to date. This initial funding will be used to advance permitting, design and procurement planning including contractual commitments to third parties, after which time Public Service of New Hampshire management will request full funding for the project from the Committee; and

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, May 30, 2007)

WHEREAS, this Committee has reviewed said conceptual project proposal;

NOW THEREFORE, BE IT

RESOLVED, that this Committee finds the following initial capital funding as described in the material submitted to this meeting and ordered filed with the records thereof, is acceptable.

PSNH Clean Air Project	Initial Capital Funding/Commitment ($M)
Actual Spending through 3/31/2007	$ 1.1
Estimated Spending 4/1/2007- 6/1/2008	$ 3.9
Vendor Commitments through In-Service	$15.0*
Total	$20.0

*Spending contingent on letting of major equipment contracts to be proposed for approval in 2008.

RESOLVED, that this Committee recommends that the Chairman of the Board, President and Chief Executive Officer of Northeast Utilities approve the Initial Capital Funding/Commitments, inclusive of funds spent to date, for the PSNH Clean Air Project listed above, provided however that this Committee further recommends that this project be included in the monthly summary of all Committee approved capital projects, a status update on the project be submitted to the Committee no less frequently than quarterly and the Initial Capital Funding/Commitments set forth above shall not be exceeded without prior approval by the Committee.

NEXT MEETING DATE

Mr. McHale stated that the next regular meeting of the RaCC will be held on

June 20.

There being no further business, the meeting adjourned at 12:10 p.m.

O. Kay Comendul

O. Kay Comendul

Northeast Utilities
Risk and Capital Committee Meeting
May 30, 2007

RECOMMEND CEO APPROVAL OF INITIAL CAPITAL FUNDING FOR THE PSNH CLEAN AIR PROJECT

WHEREAS, Public Service of New Hampshire management provided the Committee with a conceptual project proposal for the PSNH Clean Air Project (installation of a scrubber at Merrimack Station) and have requested $20 million in initial capital funding/commitment authority, inclusive of funds spent to date. This initial funding will be used to advance permitting, design and procurement planning including contractual commitments to third parties, after which time Public Service of New Hampshire management will request full funding for the project from the Committee; and

WHEREAS, this Committee has reviewed said conceptual project proposal;

NOW THEREFORE, BE IT

RESOLVED, that this Committee finds the following initial capital funding as described in the material submitted to this meeting and ordered filed with the records thereof, is acceptable.

PSNH Clean Air Project	Initial Capital Funding/Commitment ($M)
Actual Spending through 3/31/2007	$ 1.1
Estimated Spending 4/1/2007- 6/1/2008	$ 3.9
Vendor Commitments through In-Service	$15.0*
Total	$20.0

*Spending contingent on letting of major equipment contracts to be proposed for approval in 2008.

RESOLVED, that this Committee recommends that the Chairman of the Board, President and Chief Executive Officer of Northeast Utilities approve the Initial Capital Funding/Commitments, inclusive of funds spent to date, for the PSNH Clean Air Project listed above, provided however that this Committee further recommends that this project be included in the monthly summary of all Committee approved capital projects, a status update on the project be submitted to the Committee no less frequently than quarterly and the Initial Capital Funding/Commitments set forth above shall not be exceeded without prior approval by the Committee.

CEO APPROVAL OF INITIAL CAPITAL FUNDING FOR THE PSNH CLEAN AIR PROJECT

Approved as recommended by the Risk and Capital Committee on May 30, 2007 as set forth above:

6/10/07
Date

Charles W. Shivery
Chairman of the Board, President
and Chief Executive Officer
Northeast Utilities

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-018

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-002 page 66 of 80. Were the indications of the revised estimates communicated at that time or at any time in 2007, to the Legislative Oversight Committee, NHPUC or anyone else outside of PSNH, including the Securities and Exchange Commission?

Response:
The Program Manager was hired in late September 2007 and no updated project cost estimates were available in 2007. The cost changes discussed on this slide refer to an increase in the initial incremental funding approved by the RaCC committee.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-019
Page 1 of 1

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-002 page 65 of 80. What is the definition of prudence preparation that had begun with consultants, studies and early planning as referenced in the presentation? Are there any additional consultant studies and planning documents that have not already been provided?

Response:
Prudence preparation used in the context of these presentations meant that the Project would be managed with an emphasis on good planning, technical work, construction, cost and schedule management, and all other aspects of executing the Project well.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-020

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-002 page 23 of 80. To whom was the April 25, 2008 presentation made to? Who prepared it? Are there minutes to the meeting?

Response:
This April 25, 2008 presentation was a Progress Update provided to the RaCC. A number of departments and individuals contributed based on the variety of topics included. The meeting minutes are attached. Redactions relate to items other than the Scrubber project.

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, April 25, 2008)

A meeting of the Northeast Utilities Risk and Capital Committee (RaCC or the Committee) was held at the offices of Northeast Utilities Service Company (NUSCO), Selden Street, Berlin, Connecticut, on Friday, April 25, 2008, at 1:00 p.m., pursuant to notice duly given.

Committee members present were Messrs. David R. McHale (Committee Chair), Gregory B. Butler, Peter J. Clarke, Leon J. Olivier and James B. Robb (who joined the meeting as noted below) and Mmes. Kerry J. Kuhlman and Jean M. LaVecchia, being the entire Committee. Also present were Messrs. Maurice C. Bafumi, Cameron M. Bready, Jeffrey R. Cahoon, Jeffrey C. Miller, Randy A. Shoop, Ronald S. Smith and James J. Vancho and Mmes. Mary E. Bimonte, O Kay Comendul, Denise M. Giangreco, Deborah J. Olisky, Shirley M. Payne, Lisa J. Thibdaue and Susan B. Weber. Messrs. David H. Boguslawski, John C. Case, Raymond L. Gagnon, Kenneth J. Galanto, Michael A. Hitchko, Terrance J. Large, James A. Muntz, Daniel T. O'Connor, David L. Plante and Ms. Laurie E. Aylsworth and Kathleen A. Shea joined the meeting as noted below.

Mr. McHale, Committee Chair, presided, and Mrs. Comendul recorded.

REDACTED

(pages 174 - 178 redacted)

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, April 25, 2008)

REDACTED

PSNH CLEAN AIR PROJECT UPDATE

Messrs. Hitchko, Large and Robb joined the meeting at this point. Mr. Hitchko directed the Committee's attention to the material presented to the meeting and filed with the records thereof regarding the status of PSNH Clean Air Project at Merrimack Station. He noted that a revised initial capital funding request of $35 million was approved by the Committee on September 24, 2007. He stated that project expenditures through March 2008 were $5.5 million, and estimated total project expenditures through June 2008 are $8 million. A discussion regarding the project's schedule, cost, engineering activities, risk assessment and an economic analysis then ensued. Mr. Butler left the meeting during this discussion. Messrs. Hitchko and Large left the meeting following this report.

REDACTED

180

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, April 25, 2008)

REDACTED

NEXT MEETING DATE

The next meeting is scheduled for Wednesday, May 21, 2008.

There being no further business, the meeting adjourned at 4:00 p.m.

O. Kay Comendul

O. Kay Comendul

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-021

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-002 page 16 of 80. Was there a PSNH Board of Directors Approval of the Clean Air Project in 2007? If not, why not?

Response:
Under the NU RaCC procedures in place, approvals necessary for the scrubber project were made by the Northeast Utilities Board of Trustees and not by the subsidiary PSNH Board of Directors. All references in the RaCC materials using the nomenclature "Board of Directors" actually should have referenced the "Board of Trustees."

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-022

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-002. Does the reference on page 15 of the April 18, 2007 presentation refer to NU Board of trustees or the PSNH board of directors?

Response:
See TS-02, Q-TECH-021.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-023

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH- 002, page 18 of 80. For the presentation on April 18, 2007, was there any information to justify or explain the statement "Prudence preparation has begun with consultants, studies and early planning" in the presentation?

Response:
Prudence preparation used in the context of these presentations meant that the Project would be managed with an emphasis on good planning, technical work, construction, cost and schedule management, and all other aspects of executing the Project well.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-024

Witness: William H. Smagula
Request from: TransCanada

Question:.
Reference TS-01, Q-TECH-002, page 70 of 80. For the presentation on September 24, 2007, who was present and who made the presentation? Does PSNH have any economic analysis and any other analysis referred to in the presentation? Are there minutes to the meeting?

Response:
This September 24, 2007 RaCC presentation was presented as discussed in the attached minutes to obtain approval for an additional incremental financial commitment associated with the Program Manager. Redactions relate to items other than the Scrubber project. The analyses discussed in this presentation are bid analyses completed by the Program Manager of the bid proposals received in response to the procurement specifications.

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, September 24, 2007)

A meeting of the Northeast Utilities Risk and Capital Committee (RaCC or the Committee) was held at the offices of Northeast Utilities Service Company (NUSCO), Selden Street, Berlin, Connecticut, on Monday, September 24, 2007, at 9:10 a.m., pursuant to notice duly given.

Committee members present were Messrs. David R. McHale (Committee Chair), Richard J. Cohen (by telephone) and Leon J. Olivier and Mmes. Kerry J. Kuhlman and Jean M. LaVecchia. Also present were Messrs. Charles W. Shivery (ex-officio member), Jeffrey R. Cahoon, Kevin T. Charette, Carl J. Frattini, Dominic Gugliotti, Jeffrey C. Miller, Allen L. Pollock, Paul E. Ramsey, Ronald S. Smith and Randy A. Shoop and Mmes. Mary E. Bimonte, O. Kay Comendul, Denise M. Giangreco, Lisa J. Thibdaue and Susan B. Weber. Committee member Gregory B. Butler and Messrs. Michael A. Hitchko, John M. MacDonald, William O'Hara, William H. Smagula and Mark A. Smith and Mrs. Laurie E. Aylsworth joined the meeting as noted below.

Mr. McHale, Committee Chair, presided, and Mrs. Comendul recorded.

REDACTED

(pages 106 - 109 redacted)

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, September 24, 2007)

REDACTED

RECOMMEND CEO AND CHAIRMAN APPROVAL OF REVISED INITIAL CAPITAL FUNDING FOR THE PSNH CLEAN AIR PROJECT

Messrs. Hitchko, MacDonald and Smagula joined the meeting at this point.

Mr. MacDonald introduced Mr. Hitchko to the Committee. He then directed the Committee's attention to the material presented to the meeting and filed with the records thereof concerning a request to increase the funding for the PSNH Clean Air Project from $5 million in initial funding and $15 million of commitment authority to $10 million in initial funding and up to $35 million of commitment authority. He stated that this revised estimate is based on the outcome of the bidding process for the Program Manager, and then described the additional scope and responsibilities of the Program Manager. Next he reviewed the profile and experience of Washington Group International, the Program Manager chosen as a result of the bidding process. A discussion then ensued.

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, September 24, 2007)

After discussion, and upon motion made and seconded, the following preamble and resolutions were unanimously adopted:

WHEREAS, following a recommendation by Public Service Company of New Hampshire management on May 30, 2007, this Committee reviewed a conceptual project proposal for the PSNH Clean Air Project (installation of a scrubber at Merrimack Station) (the Project) including a request for $5/$15 million in initial capital funding/commitment authority, inclusive of funds spent to date. This initial funding/commitment authority was to be used to advance permitting, design and procurement planning, for the Project, including contractual commitments to third parties, after which time Public Service of New Hampshire management will request full funding for the Project from the Committee; and

WHEREAS, this Committee recommended that the Chairman of the Board, President and Chief Executive Officer of Northeast Utilities (CEO) approve the requested initial capital funding/commitment authority for the Project; and

WHEREAS, the CEO subsequently approved the initial capital funding/commitment authority for the Project; and

WHEREAS, Public Service Company of New Hampshire management has proposed that this Committee review a proposal to increase the amount of initial funding and commitment authority for this Project to $10/$45 million, inclusive of funds spent to date based on the results from the solicitation for a Program Manager for the Project; and

WHEREAS, this Committee has reviewed said proposal;

NOW THEREFORE, BE IT

RESOLVED, that this Committee finds the following revised initial capital funding as described in the material submitted to this meeting and ordered filed with the records thereof, is acceptable.

PSNH Clean Air Project	Revised Initial Capital Funding/Commitment ($M)
Initial Funding through 6/1/2008	$10.0
Vendor Commitments through In-Service	$35.0*

*Spending contingent on letting of major equipment contracts to be proposed for approval in 2008.

NORTHEAST UTILITIES
RISK AND CAPITAL COMMITTEE
(Committee Meeting, September 24, 2007)

RESOLVED, that this Committee recommends that the CEO of Northeast Utilities and the Chairman of Public Service Company of New Hampshire (Chairman) approve the revised Initial Capital Funding/Commitments, inclusive of funds spent to date, for the PSNH Clean Air Project listed above, provided however that this Committee further recommends that this project be included in the monthly summary of all Committee approved capital projects, a status update on the project be submitted to the Committee no less frequently than quarterly and the revised Initial Capital Funding/Commitments set forth above shall not be exceeded without prior approval by the Committee.

NEXT MEETING DATE

The next meeting is scheduled for October 17, 2007.

There being no further business, the meeting adjourned at 11:10 a.m.

O. Kay Comendul

O. Kay Comendul

Northeast Utilities
Risk and Capital Committee Meeting
September 24, 2007

RECOMMEND CEO AND CHAIRMAN APPROVAL OF REVISED INITIAL CAPITAL FUNDING FOR THE PSNH CLEAN AIR PROJECT

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CEO AND CHAIRMAN APPROVAL OF REVISED INITIAL CAPITAL FUNDING FOR THE PSNH CLEAN AIR PROJECT

Approved as recommended by the Risk and Capital Committee on September 24, 2007 as set forth above:

10/3/07
Date

Charles W. Shivery
Chairman of the Board, President and
Chief Executive Officer
Northeast Utilities
Chairman of the Board of
Public Service Company of New Hampshire

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-025

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-002, page 75 of 80. In reference to the September 24, 2007, what was the estimate of how much the project management would exceed the original $250m? Were there any other anticipated increases at that time?

Response:
The referenced presentation discussed the estimated cost of the Program Manager. This Program Manager cost was only one item of many to determine the total project costs, yet to be known. There was no new or revised project estimate at this time. It should also be noted that the change in Program Manager cost estimate was not equal to or necessarily indicative of a change in total project cost. This change in scope for the Program Manager would result in a more efficiently managed project, better align work with skills and resources, and help in reducing overall cost.

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference TS-01, Q-TECH-002 page 75 of 80. Were the indications of the revised estimates communicated at that time or at any time in 2007, to the Legislative Oversight Committee, NHPUC or anyone else outside of PSNH, including the Securities and Exchange Commission?

Response:
On September 24, 2007, as shown on page 75 of 80, updated information was provided to the Risk and Capital Committee (RaCC) regarding the Project Manager cost estimates. Defining the specification and sending the request for bids for the Project Manager role was one of the early commitments necessary in the project timeline. As part of the approval process, RaCC had approved in May moving forward with this important first step and the associated estimate of $15M. The September presentation discussed changes to that estimate and confirmed the new estimate was $35M for the reasons noted below.

* Original Sargent & Lundy estimate of $15 Million based on less Project Manager responsibility and shorter Project Schedule.

* Bidding Specifications and Bid analysis by the project team has put more scope and responsibility on the Program Manager. Current estimate is $35 Million.

These Project Manager dollars are just one item of many yet to be known costs determining the total estimated project cost. There was no new or revised project estimate at this point and thus no specific notifications. It can be noted that the change in Project Manager cost estimate was not equal to or necessarily indicative of a change in total project cost, which would be defined well after the selection and hiring of the Project Manager.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-027
Page 1 of 1

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

Question:
Reference TC-01, Q-TC-020, Staff-01, Q-STAFF-010, and OCA-01, Q-OCA-004. What is the current status of the baseline mercury emissions?

Response:
The initial baseline mercury emissions determination established by NHDES remains preliminary. The next step is a final determination by the NHDES Air Resources Department.

Witness: William H. Smagula
Request from: TransCanada

Question:
In DE 08-103, in the letter dated September 2, 2008, page 15 in section D. What is the heat rate factor used to calculate the forward market price in electricity? Where in the documents provided does it show up? If it is not in the documents provided, please provide it.

Response:
Please see TC-03, Q-TC-006 where the following was asked and answered.

TC Question:
Reference the September 2, 2008 report by PSNH to the Commission in DE 08-103, page 15, Section IV.D, please provide the heat rate factor that PSNH applied and provide any and all documentation in PSNH 's possession or the possession of any of its agents related to the analysis described in this section. Please explain when and why this analysis was done.

PSNH Response:
The heat rate factor applied was 7.62 MMBtu/MWH. This is a 2008-2011 average implied heat rate calculated from NYMEX gas prices. The attached exhibit provides the supporting detail for the 7.62 number. This analysis was done in the summer of 2008 to support the update filing to the NHPUC.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-029
Page 1 of 1

Witness: Terrance J. Large
Request from: TransCanada

Question:

Reference TC-03, Q-TC-003. When were these spreadsheets prepared? Looking at page 3 of 3, row 6, it appears that the depreciated life was projected to be about 15 years. The current depreciated life of Merrimack Station goes through 2038, rather than 2027. Please explain why in the initial phases of the project there was a 15 year depreciated life and why that was changed to a considerably longer life. Please clarify if 2027 refers to the plant and the scrubber or just the scrubber.

Response:

The exhibit provided in TC-03, Q-TC-003 was prepared during the July through September 2008 timeframe. As noted, during the initial phases of the scrubber analysis an estimate of 15 years was used for its depreciated life which represented a shorter life estimate among the range of reasonable life of a scrubber. The plant was being depreciated at 3.215% or approximately 32 year life. The updated depreciation aligns the plant life and the scrubber life.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-030
Page 1 of 1

Witness: Terrance J. Large
Request from: TransCanada

Question:
Reference TC-03, Q-TC-003. In the attached exhibit, cell B5 lists the 2012-2017 average impact on energy service rates. Should it read 2012-2027 average impact on energy service rates?

Response:
In the exhibit attached to the response to TC-03, Q-TC-003, the cell A5 text, "Scrubber 2012 to 2027 avg rate impact", correctly describes cell B5. The adjoining discussion should have also read 2012 -2027.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-031

Witness: Kevin P. Morrissey, Michael L. Shelnitz
Request from: Office of Consumer Advocate

Question:
Reference OCA-04, Q-OCA-017, d. In reference to the retirement year of 2038, is the life of the scrubber 25 years for ratemaking purposes? What is the tax depreciable life? Please give a year-by-year calculation of deferred taxes.

Response:
Pursuant to Rule Puc 203.08(d), PSNH has a good faith basis for seeking confidential treatment of the information contained in this response and would submit a motion for confidential treatment regarding such documents at or before the commencement of the hearing in the event that a party wishes to include this information in the record of the proceeding.

In reference to the retirement year of 2038, the scrubber life is 25 years for ratemaking purposes. The tax depreciable life is as follows:

	Scrubber Tax Basis
Pollution Control Sec 169 - 50% Bonus / 5 YR SL (2011 vintage)	$275,385,489
50% Bonus MACRS20 (2011 & 2012 vintages)	106,118,258
100% Bonus - (2012 vintage)	25,537,678
Total Tax Basis	$407,041,425

Note: The state tax depreciable life for the Sec 169 Pollution Control property is 5 YR SL and MACRS20 for the remaining property.

See attached schedule for the year-by-year calculation of deferred taxes.

This information is considered "Protected Material" and is available only to signatories of the nondisclosure agreement.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-032
Page 1 of 1

Witness: William H. Smagula, Timothy J. Griffin
Request from: Office of Consumer Advocate

Question:
Reference OCA-04, Q-OCA-017; d. Has PSNH used the same depreciated life since the scrubber was declared in service or has there been a change? What is being used currently and what was used if there was a change?

Response:
The Scrubber has been using an AYFR year of 2038 since September 2011 when it was put in service.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-033

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

Question:
Reference Staff-02, Q-STAFF-005. Please provide an update to the response.

Response:
Staff-02, Q-Staff-005, asked the following:

> *Follow-up to the response to OCA Set #2, Question #15. Please provide details concerning the sales of gypsum since operation of the scrubber commenced. How much gypsum has been sold? At what price(s)? How are the trucking costs figured into the sales price (which party pays for the trucking)? What would disposal costs be if the gypsum could not be sold?*
>
> *As stated in Staff-02, Q-Staff-005, as of August 30, 2012, PSNH had sold 40,043.70 tons of gypsum. Gypsum is sold at a positive price; however, the transaction is net of trucking costs. The result of the sale of gypsum and trucking costs results in a cost of $2.00 per ton.*
> *If gypsum were not sold to a wallboard company, it would have to be disposed of by bringing it to a landfill. The current rate for disposal of solid material is $89.32 per ton. Creating this product and developing this sale contract saves customers millions of dollars per year.*

As of July 27, 2013, 99,160.77 tons of gypsum have been sold. At these volumes, the net cost of gypsum is $2.00 per ton which includes trucking costs. The contract also recognizes that production levels will vary from planned amounts. These variations result in a true-up on a 12 month basis between PSNH and GP.

Public Service Company of New Hampshire
Docket No. DE 11-250

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

Question:
Reference the Jacobs Report, pages 64-65. Related to the scrubber, how many employees have you added, and how many additional will you add?

Response:
As stated in the Jacobs Report, in preparation for operational and maintenance changes, PSNH reviewed the makeup of its station staff based on the knowledge acquired from other facilities where similar wet flue gas desulfurization systems were installed, and PSNH planned to add nine station staff: five operators or shift workers — one per shift group, one engineer/ FGD operations expert, one chemist, one instrumentation technician, and one mechanic.

However, in an effort to balance costs and current operational needs, expanding permanent staff at Merrimack Station is proceeding slowly. To date, the net change to the Station organizational structure due to the scrubber has been the addition of one engineer.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-035

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

Question:
Reference the Staff Audit Report, page 6. Please quantify the amounts for each of Phase 1 and Phase 2 of the project. Please describe what each phase is.

Response:
The reference, Staff Audit Report page 46, correctly states that Sargent & Lundy performed engineering work associated with the 2005 RSA 125:O requirement to reduce mercury (known as Phase I) and further engineering work associated with refining the recommendation for the limestone based wet FGD (known as Phase II). [Note: The statutory reference should be to the initial enactment of RSA Ch. 125-O, the Multiple Pollutant Reduction Program, in 2002 contained in 2002 N.H. Laws, Chapter 130.]

The Phase I effort took a broad look at a variety of options for Merrimack Station recognizing the Legislature's actions to reduce mercury emissions at the PSNH plants. The findings indicated installation of a wet FDG at Merrimack Station was the most cost effective means to reduce emissions as mandated by NH Clean Power Act.

After completion of Phase I, Phase II expanded upon the findings by examining preliminary design aspects of the wet FGD system including equipment specifications for principal components.

The total amount paid to Sargent & Lundy for these two engineering phases was $434,200. Phase I costs were $235,200 and Phase II costs were $199,000.

Public Service Company of New Hampshire
Docket No. DE 11-250

Technical Session TS-02
Dated: 07/24/2013
Q-TECH-036
Page 1 of 1

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

Question:
Reference TS-01, Q-TECH-011. Please provide actual use data based on the estimates.

Response:
Response provided in TS-01, Q-TECH-011 - *The truck wash facility was sent out for bid in 2009 and was awarded in early 2010. At that time, a review of coal truck traffic in 2008 and 2009 revealed about 8,500 truck deliveries per year. To move the contracted gypsum quantity, approximately 4,200 trucks per year would be needed. Based on trucking rates known for travel to/from Bow to Newington, the annual trucking cost for dedicated trucks would be over $1 Million per year. The alternative, often referred to as back hauling, would be to use coal trucks which would otherwise be returning to the seacoast empty. This was estimated to save approximately $4/ ton in trucking cost. Using the approximately 4,200 trucks each hauling about 30 tons, the savings associated with back hauling was determined to be over $500,000 per year. However, to ensure the quality of the gypsum product, the dump compartments of the coal trucks would have to be cleaned before loading gypsum. Discoloration and coal dust contamination is not acceptable to the gypsum purchaser. The final cost of the truck wash was $2,293,725. The revenue requirement in the initial years is between $350,000 and $400,000 (depending on the specific assumptions and then declining over time) which results in a lower annual customer cost compared to the $500,000 trucking cost per year. Based on these basic economics, the cost of the truck wash was an economic benefit for customers. Furthermore, this would eliminate wasteful use of fuel and unneeded vehicle emissions.*

Gypsum trucking began April 30, 2012. Coal trucking between Schiller Station and Merrimack Station has not occurred since April 13, 2012 due to the unavailability of Venezuelan coal.

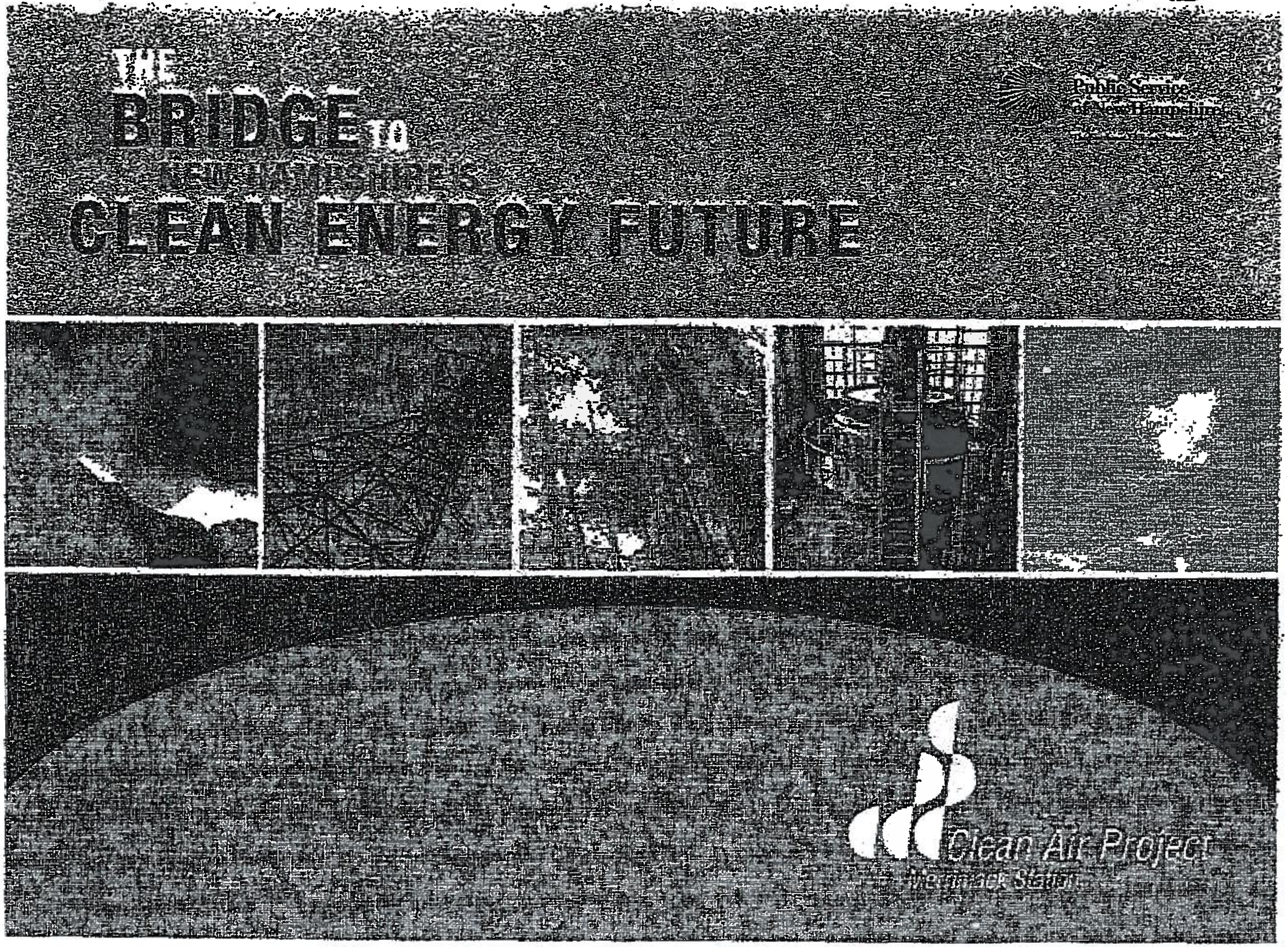
Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-03
Dated: 08/24/2012
Q-TC-014

Witness: Gary A. Long
Request from: TransCanada

Question:
Reference the attached 31 page power point from the legislative history of SB 152 from the 2009 session of the NH Legislature, who produced this document ? By whom was this person or persons employed ? Who testified before the Legislature on this power point ?

Response:
The document was produced through a collaborative effort of several people at PSNH. Gary A. Long testified before the legislature on this topic, although his testimony did not present this document in significant detail; rather, the document was provided to legislators and referred to during Mr. Long's testimony.



Data Request TC-03
Dated: 08/24/2012
Q-TC-014
Page 2 of 31

Today's Agenda

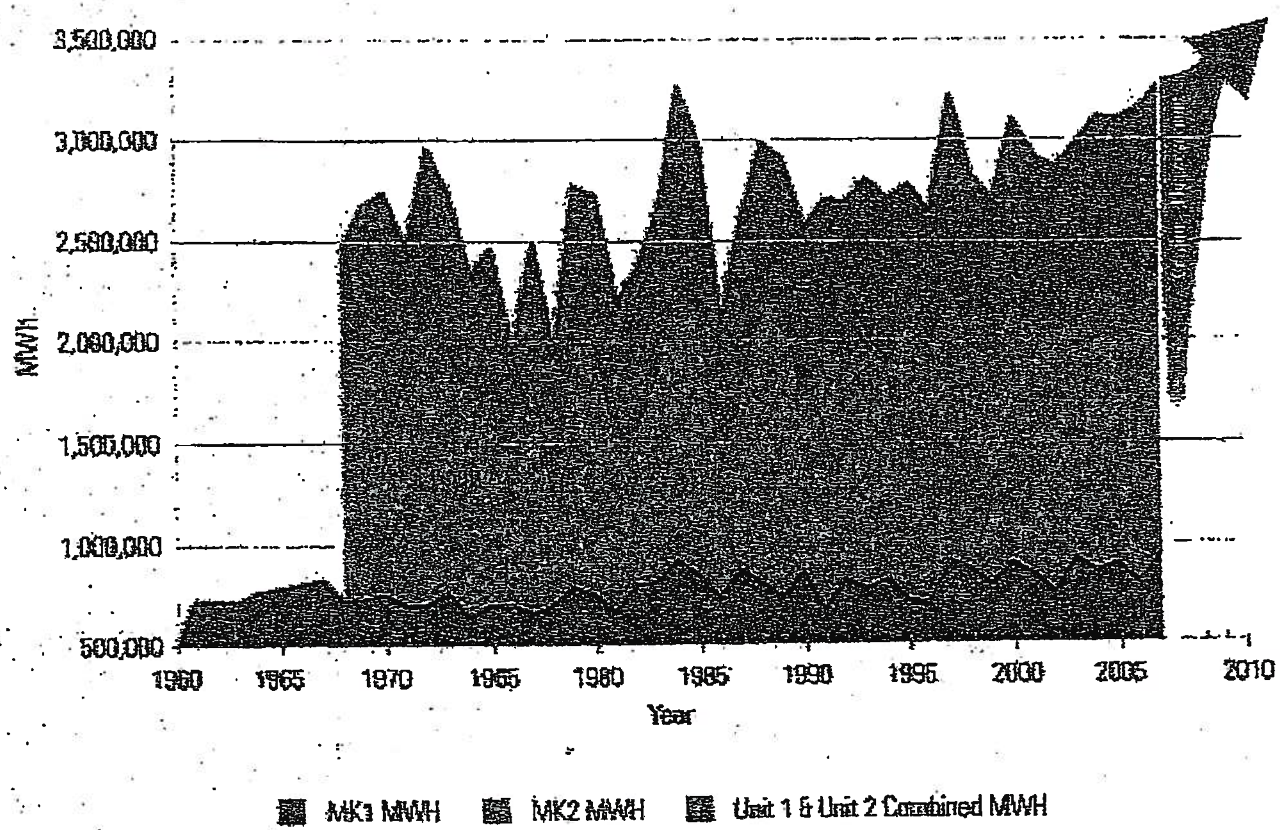
- The Clean Air Project
- Cost
- Project Benefits
- Senate Bill 152
- The Bridge to NH's Clean Energy Future

Merrimack Station in Bow

- **New Hampshire's workhorse**
  - Base load power plant that operates 24/7
  - Coal-fired
  - 433 MW net output
  - Enough energy for 190,000 NH households
    - » 35% of PSNH's generation mix
  - Meets or exceeds all environmental regulations
    - » 20 years of progress guided by state and federal clean power laws (NH Clean Power Act, RGGI, Mercury Law)

Merrimack Station is Running Better than Ever

PSNH customers have invested millions over the years to upgrade equipment and maintain Merrimack Station in top operating condition.



Data Request TC-03
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New Hampshire's Blueprint for Lowering Emissions: The 2002 Clean Power Act

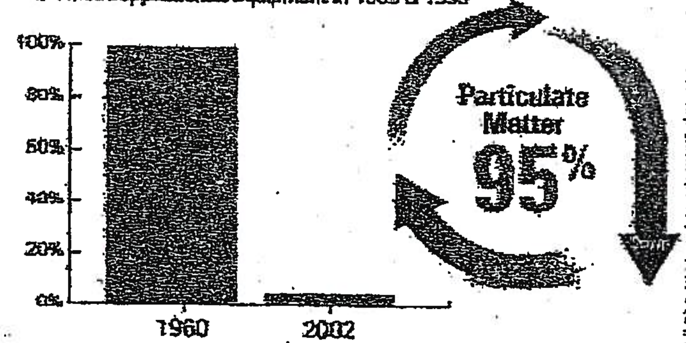
✓	NO_X	**85% Reduction – 1995/2000** Achieved through installation of groundbreaking Selective Catalytic Reduction system
✓	Mercury	**80% Reduction or Better – 2013 or sooner** Required under the Mercury law that was passed in 2006
✓	SO_X	**90% Reduction or Better – 2013 or sooner** A benefit of the Mercury law that was passed in 2006
✓	CO_2	**Stabilized emissions through 2014: 10% reduction from 2015 – 2018** RGGI legislation passed in 2008

Ground-breaking emissions reductions achieved through forward-looking legislation, careful implementation, and staying the course.

Emissions Control Technologies Installed at Merrimack Station: 20 Years of Progress

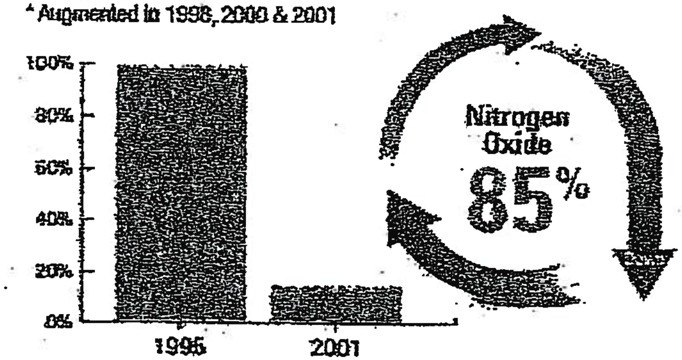
Electrostatic Precipitators

* Installed in 1960 &1968
* Installed supplemental equipment in 1989 & 1999

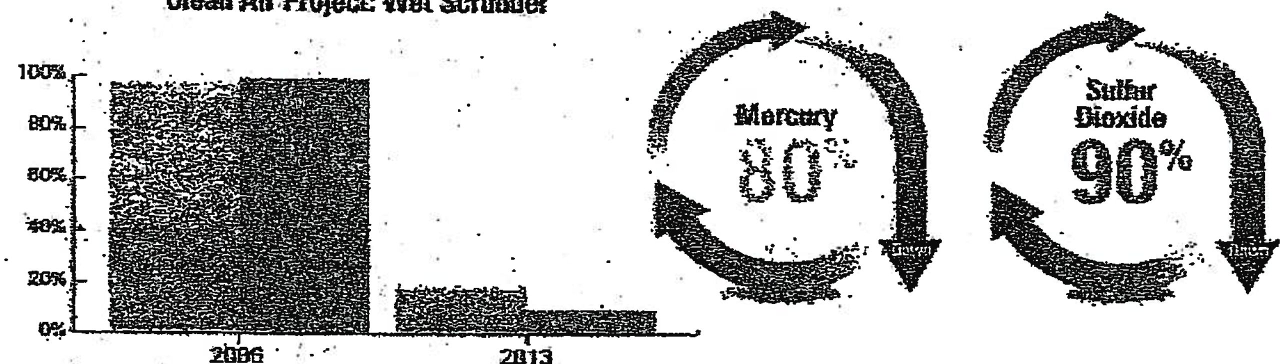


Selective Catalytic Reduction System

* Installed in 1995 & 1999
* Augmented in 1998, 2000 & 2001



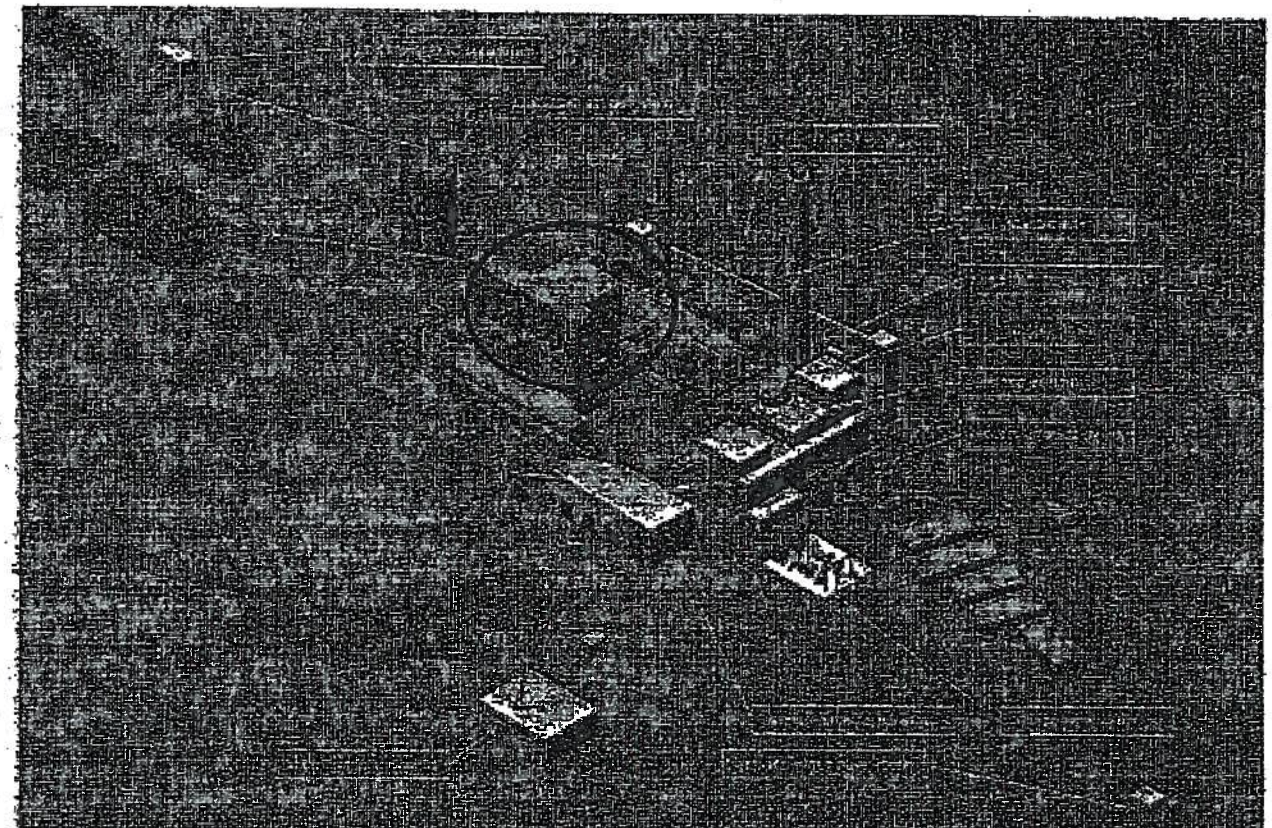
Clean Air Project: Wet Scrubber



Status of the Clean Air Project

- In a 2006 law, the NH Legislature mandated that a scrubber be installed as soon as possible, but no later than July 2013
- Even without the state law, the scrubber will be needed to meet impending federal emissions requirements
- PSNH is currently halfway through the six-year project
- $230 million (over half of the cost to engineer and build the scrubber) has been spent or contractually committed
  – This cost will have to be recovered from PSNH customers whether or not the scrubber installation is completed

Understanding the Scope of the Clean Air Project
Merrimack Station: 2012



Data Request TC-03
Dated: 08/24/2012
Q-TC-014
Page 9 of 31

Project Schedule

Project	2006	2007	2008	2009	2010	2011	2012
NH Mercury Reduction Act							
Preliminary Engineering							
Program Manager Hired							
Detailed Engineering							
Major Contracts Awarded							
Major Permitting							
Preliminary Site Prep.							
Major Construction (underway)							
Testing & Commissioning							
In Service							

Data Request TC-03
Dated: 08/24/2012
Q-TC-014
Page 10 of 31

COST

Data Request TC-03
Dated: 08/24/2012
Q-TC-014
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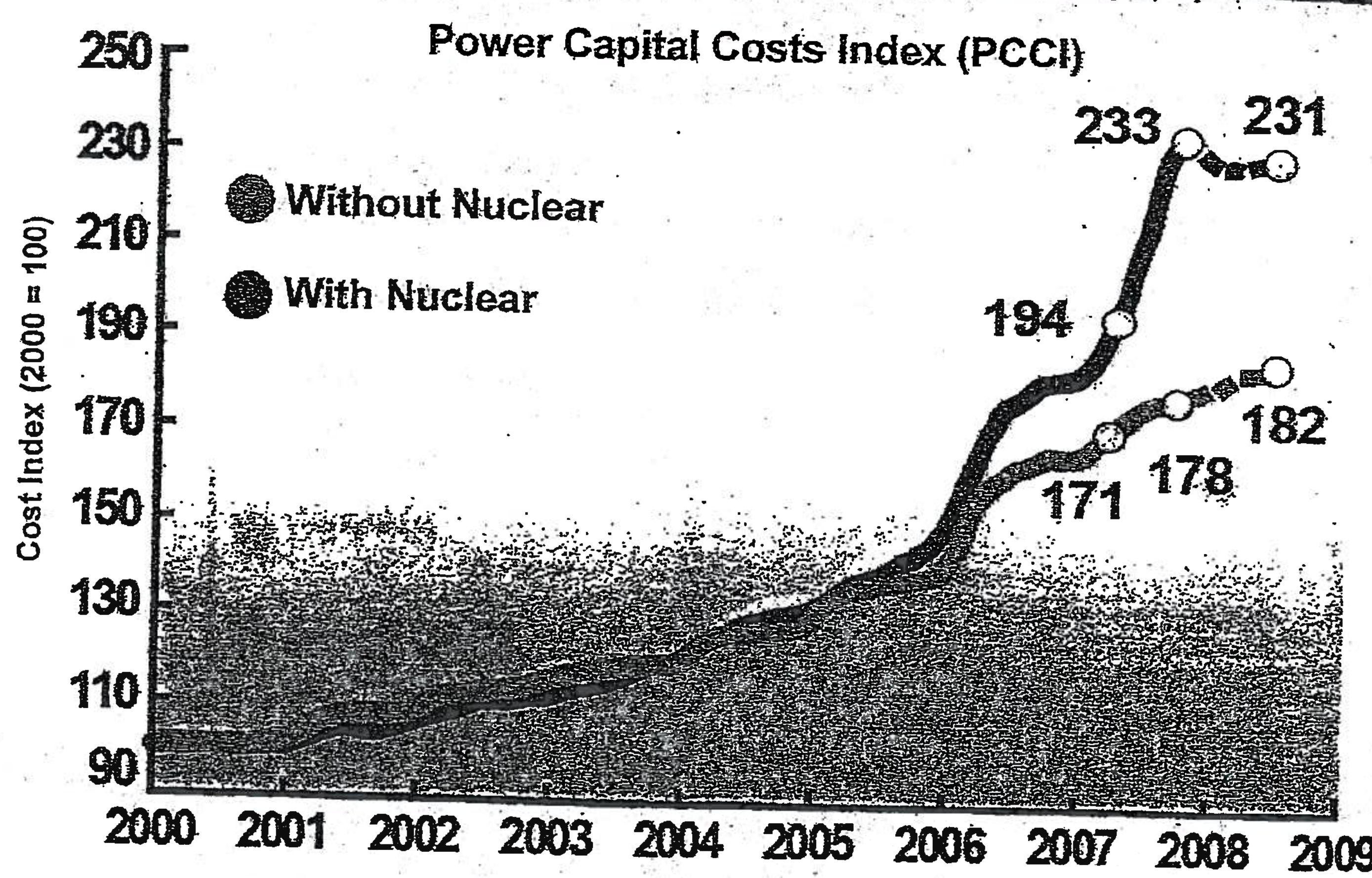
2005 / 2008 Cost Comparison

Project Components	**2008** (firm price contracts)	**2005** (initial estimates)
5 Major Contracts • Scrubber system, chimney, material handling system, wastewater treatment facility, program manager	**$213M**	$149M
Balance of Contracts and Materials • Ductwork, foundations, booster fans and motors, electrical, site work, etc.	**$135M**	$48M
Owners Costs • Project financing, insurance, NU labor, and overhead costs	**$80M**	$35M
Escalation and Contingency	**$29M**	$18M
TOTAL	**$457M**	$250M

Three Major Drivers of Cost Increase

- **Economic and Commodity Volatility**
  - Significant cost increases reflective of national and world economy
  - Increased financing costs
- **Site Specific Factors**
  - Scrubber must guarantee 85% mercury reduction
  - Two power generation units of differing size must connect into one scrubber system
- **Progression from Initial Estimate Phase to Design Phase**
  - Firm price performance-based contracts with vendor guarantees have replaced initial estimated pricing
  - Majority of project design completed, replacing preliminary engineering used to determine initial estimates

Capital Costs Increased Significantly



Source: Cambridge Energy Research Associates. 71023-12

Data Request TC-03
Dated: 08/24/2012
Q-TC-014
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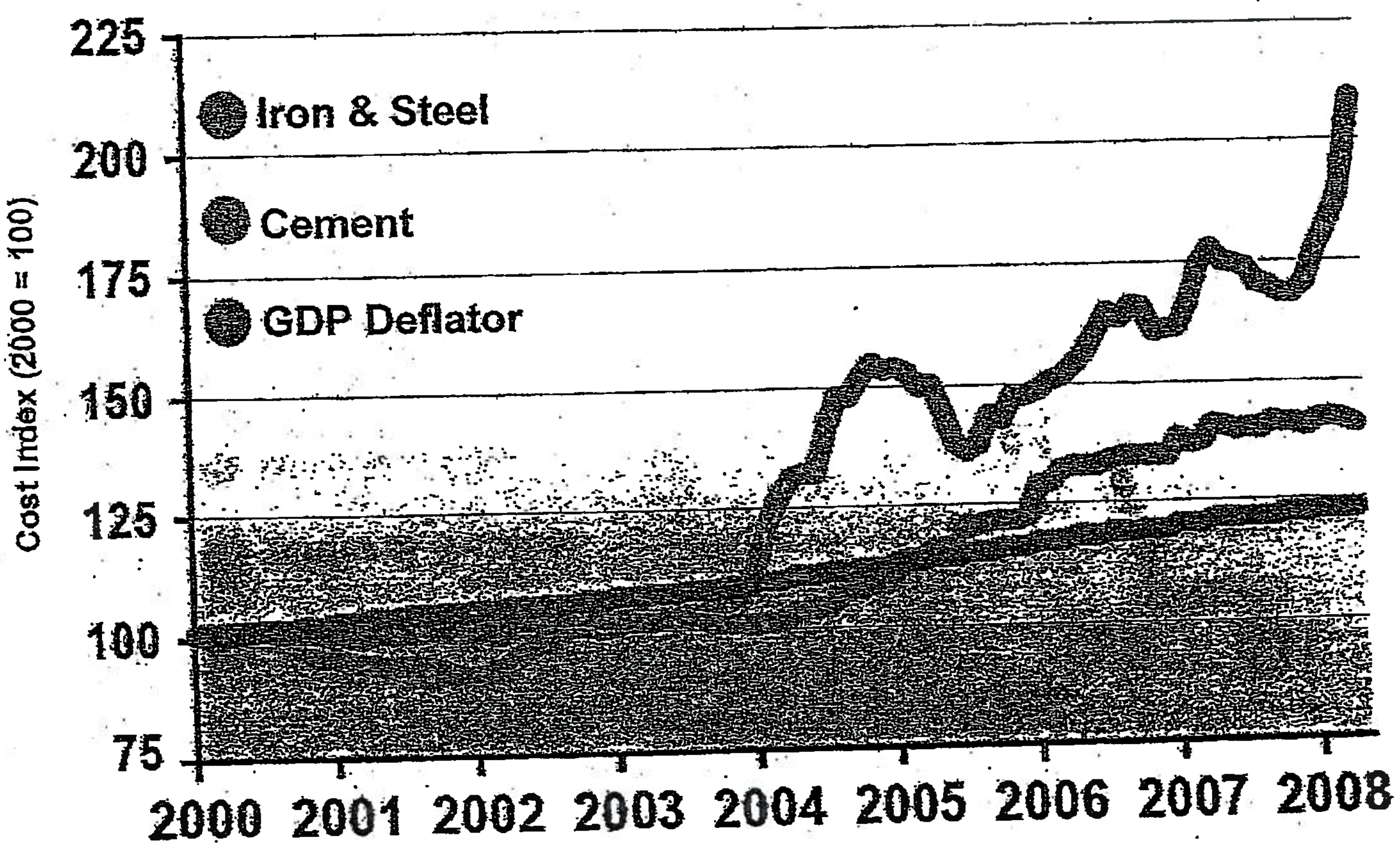
Primary Construction Costs



Source: Derived from Bureau of Labor Statistics Data and Bureau of Economic Analysis Data

16.

Data Request TC-03
Dated: 08/24/2012
Q-TC-014
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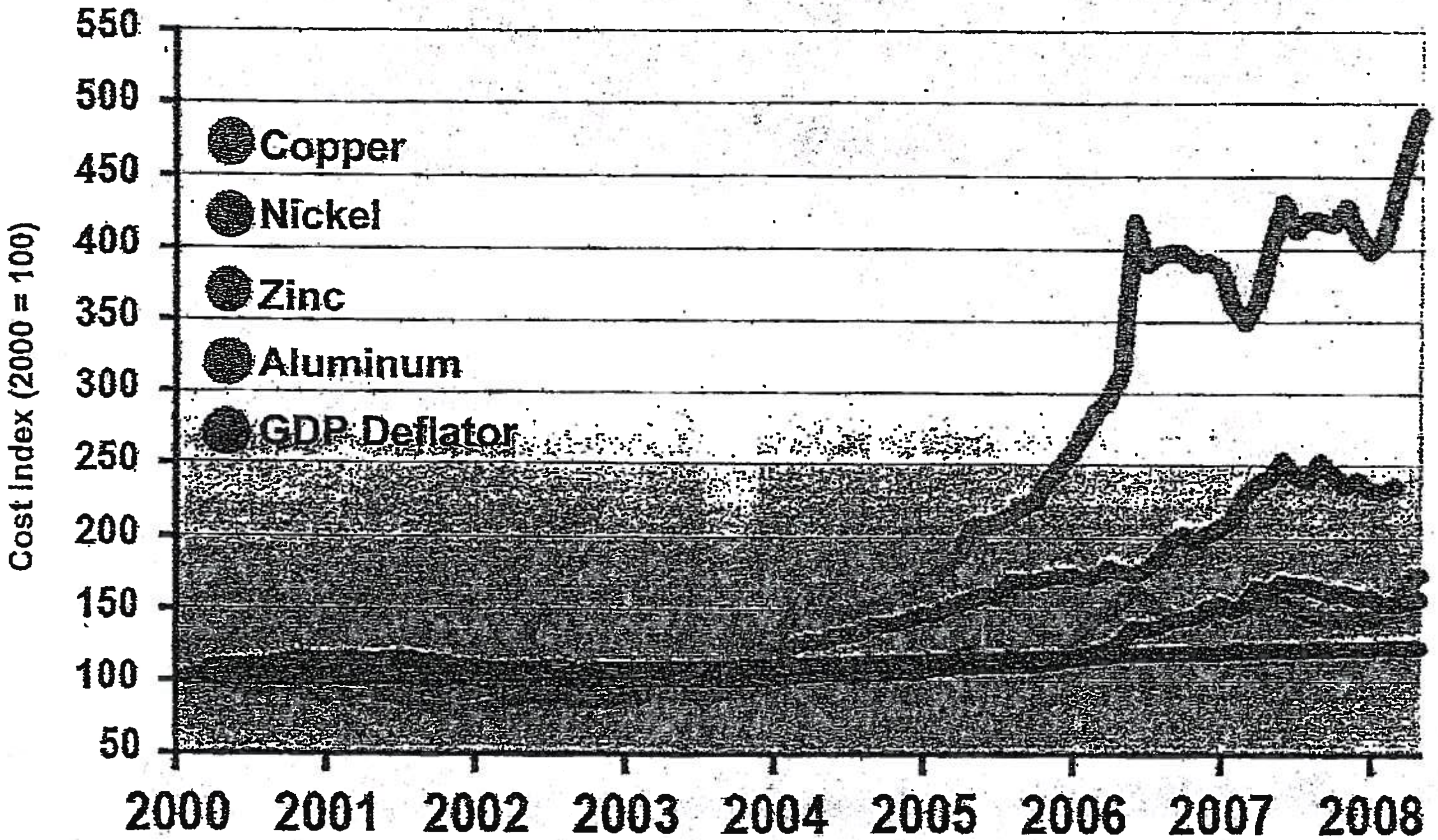
Secondary Construction Costs



Source: Derived from Bureau of Labor Statistics Data and Bureau of Economic Analysis Data

Overview of Cost Increase: From Estimate to Implementation

2005 - $250 million

- Preliminary estimate for generic scrubber
- Requirements for aggressive 85% mercury reduction and 2013 completion date were not yet established by Legislature
- Based on study performed by national engineering firm Sargent & Lundy, with additions for contingencies by PSNH
- Reflects market conditions in early 2005
- Reflects inability to forecast the highly volatile global market environment that emerged between 2005 and 2008

2008 - $457 million

- Confirmed cost for a scrubber that is required to reduce mercury emissions by 85% (one of the first in the nation)
- Includes guarantee from vendors for 85% mercury reduction
- Based on highly detailed engineering specs and firm price contracts for major components
- Reflects realities of market conditions in 2008 (including the cost of financing)
- Comparable with other multiple unit scrubber installations now occurring elsewhere in the country
  - Reaffirmed by independent firm Power Advocate, Inc. in March of 2009

PSNH's Approach Is Designed to Reduce Customer Risk

- Cost risks for major components put on vendors, not customers
  - Obtained firm price contracts for "critical path" components with long lead times
  - Developed strict performance criteria, and required performance guarantees from vendors
- At every step of the way, we have affirmed pricing to ensure it is in line with marketplace
  - Independent firms retained to provide market analysis and price benchmarking in 2005, 2006, 2007, 2008, and 2009
  - Confirmed project costs are consistent with market prices for projects of similar scope and size
- Delayed subcontracts when possible to take advantage of opportunities for better price negotiations

Customer Cost Safety Nets

- PSNH has legally binding, firm price contracts in place for major components of project
- When the project is complete, the NH Public Utilities Commission will scrutinize every dollar spent on the project before any money can be recovered from customers through PSNH's rates
- PSNH customers (esp. commercial customers) can switch to a different energy supplier at any time to avoid paying costs associated with the scrubber
- The bottom line:
  - Installation of the scrubber at $457M continues to be a better option for PSNH customers than purchasing replacement energy in the open market

Data Request TC-03
Dated: 08/24/2012
Q-TC-014
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PROJECT BENEFITS

Project Benefits

Clean Air Project

Merrimack Station

Environment

Data Request TC-03
Dated: 08/24/2012
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22.

SENATE BILL 152

Impact of Senate Bill 152

- No bill is necessary to understand the cost change outlined in earlier slides
- The only alternative to installing the scrubber is to NOT install the scrubber
  - *$457M for scrubber is not transferrable to other clean energy projects*
- Without the scrubber, Merrimack Station will be out of compliance with state and federal laws, which would lead to a shutdown of the plant
- PSNH customers could be on the hook for $300 million in stranded costs, with nothing to show for it
  - $230M for scrubber costs already committed
  - $63M for undepreciated cost of Merrimack Station in 2013

What Is the Harm in a 90-Day Study?

- What a study will **NOT** do:
  - Change the cost of the scrubber
  - Change Merrimack Station's fuel source
  - Provide accurate forecasts for the price of oil, gas, coal, or financing rates
  - Tell you what federal regulations will be passed and when
  - Tell you how much renewable energy NH will build, where it will be located, and when it will be in service
  - Accurately predict the future
- What a study **will** do:
  - Invite lengthy speculation and create momentum to not install the scrubber
  - Set Merrimack Station on the path to a shutdown

What Is the Benefit of a 90-Day Study?

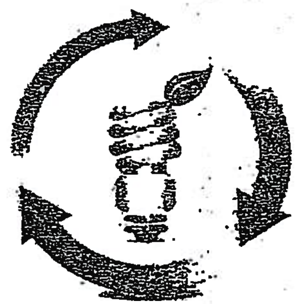
- The study cannot change the price of the scrubber
- It cannot transfer the $457M scrubber cost to other energy projects
- If the study *supports* the scrubber installation, it is redundant and not needed
- The only logical purpose for performing a study is to create momentum to derail the scrubber installation

Voting in favor of SB 152 is voting to shut down Merrimack Station.

The Bridge to NH's Clean Energy Future

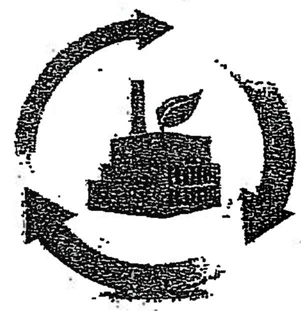
PSNH is Pursuing a Portfolio of Strategies to Advance Clean Energy in New Hampshire

Enhance and Expand Energy-Efficiency Programs



- Revise programs to meet modern needs
- Double investment in efficiency programs
- Goal of quadrupling energy savings for PSNH customers by 2025

Significantly Cut Emissions at Existing Power Plants



- Install scrubber at Merrimack Station
- Pilot alternative energy sources at PSNH facilities
- Increase efficiency at existing hydro plants

Invest in Renewable Energy Projects

- Small-scale projects (e.g. solar panels)
- Commercial-scale renewable power plants
- Import hydro power from Canada
- Provide transmission to connect customers with renewable energy sources

Conclusions

- **The Scrubber Project is NH's Bridge to a Renewable Energy Future**
- In the short-term, it is unrealistic to think that we can depend on new renewable energy sources in NH to replace the power produced by existing fossil fuel plants
- It is important to make our existing power plants cleaner and more efficient because they still provide most of our energy at the lowest cost
- Shutting down Merrimack Station would create needless economic harm to our state at a time when NH citizens are fighting every day to keep their jobs
- We implore you to vote NO to Senate Bill 152 – *Voting in favor of SB 152 is voting to shut down Merrimack Station.*

Clean Air Project

Merrimack Station

Data Request TC-03
Dated: 08/24/2012
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Merrimack Station Clean Air Project

- PowerAdvocate, Inc.
  - Premier provider of supply-chain and sourcing solutions to energy companies
  - Direct experience on over 20 different FGD projects with 9 different companies in the past 5 years
- Merrimack Station Cost Estimate
  - 19 benchmark wet FGD projects were compared to Merrimack Station
  - Owner's costs and site specific factors were analyzed to make it "apples to apples"
  - Benchmark projects were escalated to 2012 dollars (Merrimack Station's projected in-service date)
  - Merrimack per kW cost of $580 is within both the benchmark range ($272-$704/kW) and median cost ($517/kW) of the other wet FGD projects
- Project Sourcing Process and Contracting Terms
  - A procurement strategy and competitive bid process were used to ensure cost controls for customers
  - Performance guarantees and cost risks were transferred to the key suppliers to provide customer cost protection
- Cost Savings Opportunities Exist
  - Market volatility and dropping commodity prices provide near term savings opportunities
    - $6M (35%) foundation contract savings
  - Other savings opportunities exist

Data Request TC-03
Dated: 08/24/2012
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Public Service of New Hampshire

780 N. Commercial Street, Manchester, NH 03101

Public Service Company of New Hampshire
P. O. Box 330
Manchester, NH 03105-0330
(603) 634-3355
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bersara@psnh.com

The Northeast Utilities System

Robert A. Bersak
Assistant Secretary and
Assistant General Counsel

N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-14
Witness William H. Smagula
DO NOT REMOVE FROM FILE

RECEIVED NOV 02 2009 NH PUBLIC UTILITIES COMMISSION

October 30, 2009

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

Re: ***Docket No. DE 08-103, Public Service Company of New Hampshire Merrimack Station Scrubber Project – Request for Information***

PSNH Response to CLF letter dated October 23, 2009

Dear Secretary Howland:

By letter dated October 23, 2009, Conservation Law Foundation requested that the Commission order PSNH to update data provided in the Company's September 2, 2008 "Report" filed in this docket. As a basis for its request, CLF cites to the Commission's "Order on Scope" (Order No. 24,979 dated June 19, 2009, *slip op.* at 18) issued in the Company's financing docket, DE 09-033:

> In describing the scope of our review in this case as not encompassing matters related to the propriety of the scrubber installation, we note that we have an open docket, DE 08-103, in which we are monitoring PSNH's costs of construction of the scrubber technology at Merrimack Station. In that docket we will consider the prudence of PSNH's actions during the construction of the scrubber, including whether it avails itself of the variance procedure under RSA 125-0:17 in the event of escalating costs.

PSNH is pleased to report that construction of the scrubber mandated by RSA 125-O:11, *et seq.*, is proceeding on-time and on-budget. At this point in time, the costs of construction of the scrubber technology at Merrimack Station are not escalating. As there are contracts in place for nearly all aspects of the project, PSNH does not deem any future price escalation likely.

The Company is confident that it will comply with the statutory in-service date for this emissions control system of July 1, 2013. RSA 125-O:13, I. Barring any unforeseen construction delays, PSNH anticipates having the scrubber operational sooner than that deadline, resulting in achievement of the "Economic Performance Incentives" created by the Legislature in RSA 125-O:16.

Log
EXHIBIT NO. 14
9/18/13
S. ROBIDAS

PSNH has no control over economic factors that in recent time have shown great volatility. The Company, the State, and the country overall, have weathered nearly 18 months of recession. There are promising indicators that the worst is behind us. This year, very moderate summer weather added to the slow economy to produce low demand for power. As the economy gets back on track, it is likely that there will be increases in demand for energy and changes in soft energy prices that have recently been seen in the market. That recovery, coupled with normal weather patterns, will place upward pressure on energy and fuel costs.

These external factors are outside of the contractual costs of construction of the scrubber. As with PSNH's periodic energy service cost filings, a snapshot of such costs today will be different than those a day, week or month from now. It would be a waste of resources and money to require the Company to continually update projections of future costs based upon forecasts made during this period of significant volatility. Moreover, regardless of the result of such analyses, the legal mandate to install scrubber technology at Merrimack Station will remain intact.

Finally, PSNH is cognizant of the service requirements set forth in the Commission's regulations at Rule Puc 203.11. PSNH assures the Commission, as well as CLF, that it will adhere to the obligation to serve all filings in this proceeding on parties listed on the Commission's service list.

Sincerely,

Robert Bersak

Robert A. Bersak
Assistant Secretary and
Assistant General Counsel

cc: Service List, Docket No. DE 08-103

SERVICE LIST - EMAIL ADDRESSES - DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

Executive.Director@puc.nh.gov
bersara@psnh.com
desbiam@psnh.com
eatongm@nu.com
ehaffer@sheehan.com
Ken.E.Traum@oca.nh.gov
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Meredith.A.Hatfield@oca.nh.gov
mhoffer@clf.org
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Rorie.E.P.Hollenberg@oca.nh.gov
Stephen.R.Eckberg@oca.nh.gov

PSNH AE Newsletter

Long
EXHIBIT NO. 15
9/16/13
S. ROBIDAS

In This Issue:

Welcome, from your PSNH Account Executive
Time for customers to fight to maintain power rates and real customer choice!

FEBRUARY 12, 2009

Welcome, from your PSNH Account Executive
Time for customers to fight to maintain power rates and real customer choice!

N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-15
Witness William H. Smagula
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I. Background:

An initiative is underway to stop the PSNH "Clean Air Project", and if successful, New Hampshire customers will be paying more for their energy. You can help by letting your legislator know where you stand. Read on for details."

PSNH's "Clean Air Project" is the installation of a $457 million dollar wet scrubber on the Merrimack Station coal fired power plant. **The installation is required by current State law and will significantly reduce emissions at the plant.**

Merrimack Station serves about 30% of PSNH's customer energy needs for about five (5) cents per kilowatt hour or up to one half of the volatile market price for energy in New England. The Clean Air Project will make Merrimack Station one of the cleanest coal plants in the nation, while impacting PSNH's energy service rate by an average of (0.33) cents per kilowatt hour, or about 3%.

II. At Issue

Senate bill 152 is considered by some as a way to cancel the Clean Air Project. If the project is canceled, then Merrimack Station will close.

III. Consequences of Senate Bill 152

1. If Merrimack Station closes, power currently produced by the plant will be replaced by power purchased from the New England energy market. The cost of replacement power will be higher than Merrimack Station power. Further, this replacement power, could very well come from sources less environmentally friendly than the enhanced Merrimack Station.

2. PSNH will probably sell off all of it power plants removing the choice for customers to purchase power regulated by the New Hampshire Public Utilities Commission.

3. Hundreds of jobs will be lost in New Hampshire including PSNH utility jobs, power plant maintenance contractors, construction jobs, and others.

4. Higher electric rates will have a negative impact on New Hampshire businesses and families.

5. The rail system used to transport coal will lose revenue - this could impact plans for expanded rail service in New Hampshire and New England.

III. Opposition:
An initiative is underway, by folks including Stonyfield Farms' Gary Hirshberg, the Sierra Club, Conservation Law foundation, and others to either stop or delay the Clean Air Project. Project construction is underway, any delays will add costs.

IV. Why The Opposition?

1. Cost
Certain parties question the cost of the project.

2. Possible future environmental costs and Carbon Dioxide Emissions and Global Warming
The environmental opposition is concerned universally with Carbon Dioxide (CO_2) emissions from coal power plants and other sources, - and CO_2's impact on "Global Warming" and "Climate Change". Further, opponents claim that new Federal environmental requirements may result in additional costs at Merrimack

PSNH Account Executives

Phil Boivin, CEM, CFP
882-1387 x5252

Paul Hausmann, CEM
1-888-224-4300
X5164

Robert Krey
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Gary Lemay, PE
1-888-224-4300
x5440

Diane Monteith
634-2374

Tom Moody
1-888-224-4300
x5317

Craig M. Trottier, CEM
634-3191

Written By:
Craig M. Trottier
2/04/09

To Unsubscribe:
If you wish to be removed from our e-mail list, please reply to this email and type REMOVE in the subject line.

Station and the project should be halted until those costs are understood.

Points taken, but lets us look at reality.

V. Reality

1. Costs

The cost of the Clean Air project will be recovered through PSNH's Energy Service charge. However, customers are not required to purchase energy from PSNH. Utility customers are encouraged to source third party suppler offerings to get the price best available!

PSNH's Energy Service Rate tends to be very competitive, and provides "real choice" for customers. Merrimack Station is key to maintaining this advantage for New Hampshire. Also, third party suppliers do not seem interested in selling energy to New Hampshire families and small businesses. PSNH is the sole provider of energy to almost one half million residential customers, and small businesses.

Speculation on future Federal environmental costs for CO2 is just that - speculation. A Federal Program will impact every fossil fuel plant in the Nation - not just Merrimack Station. Also, here regionally we have the Regional Green House Gas Initiative, (RGGI), so environmental "cap and trade" programs are nothing new.

2. Customer Needs

Customer demand for power is predictable and must be met consistently and economically to maintain our economy and way of life. We all know what life was like during the recent ice storm.

Reality is that the electric needs of all our New Hampshire factories, businesses, and homes require service by base loaded, reliable, environmentally friendly power generation. Wind, solar, biomass and other alternatives are great sources of renewable energy, but power output from these sources is small, and can be sporadic and unpredictable.

Plants like Merrimack Station are key to providing fuel diversity of our base loaded power plants. Also, plants like Merrimack Station serve as a key bridge until the day we as a society can design and build a smarter power system.

Unfortunately it will take years even decades to transform the Nation's and New England's power system to a more sustainable, and environmentally "Smart" system. Until that time we need affordable reliable clean power so New Hampshire can compete nationally and internationally.

Now is not the time to cause economic damage to New Hampshire businesses and families.

Now is not the time to cancel or delay the Clean Air Project that will make Merrimack Station one of the cleanest coal plant in the United States.

Now IS the time to contact your legislator, business group, and others to encourage the Clean Air Project to go forward.

Now IS the time for substantive rational discussions on how to best transform our power system to a "smart" system, that maintains our way of life.

If the Merrimack Station Clean Air project is canceled, New Hampshire electric rates will increase, and jobs will be lost - which is the last thing we need right now. And frankly, closing the Merrimack Station will not make a dent in the huge and complex global warming / climate change issue.

Respectfully submitted.

Craig M. Trottier.

Please Contact Your Legislators

Governor / Senate Member	Mailing Address	District	Phone	Email Address
Governor John Lynch	Office of the Governor State House, Room 208 Concord, NH 03301	State-wide	603-271-2121	
The Honorable John S. Barnes	P.O. Box 362 Raymond, NH 03077-3062	17	603-895-9352	jack.barnes@leg.state.nh.us
The Honorable Peter E. Bragdon	P.O. Box 488 Milford, NH 03055	11	603-271-2675	peter.bragdon@leg.state.nh.us
The Honorable Sharon Carson	19 Tokanel Road Londonderry, NH 03053	14	603-271-2674	sharon.carson@leg.state.nh.us
The Honorable Jacalyn Cilley	2 Oak Hill Road Barrington, NH 03825	6	603-664-5597	jacalyn.cilley@leg.state.nh.us
The Honorable Martha Fuller Clark	107 North Main Street, Room 302 Concord, NH 03301	24	603-271-4152	martha.fullerclark@leg.state.nh.us
The Honorable Lou D'Allesandro	322 St. James Avenue Manchester, NH 03102-4950	20	603-669-3494	dalas@leg.state.nh.us
The Honorable William Denley	2305 Wakefield Road Sanbornville, NH 03872	3	603-522-3602	william.denley@leg.state.nh.us
The Honorable Betsi DeVries	107 North Main Street, Room 106 Concord, NH 03301	18	603-271-6933	betsi.devries@leg.state.nh.us
The Honorable Michael Downing	7 Derryl Lane Salem, NH 03079	22	603-271-8630	michael.downing@leg.state.nh.us
The Honorable John T. Gallus	292 Prospect Street Berlin, NH 03570-2137	1	603-752-1066	john.gallus@leg.state.nh.us
The Honorable Theodore L. Gatsas	P.O. Box 6655 Manchester, NH 03104-6052	16	603-668-1233	ted.gatsas@leg.state.nh.us
The Honorable Peggy Gilmour	126 Depot Road Hollis, NH 03049	12	603-465-2338	peggy.gilmour@leg.state.nh.us
The Honorable Margaret W. Hassan	107 North Main Street, Room 302 Concord, NH 03301	23	603-772-4187	maggie.hassan@leg.state.nh.us
The Honorable Matthew Houde	P.O. Box 66 Meriden, NH 03770	5	603-504-2744	matthew.houde@leg.state.nh.us
The Honorable	225 Tyler Road			

N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-16
Witness William H. Smagula
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Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request STAFF-01
Dated: 12/30/2011
Q-STAFF-012
Page 1 of 75

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

Question:
Please provide copies of all reports to the Legislative Oversight Committee on Electric Restructuring and other persons pursuant to the requirements of RSA 125-O:13,IX.

Response:
The requested information is attached.

Long
EXHIBIT NO. 16
9/16/13
S. ROBIDAS

Public Service Company of New Hampshire
Legislative Update – June 29, 2010

Merrimack Station
Clean Air Project

Cost, Contract, Construction, and Schedule Update

I. DOE Mercury Reduction Project at Merrimack Station – Unit No. 2

- Field testing ended in Q2, 2008
- Data compiled and submitted to DOE
- Conclusions: Only 40%-60% mercury reduction demonstrated; longer term testing would be required to further study operational impacts

II. Clean Air Project Update

- Engineering – 95% complete
- Commercial and Purchasing
  - Over 85 contracts are in place; approximately 5 remain to be issued
  - Contracts currently total $306 Million; remaining contracts could total up to $35 Million
- Permits and Approvals
  - All construction permits are in hand; EPA/NPDES liquid discharge permit application has been submitted
- Site Work
  - 240 craft workers are working on-site plus 95 management and support personnel
  - Over 30 companies are involved on-site
  - Major construction is heavily engaged in all areas
  - Project has been a significant boost to the local economy
  - Over 440,000 man-hours expended to date
  - Excellent safety record – no lost time accidents
- Schedule
  - On track to be done 1 year early – 7/1/12
  - 2010 is primarily a heavy construction year
  - 2011 continues with construction then transition to begin equipment and system testing and commissioning, and training
- Cost
  - Project cost continues to be in line with estimates; high confidence in not exceeding budget

Public Service Company of New Hampshire
Merrimack Station - Clean Air Project (CAP)
June 2011 Legislative Update
(September 2011 Updates Noted)

2006 June	2007	2008	2009 March	2010	2011 June	2011 Sept	2012	2013 July 1
The NH Legislature passed the scrubber law.			*DES issues the scrubber construction permit.*		*Clean Air Project 84% complete*	*Clean Air Project 90% complete*	*Project Completion expected mid-year*	*Statutorily required completion date*

I. CLEAN AIR PROJECT UPDATE

Engineering, Contracts and Procurement

- Engineering – 96% complete (98% complete as of Sept 2011)
- Contracts and Procurement
  - About 100 contracts have been issued; valued at approximately $330 M
  - Remaining contracts yet to be released- 4 or 5 at a value of $15-$18 M (All contracts have been issued.)

Construction and Site Activity Schedule

- Construction
  - In 2010, the majority of heavy construction was completed.
  - In 2011, installation of buildings and equipment continues to be finalized.
    Equipment start-up and system testing has begun.
    Integrated unit operations testing will begin this fall.
- Site Activity
  - Approximately 20 different contractors on site
  - Approximately 225 workers with 150 union craft labor on site (150 total as of Sept 2011)
  - Labor on site peaked at about 500 workers during last winter
  - Over 1,200,000 contractor man-hours expended
- Schedule
  - In 2012, performance testing to be completed with goal of full optimization mid- year.
- Economic value to New Hampshire
  - Use of over 50 local companies and hundreds of New Hampshire residents
  - As much as $50 million spent in the local economy

Public Service Company of New Hampshire
Merrimack Station - Clean Air Project (CAP)
June 2011 Legislative Update
(Additional September 2011 Updates Noted)

Major Project Milestones

Safety	Cost	Schedule
Over 1,000,000 man-hours without a lost time accident 1,200,000 man-hours through September 2011	Cost estimate reduced from \$457 M to \$430 M in October 2010	Project remains on track to be completed 1 year early.

II. DOE Mercury Reduction Project at Merrimack Station – Unit #2

- Field testing ended in Q2, 2008
- Data compiled and submitted to DOE
- Conclusions: Only 40%-60% unsustainable mercury reduction demonstrated with operational concerns identified.

Additional Updates

- The facilities continue to complete two mercury emissions stack tests per year at Merrimack 1, Merrimack 2 and Schiller Station .
- Methods for stack testing of mercury emissions and mercury continuous monitoring equipment continue to be developed although the accuracy still remains less than current continuous emissions monitoring (CEMS) equipment for SO2 and NOx emissions. This is not unexpected given the extremely small quantity of mercury emissions to be detected in a much larger exit flue gas stream.
- With the ongoing stack testing and the fuel testing and management, PSNH continues to investigate and test different coal blends to reduce mercury emissions.
- Achieved concurrence with NH-DES on the Clean Air Project's CEM strategy and functionality to support proper equipment procurement, installation and subsequent testing/monitoring.

June 2009

Public Service Company of New Hampshire

Merrimack Station
Clean Air Project

Cost, Contract, Construction, and Schedule Update

Cost & Contract Information

1. Total Project Cost Estimate (no change from figure contained in Summer, 2008 filings with U.S. Securities and Exchange Commission and N.H. Public Utilities Commission) **$457 million**

ITEM	*APPROXIMATE COST*
▪ Portion of Estimated Total Project Cost resulting from Contracted Goods and Services	$345 million
▪ Portion of Estimated Total Project Cost from Investment Carrying Costs (Allowance for Funds Used During Construction [AFUDC])	$55 million
▪ Portion of Estimated Total Project Cost from Fees & Payments	$8 million
▪ Internal Labor Costs	$7 million
▪ Indirect Costs and Contingencies	$42 million
TOTAL	$457 MILLION

2. Status of Contracted Work

   Portion of Estimated Total Project Cost for Goods and Services under Contract as of this Date: *Approximately $256 million (about 75% of total estimated project contract costs)*

Major Contracts Executed and in Place include:
- *Program Manager Services (Engineering Design and Construction Management)*
- *Flue Gas Desulphurization System (Scrubber system)*
- *Material Handling System*
- *Site Preparation*
- *Chimney*
- *Wastewater Treatment Facility*
- *Foundation Installation & Misc*
- *Electric Power Distribution U/G*
- *Booster Fans and Motors*

Contracts Remaining:
- *No major contracts remain*
- *A number of minor contracts including ductwork, dampers and piping; plant control systems; continuous emissions monitoring system; etc.*

Contract Structure: *Majority of costs are controlled by fixed price contracts, reducing future escalation exposure.*

Construction

3. Status of Construction

Major Construction began on March 9, 2009 with the receipt of the Temporary Permit

Number of jobs created:
- *approximately 150 - 200 contractors on site at this time*
- *at peak construction, 300-400 jobs*

New Hampshire contractors and companies on site at present:
Contractors on site at this time include:
- *Carpenters*
- *Laborers*
- *Iron workers*
- *Operators*
- *Concrete finishers*
- *Pipe fitters*
- *Electrical workers*

(Representing members of the following unions: New Hampshire Local 668, Local 118, Local 7, Local 98, Local 3, Local 490. Local 131, Local 669, Local 609, Local 4
Massachusetts Local 127, Local 549, Local 687, Local 1485, Local 534, Local 1282, Local 70, Local 1, Local 107, Local 108, Local 243, Local 537, Local 387, Local 175)

New Hampshire companies on site at this time:
Over 30 NH companies are providing primary services to the project with over 25 additional support companies (including as shown below)

- *Aggregate Industries*
- *Ayer Electric*
- *Eastern Analytical, Inc*
- *George Cairns & Sons*
- *New Quality Fence Corp.*
- *North Branch Construction, Inc*
- *Redimix Concrete Inc.*
- *Scanada International Inc.*
- *TF Moran*
- *Weaver Brothers*

Schedule

4. **Status of Schedule**

Effective Date of Scrubber Law: June 8, 2006

Statutory Mandatory Project Completion Date: July 1, 2013

Current Estimated Project Completion Date: June, 2012

Estimated Benefits to Customers from Early Completion (June 2012):

- ***ECONOMIC***
  RSA 125-O:16 Economic Performance Incentives: Customers benefit from early emissions reduction credits that can be converted to fungible SO2 allowances

  AFUDC Carrying Costs: At end of project, AFUDC is high, so completing the work ahead of schedule can save millions of dollars.

- ***ENVIRONMENTAL***
  Estimated Additional Emissions Reductions Achieved with an Early Project Completion:
  - *Eliminates over 220 pounds of mercury;*
  - *Eliminates over 31,000 tons of SO2;*
  - *Provides additional reduction to particulate emissions.*

Note: *These early completion benefits to customers are contingent upon the estimated early project completion date. Any delays in the project, whether from technical, regulatory, or judicial causes, will reduce these projected benefits.*

Clean Air Project Permit Overview

Below is a list of the majority of permits obtained to date.

Federal

FEDERAL AVIATION ADMINISTRATION (FAA):
- Chimney
- Temporary Cranes.

ENVIRONMENTAL PROTECTION AGENCY (EPA):
- Storm Water Discharge – Notice of Intent

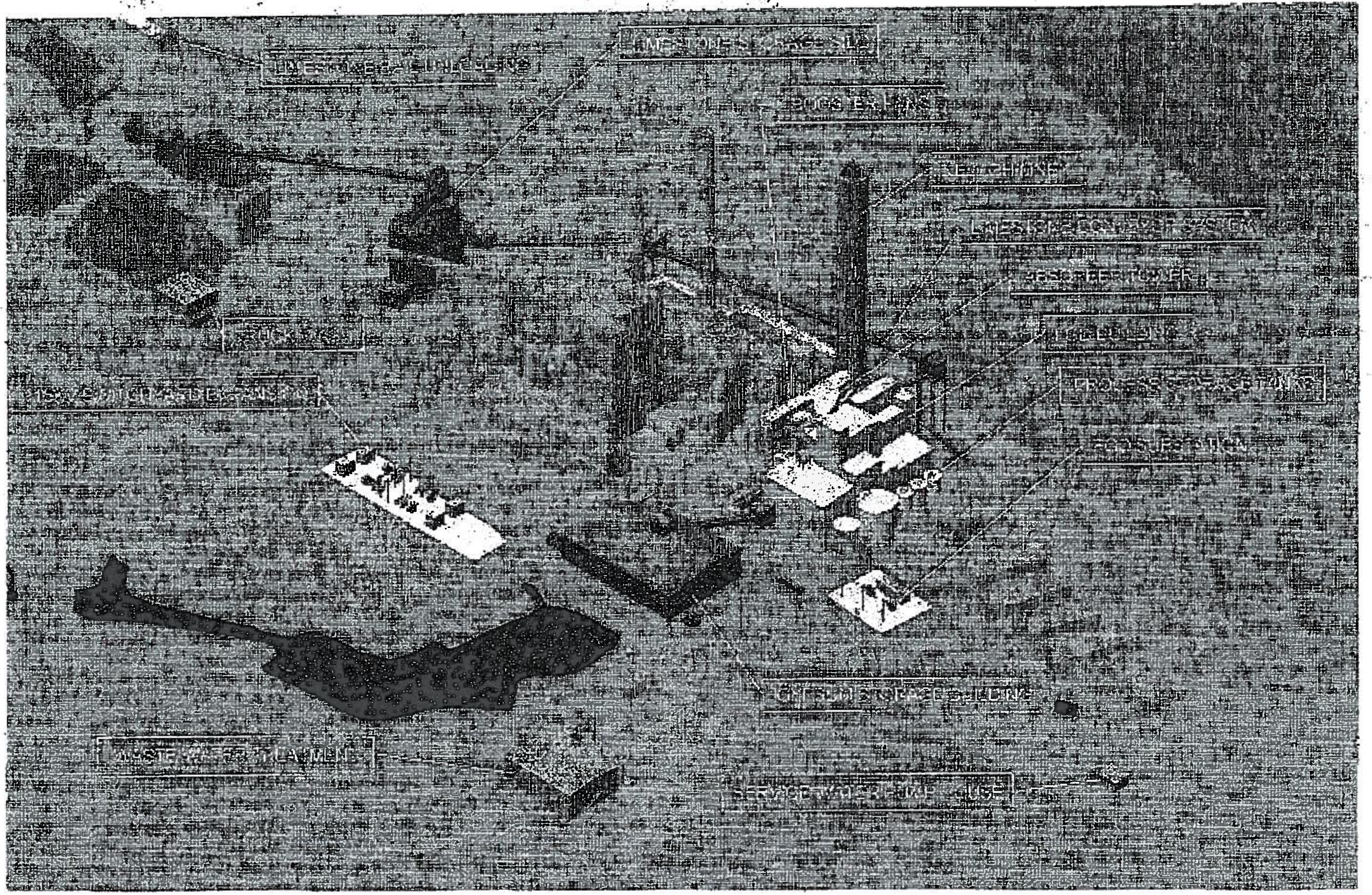
State

NEW HAMPSHIRE DEPARTMENT OF ENVIRONMENTAL SERVICES (NH DES):
- Air Permit
- Styrene Air Permit (Chimney Liner Fabrication)
- Phase 1 Alteration of Terrain Permit
- Phase 2 Alteration of Terrain Permit
- Asbestos Demolition/Renovation Notification
- Approval of Construction of Guard Station Septic System
- Exemption for Vested Rights Shoreland Protection
- Approval of North Septic System
- Wetlands Permit/Dept. of Army Corp. of Engineers / Dredge and Fill Permit
- Approval of South Septic System (CMA)

Local

TOWN OF BOW:
- Phase 1: Site Plan Review 203-08; Wetlands CUP 410-08; Aquifer Protection Conditional Use Permit (CUP) – 411-08
- Phase 2: Site Plan Review 203-08; Wetlands CUP 410-08; Aquifer Protection CUP – 411-08
- Construction/Building Permits:
  - Chimney Foundation
  - Absorber Vessel Foundation
  - Scrubber Bottom Mat Foundation
  - FRP Building Foundation
  - Chimney Shell
  - Scrubber Top Mat
  - Guardhouses and Attendee Booths
  - Application for Driveway Permit
  - Chimney Building Structure
  - Installation of Construction and Storage Trailers
- Demolition Permits: Unit 1 Original out Buildings, Plant Entrance and Guard Office
- Special Exceptions and Variances:
  - #106-08 Special Exception – Gypsum Storage Bldg.
  - #107-08 Special Exception – WWT.
  - #106-09 Special Exception - FRP Bldg.
  - #108-08 Limestone Silo (1) Variance; and Silo (2) Variance
  - #109-08 Wet FGD Bldg Variance

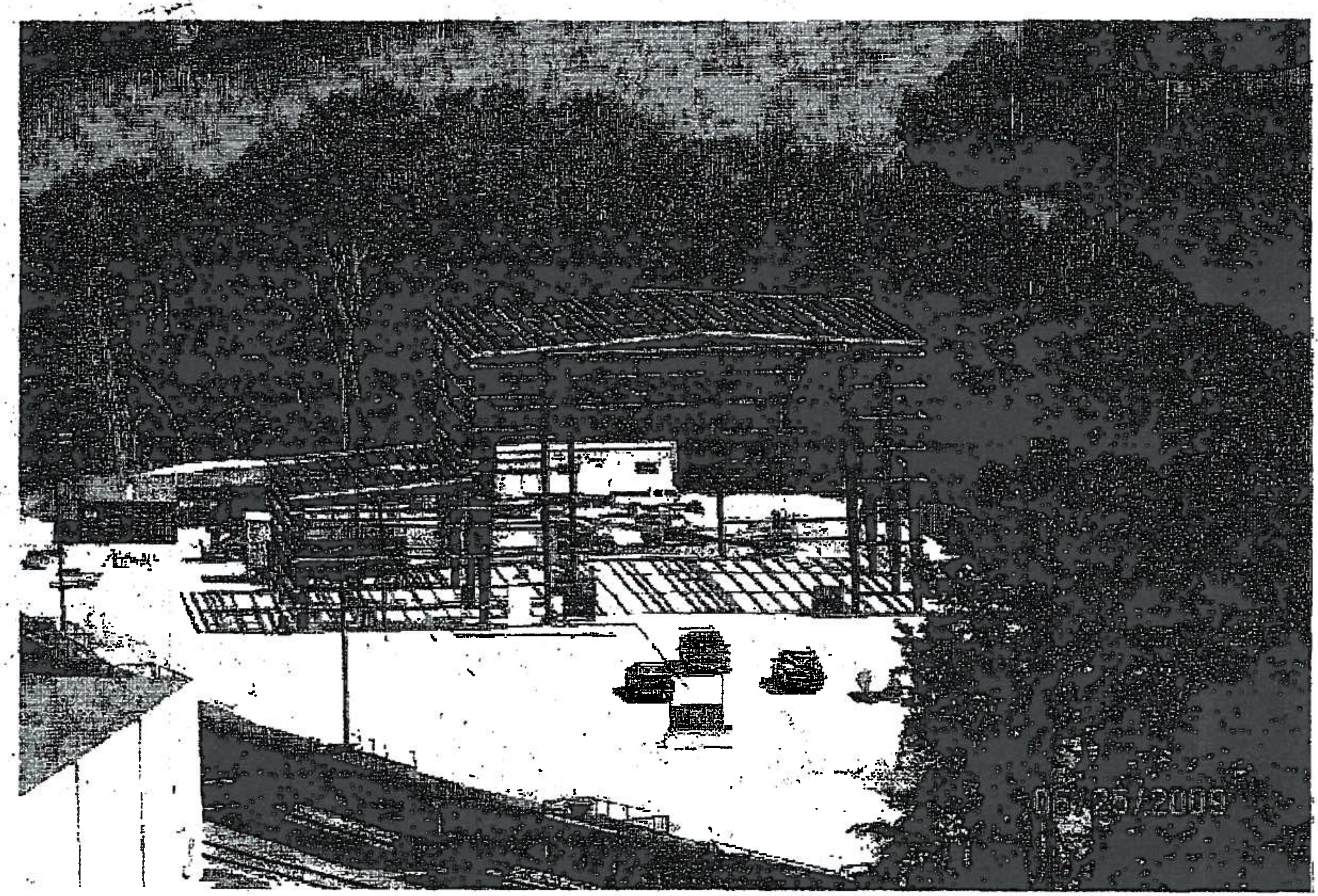
PUBLIC SERVICE OF NEW HAMPSHIRE
MERRIMACK CLEAN AIR PROJECT



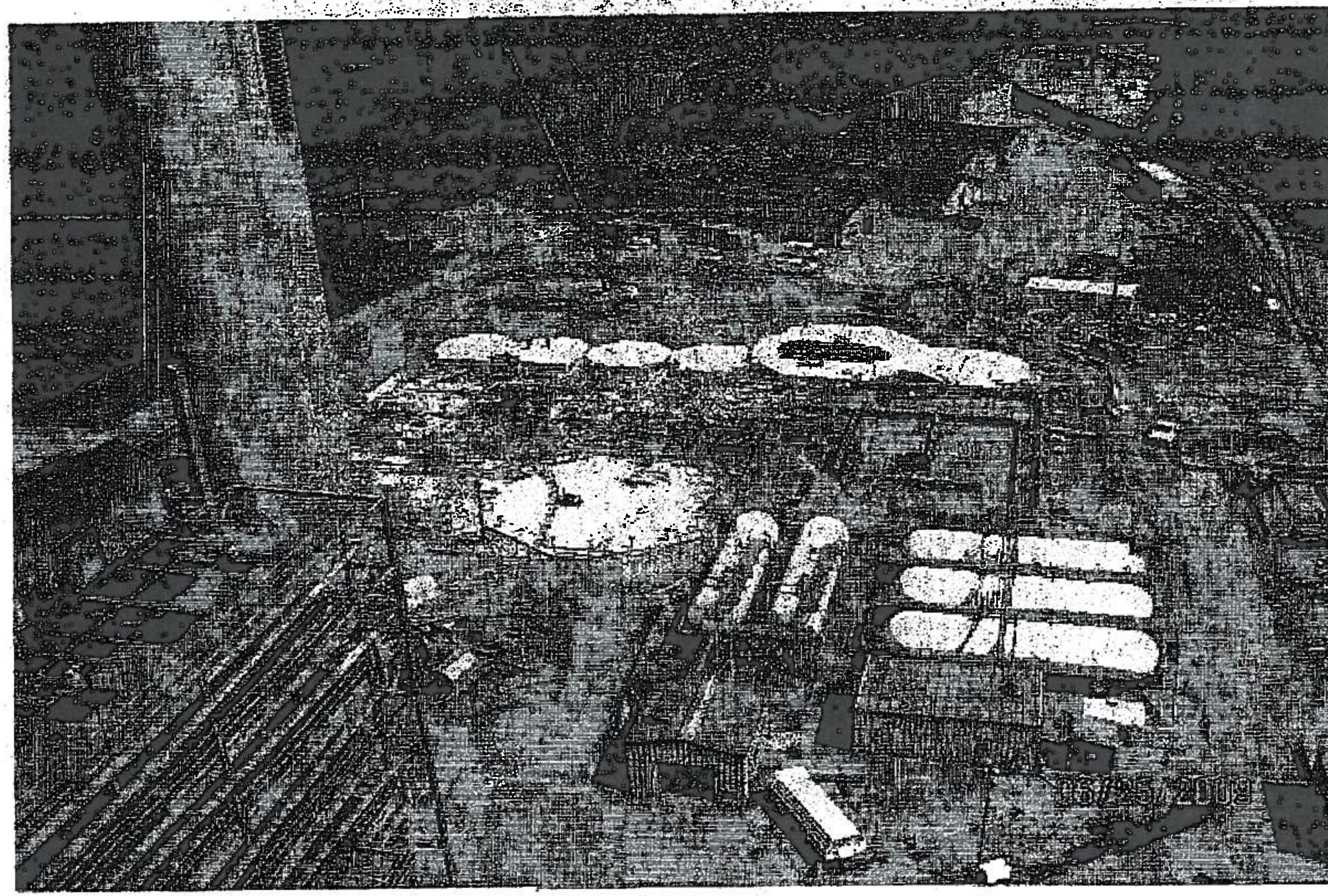
June 4, 2009 Start of Concrete Placement on Chimney Shell

Chimney Shell as of June 25, 2009

Stack Liner Fabrication Area



Major Foundations for the FGD Building including the Absorber Vessel



Merrimack Station

Unit 2

Activated Carbon Injection - Overview and Status

- Sorbent Injection Trial Results and background
- DOE Project Excerpts

Jan-05

Merrimack Unit 2 - Sorbent Injection Trial to Reduce Mercury Emissions

Test Results as presented by Sorbent Technologies (STC) November 2005

Method	Initial Summary of Results - Nov 05	Revised Summary or Results- Jan 05	Change in Mercury Emissions Reduction	
SCEM (semi continuous emissions monitoring)	29%	29%	No change	
OHM (Ontario-Hydro method)	43%	11%	-32%	note 3
Method 324 (EPA alternative method)	25%	26%	1%	

Notes-

1. Changes were a result of the QA/QC (quality assurance/quality control) process required and completed by NHDES.
2. Three measurement testing methods were used. Both the OHM and Method 324 were stack/duct testing methods sub-contracted by STC.
3. A number of analysis and reference errors by sub-contractor completing the OHM method were identified by NHDES.

   This correction resulted in significantly less mercury removal calculated by this method.

The corrected data shows mercury removal during the trial was 20%+/-10%

NETL

Evaluation of Control Strategies to Effectively Meet 70 –90% Mercury Reduction

PSNH Merrimack Station
Site Project Kickoff Meeting

August 24, 2006

Jean Bustard, Tom Campbell - ADA-ES, Inc.
Bill Smagula, Paul Raichle, Laurel Brown - PSNH

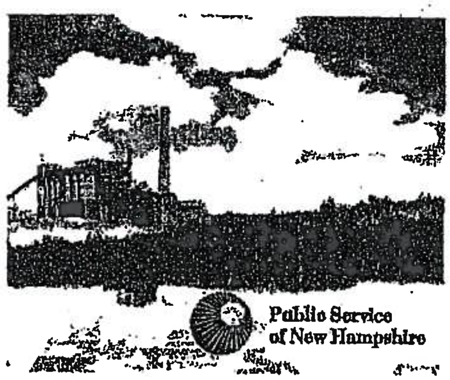
DOE/NETL Project Manager: Andrew O'Palko

Merrimack Unit 2

MK2: 335 MW

Coal: Eastern Bit and
Venezuelan Blend
~50/50 split
1.0 – 1.3% sulfur
(1.2%S is current target)

Cyclone Boiler
SCR
C-ESP



ADA-ES

Project Goals

- Evaluate the capability of SO_3 tolerant sorbents to achieve 70 to 90% mercury removal
- Evaluate the effect of co-benefits from SO_3 mitigation on mercury control, and the balance of plant benefits from lowered flue gas temperatures of increased plant efficiency and overall reduced emissions
- Evaluate the impact of sorbent injection on ash disposal
- Support the education and transfer of information and results to local and state interests groups

ADA-ES

DOE Areas of Interest

- Testing with a cyclone boiler
  - *Limited testing data from Sorbent Technologies available from Summer 2005*
- High flue gas temperatures (330 - 350°F)
- Smaller SCA ESPs
- New SO_3 tolerant activated carbons
- Effect of different coal blends on mercury removal
- New technologies??? (Mobetec/MinPlus)

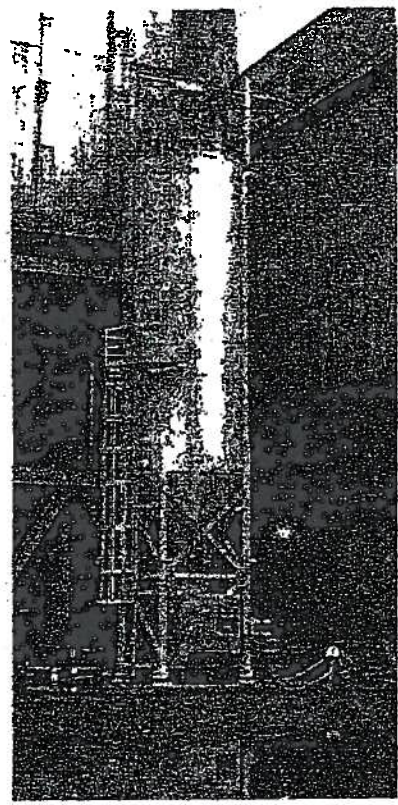
ADA-ES

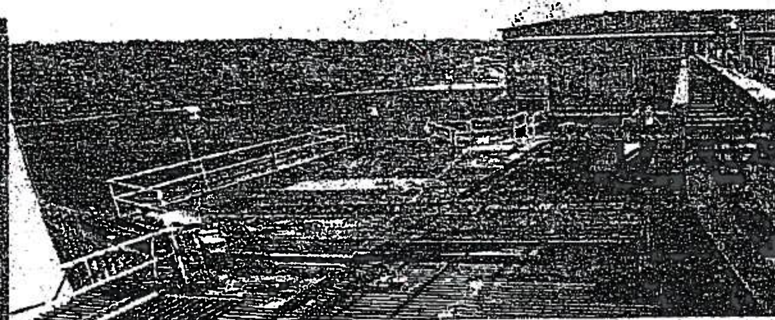
Project Tasks

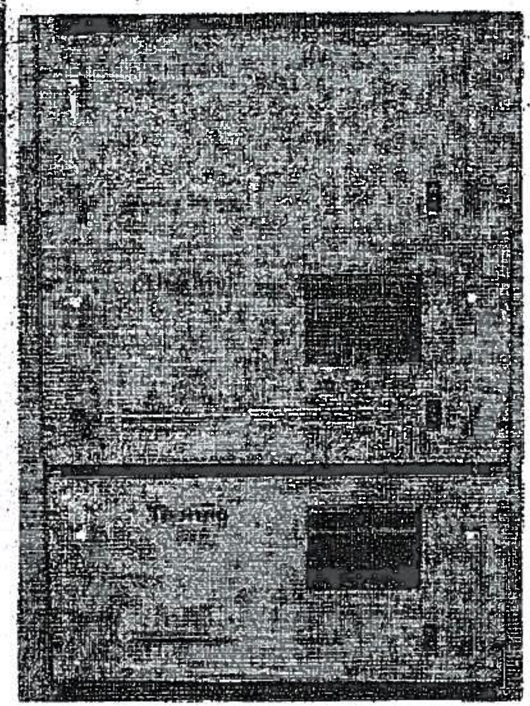
1. Pre-Test Planning
2. Design for site-specific needs and install equipment
3. Field testing
   - Sorbent Screening Tests
   - SO_3 Co-Benefits Analysis
   - Baseline testing
   - Parametric testing
   - Choose Long-Term Test Parameters
   - Long-term testing
4. Coal, Ash, and By-Product Sample Evaluation
5. Technology Transfer
6. Management and Reporting

ADA-ES

Evaluation of Sorbent Injection for Mercury Control







NETL

Public Service of New Hampshire

The Northeast Utilities System

Project Review 2007

June 26, 2007

DOE Cooperative Agreement DE-FC26-06NT42780
DOE/NETL Project Manager: Andrew O'Palko

ADA-ES

Mercury Control Evaluations: ACI Timeline

Pilot Testing

1991 **EPRI**: Comanche

1995 **EPRI:** Hudson
DOE/EPRI: Comanche

EPRI: Boswell, Sherco, Pleasant Prairie
Nanticoke, Miller, Coal Creek, Others
DOE/EPRI: Valley, Powerton

2001 **DOE Phase I:** Pleasant Prairie, Gaston,
Salem Harbor, Brayton Point)
EPRI: Abbott, Laskin, Stanton, Coal Creek
DOE Gaston

Full-Scale Testing

2004 **DOE Phase II:** Holcomb, Stanton, Yates,
Meramec, Leland Olds, Laramie River, St. Clair,
Buck, Monroe, Antelope Valley, Conesville,
Independence, Big Brown, Council Bluffs,Louisa,
Dave Johnston, Portland, Lee, Miami Fort

2006 **Industry:** Multiple
DOE CCPI: Presque Isle
DOE Phase III: Hardin, Hawthorn, Mill Creek,

2008 Limestone, Merrimack **Commercial:** 10+

DOE: No funding for 2008

ADA-ES

Mercury Control Evaluation: PSNH Merrimack

2006

DOE Phase III Award: Merrimack

Kick Off Meeting, Test Plan
Equipment Procurement

Baseline: October
Co-Benefit: October - November
Parametric: November

2007

Parametric: January - March

Balance of Plant: March
PAC Silo Install: May - June

Long Term Test: June

2008

ADA-ES

Why Merrimack?

- Cyclone Boiler: relatively small fleet
  - Different Combustion Process
  - Different Ash Characteristics
- SCR: Flue gas characteristics
- High Flue Gas Temperatures
- Dual Particulate Collection Devices: ESPs

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Laboratory/Pilot Scale Studies

- Performance of Powdered Activated Carbon (PAC) influenced by the flue gas characteristics
  - APC Configuration
  - Coal Type
    - Halogen content (Cl, Br, other)
    - Sulfur content (SO_3)
  - Flue Gas Temperature
  - SO_3
    - From coal
    - SCR
    - Flue gas conditioning

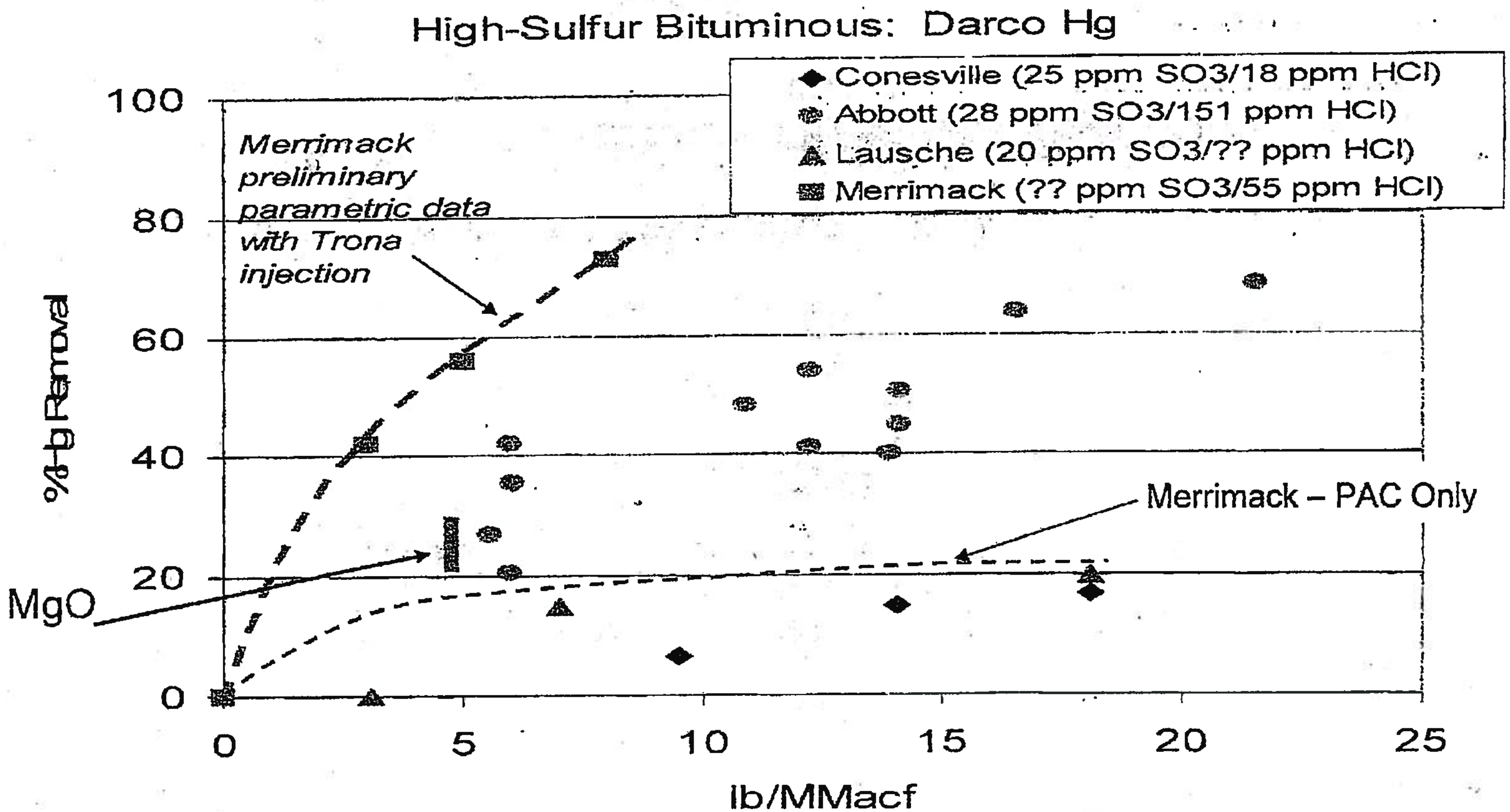
ADA-ES

Baseline Results

- Hg varies (range was 5 to 10 μg/m^3 from Aug 06 through Jan 07)
- No removal across the ESP
  - Based on CEM, STM
  - Low Hg levels in ash analysis (10 ppb)
- OH within 20% of Baseline CEM and STM results
- On and off site analysis of STM traps correlate well with inlet CEM
- >80% Oxidation of Mercury

ADA-ES

Parametric Test Results



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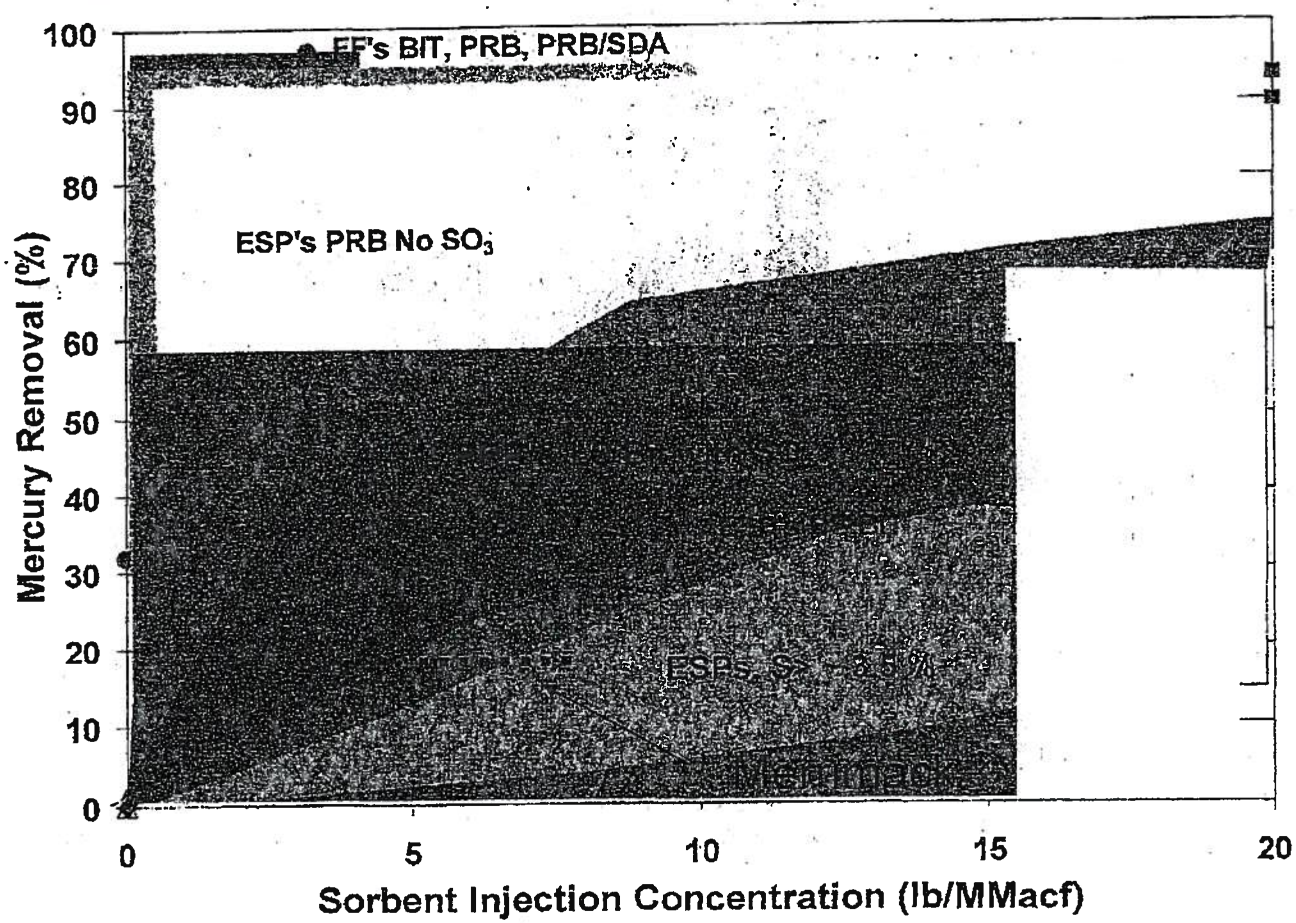
Issues Remaining for Merrimack

- Ash Disposal
  - Plant has set up a schedule to dispose of the ash from the Original and Supplemental ESP hoppers separately
- NSR triggers – PM: 25ton/yr - ~7lb/hr – 98% ESP eff.
- Balance of Plant
  - Long term effects

ADA-ES

Mercury Reduction Trends with ACI on FF's and ESPs



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Ongoing Testing

- PAC Performance Enhancements
  - Fine PAC
  - Specialty Carbons and Blends
  - Co-Injection with Alkali Materials
  - Injection Location
- Balance of Plant Issues
  - Additional TOXECON II testing
  - Long Term testing of PAC injection upstream of an APH
  - Additional testing of Adsorbents for SO_3 control
  - General Specifications for TOXECON system designs

ADA-ES

Ongoing Testing

- Ameren's Labadie Power Plant
  - PRB coal
  - ESP
  - SO_3 FGC
- PSNH Merrimack Power Plant
  - E. Bit Coal + Offshore Supply
  - SCR + ESP
- RMP Hardin Generating Station
  - PRB Coal
  - SCR + Dry Scrubber + FF
- We Energies Presque Isle
  - PRB Coal
  - HS ESP + TOXECON

ADA-ES

Questions?

Jean Bustard or Tom Campbell
ADA-ES, Inc.
(303) 734-1727
jeanb@adaes.com
tomc@adaes.com

ADA-ES

PSNH Legislative Update- June 18, 2008*

Update relative to the reduction of mercury emissions at PSNH Coal Fired power plants as outlined in HB1673.
As required by HB 1673 (RSA 125-O:13 Compliance- Paragraph IX) PSNH shall report by June 30, 2007 to the legislative oversight committee on electric utility restructuring, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee, on the progress and status of:

1) Achieving early reductions in mercury emissions:

DOE Mercury Reduction Project at Merrimack Unit 2

- **Program Schedule Fall 06 – Spring 08**
  - Completed Parametric Testing Nov 2006
  - Completed Long Term Testing April 1, 2008
  - Used various combinations of sorbents to assess effectiveness
  - Varied rates of injections
  - Varied location of injection points
- **Long term Test Evaluations**
  - Long term test – Fall 2007 thru March 2008
  - Equipment performance
  - Balance of Plant Issues
  - Mercury Removal Performance
- **Measurement tools and methods**
  - Completed sorbent trap measurements
  - Installed and monitored Hg CEMs
- **Results of Parametric tests**
  - Initial injection plan 10 – 30%
  - Enhanced injection resulted in a wide variation of results
  - Sustainable results will depend on the ability to resolve balance of plant issues

2) Installing and operating the scrubber technology:

CLEAN AIR PROJECT UPDATE

- **Engineering**
  - Projects defined in 5 major components
  - Specifications developed for 4 key components
- **Commercial and Purchasing**
  - Program Manager Hired Sept 2007
  - Scrubber Island and Chimney proposals are in negotiations
  - Vendor Proposals requested and received for Wastewater Treatment Facility and Material Handling System
- **Review, Permits and Approvals**
  - NHDES – May 12 presentation
  - Temporary Permit expected October 2008
  - Town of Bow –Local permitting
  - Regional Planning Commission
- **Site work**
  - Existing oil tank removed
  - Site surveys and studies completed
  - Warehouse construction underway
  - On-site engineering facilities completed
- **Schedule and Costs**
  - Tie-ins: MK#1 Fall 2012, MK#2 Spring 2013
  - Project Costs will be updated with review of major equipment bids

*year corrected to reflect June 2008 update

PSNH Legislative Update- June 26, 2007

Update relative to the reduction of mercury emissions at PSNH Coal Fired power plants as outlined in HB1673.

As required by HB 1673 (RSA 125-O:13 Compliance- Paragraph IX) PSNH shall report by June 30, 2007 to the legislative oversight committee on electric utility restructuring, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee, on the progress and status of:

1) Achieving early reductions in mercury emissions:

DOE Mercury Reduction Project at Merrimack Unit 2

- **Parametric Testing**
  - September – November 2006
  - Used temporary equipment set-ups
  - Used various combinations of sorbents to assess effectiveness
  - Varied rates of injections
  - Varied location of injection points
- **Optimum plan for long term test**
  - Engineered and purchased equipment for long-term test and post DOE use
  - Installed and commissioned new equipment
  - Long term test – June to November 2007
- **Measurement tools and methods**
  - Completed sorbent trap measurements
  - Installed and monitored Hg CEMs
  - Identified testing methods for long-term test including new EPA methods
- **Results of Parametric tests**
  - Initial injection plan 10 – 30%
  - Enhanced injection plan scattering of individual points between 30 – 60%
  - Sustainable results to be determined during long-term test

2) Installing and operating the scrubber technology:

CLEAN AIR PROJECT UPDATE

- **Engineering**
  - Specifications developed for key components
  - Possible Site plan layouts developed
  - Equipment options identified
  - Vendor lists and contacts established
  - Industry impact of high number of scrubber installations analyzed
- **Commercial and Purchasing**
  - Contract Strategy determined and approved
  - Program Manager Specification written
  - Program Manager out to Bid
- **Permits and Approvals**
  - Temporary Air Permit Application submitted to NHDES-ARD June 7, 2007
  - Town of Bow presentations and submittals underway
  - Company financing approvals initiated
- **Site work**
  - Existing oil tank removal completed
  - Site surveys completed
  - South Yard studies completed

Clean Air Project

Merrimack Station

March 31, 2010
NH Public Utilities Commission
Docket 08-103 Informational Session

Public Service of New Hampshire
The Northeast Utilities System

ATTACHMENT B

N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27-17
Witness William H. Smagula
DO NOT REMOVE FROM FILE

Date: March 13, 2009
Time: 9:00 a.m.
Room: Reps Hall

The Senate Committee on Energy, Environment and Economic Development held a hearing on the following:

SB 152 relative to an investigation by the public utilities commission to determine whether the scrubber installation at the Merrimack Station is in the public interest of retail customers.

Members of Committee present:

Senator Fuller Clark
Senator Merrill
Senator Lasky
Senator Cilley
Senator Odell

The Chair, Senator Martha Fuller Clark, opened the hearing on SB 152 and invited the prime sponsor, Senator Janeway, to introduce the legislation.

Senator Harold Janeway, D. 7: I won't begin in 1960, 49 years ago, when the first unit began operations. Rather I'll focus on the legislative history that is relevant to what we're talking about here today.

It begins in 2002 with House Bill 284, which was known as the New Hampshire Clean Power Act. Gary Long was there for that, and has been in attendance at all subsequent issues related to this.

Representative Jeb Bradley presented his bill to this same Committee, one member of which now sits with distinction on the Public Utilities Commission. In Bradley's testimony, he discussed trading pollution credits, energy efficiency initiatives and mercury. And here's what he said.

He said: "...and lastly you will hear discussion that we're not doing enough on mercury control." This was back in 2002. "Mercury is a serious pollutant, it is a potent neurotoxin, has significant adverse health effects, particularly for women of childbearing age and for prospective babies."

Long
EXHIBIT NO. 17
9/16/13
S. ROBIDAS

Testimony in the House indicated that the likely emissions from these plants range from 30 lbs. of mercury emitted to as much as 330, and it was our DES that estimated the higher number. In an EPA website, the lower number. It is rational, therefore, to do what this bill proposes to do: test PS New Hampshire's facilities for the actual amount of mercury, wait for the EPA regulations on mercury, which are expected to occur in the next several years, and then devise a strategy that would have to come back to this Legislature at some point in time for enactment in the future.

"That," he said "is a rational response, especially in light of what you folks and those of us in the House have done, which is fight for lower mercury levels from the waste to energy facilities."

So, the issue did come back to the Legislature four years later, and it appeared in the form of House Bill 1673, which had subsumed a Senate bill, it was Senate Bill 128, with a similar thrust. And that was the bill that gave Public Service of New Hampshire its marching orders in June 2006.

I want to just quote from the summary of that particular meeting, when Senator Odell brought the bill to the floor on the Senate. He said: "This bill provides for an 80 percent reduction of mercury emissions from coal burning power plants by requiring the installation of scrubber technology no later than July 1, 2013, and provides economic incentives for earlier installation and greater reductions in emissions." Incidentally, Senate Research has compiled a full history of those two bills. It's a rather substantial packet, but certainly you'll want to have that available to you as a reference as you work your way along.

Clearly, the most frequently asked question that I get, in various forms, is essentially "why stir the pot? The company is moving ahead as directed." "Get over it," some of them add. And so I want to try to respond to that question this morning.

First of all, the projected cost has, as I think everyone knows, risen sharply, about 80 percent. I personally don't feel that that's the most important issue, and it's one that I suspect will be answered fairly fully today, but it was one that certainly got everyone's attention. An extra $200 million plus is a sizeable sum. But I think more important, at least to me, is the fact that there have been major changes in the fundamentals that do bear on this issue since that particular action was taken. And so I would ask, in response to the question of "why stir the pot," I would ask, would you invest today based on what you knew two and a half years ago or what you know now? And to me the answer is, I would want to take into consideration those things that

CSM

are known now before making my decision. So I'm essentially firmly in the camp of those who believe that we should be open to new information.

So then the question is, what is new and what is relevant? My answer, I will try to keep it brief, but is fairly detailed. First of all, the industry is undergoing much change, and more in recent years than probably in multiple decades prior, to when it was a fairly simple business and was all regulated. Oversimplified, back in the perhaps good old days, the more power you sold, the more plants you could build, the larger the investment base on which you could earn a return. This was the "live better electrically"era. Then came deregulation and things got messy. But none of that is particularly new.

But there are new things that have developed over the past two and a half years that we really do need to think about. First of all, the environmental pressures have ramped up considerably. Even with the Bush Administration's denial of many environmental issues and climate change, these things have built up during the past few years and it is clear with this change in administration that we now have, we now face considerably more regulation and more pressure to act. Coal plants, the best of them, still emit substantial pollutants of various sorts, as you well know. They're a major source and are going to come under special pressure.

Another issue that's become substantially more of a factor than it was in past years is this whole question of energy independence. Where do we get our energy from? And that brings in the drive towards renewables. As many of you know, we have a goal of 25 percent renewables here in New Hampshire by 2025. We're a fair ways from that now, but that's something that clearly is going to be a factor, and coal definitely is not a renewable. The carbon dioxide, which has been a major force and continues to be a major force in climate change, is going to come under pressure. I think there's, most people would agree, there's a high likelihood that we will see a cap and trade program from, which attempts to deal with that issue. The evidence for climate change, unfortunately, continues to grow.

Efficiency is something that has become more evident over the past few years. Efficiency measures are now paying off, and we're actually seeing a change in the long term growth curve in the demand for electricity as a result of that. But the whole efficiency thing is really just beginning to break through. The potential savings in commercial buildings, in homes, and these aren't efficiencies that mean turning off your heat or turning off your lights, it's just investing in efficiency measures that are going to make a substantial difference and are going to bend the growth curve as we look out into the future.

So the slowdown in demand for electricity that we've seen over the past year or more, while it's been exaggerated by the slowdown in the economy, has more to it than that. Texas Utilities for instance, one of the major utilities in the country, I think reported a six percent decline in sales last year, closing a number of plants. This is something that's going on industry-wide. So we have to think about the effects of efficiencies. The Obama Administration, as I've mentioned, is now pushing incentives for greater sustainability and connected to that, I would say, is the prospect for a substantial number of jobs. Many of the programs that we've seen in the stimulus program that will come to New Hampshire will bring some money to areas where there can be a lot of good jobs and a lot of substantial benefit.

Another thing that we have to factor in is the likelihood of high, increasing standards, higher thresholds for mercury, among other things, that will face us in the period ahead. So I think it's important when we look at this issue that we keep that in mind. I don't see this as really two paths that diverge, one good, one bad. We're still, it's still really one path, but I think the path that we're moving along is moving through a landscape that has changed dramatically.

So the question is, do we adapt and adjust to that changing landscape or do we essentially go ahead without consideration to what's happening all around us? And that is essentially what needs to be studied. I know that it's hard to swallow, even for the short term, because it's a major project and it's been a long time in building and it's underway. But I feel very strongly that what we're seeking here, which is a study, a relatively short study, is necessary. And I think that that's the least that we can do for the ratepayers. I'm reminded of an old musical which was called "The King and I," which was about the king of Siam and he had a governess he brought in to raise his kids. And the governess taught him that most of his views were totally out of line with reality and eventually he was brought around to her way of thinking, and there was a song in that where the refrain was, "I think I want to think it through again." So all I'm asking is that you give us a chance to think this through again. Thank you.

Senator Martha Fuller Clark, D. 24: Thank you very much, Senator Janeway. Are there questions from the Committee? Senator Odell.

Senator Harold Janeway, D. 7: Good morning.

Senator Bob Odell, D. 8: I appreciated very much the history of the background on this legislation, because I think that's very important, about where we've come from. And I was going to ask that question had you not raised that. But I also want to add a couple of statements and then ask for a response.

And that is that in 2006, the vote on the Senate floor was 22-2 to go forward with the scrubber, and let me put it in the simplest of terms. There was a different party in charge at that time, the Republicans were in the majority. I chaired this Committee, for example. We became convinced, that is some of us, that the public health danger to children and young women of childbearing age was so compelling that we needed to take action right then. Two hundred and fifty million dollars to me sounded like a huge amount of money, huge amount of money. But I think of the child that is born today or a mother about to conceive in Manchester or in some other community east of here, and I say if that child's public health interest, the prevention of cancer, was to be $1.00, I would be for it. But for each of those children, if the price was $2.00, I would still be for it. This to me is a public health issue. We fought very, very hard to get consensus within both parties to pass this bill. We understood there would be new technology, new advances, but we didn't want to do exactly what's happening in this room today, consider putting it off one more time, over and over again.

And it's come me not as a debate about public health, but when a lobbyist or the advocates of your bill drive to Lempster, New Hampshire and sit down and say we represent commercial ratepayers. And I say, who ratepayers? Well, 28 ratepayers, commercial ratepayers. And I say okay, I represent 55,000 people here who are worried about jobs, they're worried about public health, they're worried about cancer, they're worried about pollution. And I just have the greatest trouble of going back and looking at what we went through in 2006, which I think was one of the high points of my time in the State Senate, passed this bill, and then come today, have somebody say, oh, but you might have not known enough to go forward.

I know something about young people and children who suffer with cancer. We had a presentation yesterday morning about CHAD. We saw two children with cancer. If I were to be here today and not do everything I can to get this scrubber up, inadequate as it may be, I think I would have failed the mission we adopted as a policy of this State of New Hampshire in 2006. I just come to you today and I would say, Senator, would you consider letting us go ahead with the scrubber, meanwhile, go ahead with the study on the side. Three months, six months, whatever it is. I'd rather have you do a good study, but let's get on to the scrubber from the standpoint of public health, nothing else. Two hundred fifty million, five hundred million dollars, children, women who could be pregnant, cancer, I just can't turn back.

Senator Harold Janeway, D. 7: That's a good statement and I can't disagree. There's nothing in this bill that actually says stop. It says please study. And I agree about mercury. I think, when I think about dealing with this mercury and you think about trying to remove whatever, 80 percent of 140 lbs. out of, I'm not sure of the arithmetic, I think it's a billion pounds of coal, I don't see how it works, but it does take some major action to do it. So, as I say, please, the bill does not require a halt.

Senator Martha Fuller Clark, D. 24: Follow up?

Senator Bob Odell, D. 8: That's fine.

Senator Martha Fuller Clark, D. 24: Are there additional questions from members of the Committee? Thank you very much, Senator Janeway.

Senator Harold Janeway, D. 7: Thank you, Senator Clark.

Senator Martha Fuller Clark, D. 24: I'd now like to call upon Senator Gatsas.

Senator Theodore L. Gatsas, D. 16: Thank you, Madam Chairman, members of the Committee. I'm Senator Ted Gatsas, I represent the towns of Dunbarton, Bow, Hooksett, Candia and Wards 1, 2 and 12 in Manchester. I'm here to speak against both the bill and the amendment. I think the Committee needs to consider some things. You have an amendment before you that says, and we've heard that possibly they could report out in 90 days. There was different testimony that came out in the House hearing a few days ago. At the end of 90 days when you get that report, what do we plan on doing? Calling a special session to close the project? Being here in the same position we are today? We have a project that's going at full force. By October, it's going to be well into the project. So what are we attempting to do at that time?

And Senator Odell, I'd like to, because history is very important. And I think that we need to talk about the history of this bill from the beginning, because in the Senate, House, Senate Bill 128 was before the Senate and I was on Energy, on that committee, and Senator Johnson was the Chairman. We listened to testimony and we saw sheets that were passed out of the red zones in the State of New Hampshire. Those red zones were very apparent in Raymond-Exeter. They were absolutely fire red. I think it's important that we all understand that this is a health issue. This was about taking mercury out of the air, not anything else.

There was an amendment that came out of that committee on Senate Bill 128, and what it said was that the total mercury emissions from all affected sources, burning coal as a fuel, of 50 lbs. per year beginning July 2008. So the amendment that came out of that Senate committee forced Public Service to remove mercury by 2008. Well, that got everybody's attention and it got it pretty quick, because the acceleration that we had in that bill was that all mercury would have been removed by 2011. So that's the true history of the bill, and that's what got the sides together at a table. An environmentalist coming in and saying, that's a great amendment, we're thrilled to death by it.

I think another important issue is that when you talk about history, that there is a committee report on Senate Bill 128. And there were a lot of questions asked and a lot of discussions. I think the most important one, though, is that when you go back, and I'm going to quote, the Conservation Law Foundation came in and they were discussing the legislation. And here's the question:

Senator Gatsas: Thank you, Mr. Chairman. And I quote: "Do you know that a dollar increase is a 15 percent increase on rates? Do you believe that the ratepayers should absorb all of that?"

That was my question to Ms. Gerard.

"Well, right now the law says they would. But I believe the ratepayers have absorbed it in the past and probably should. I will say this, though, after Representative Hennessy's remarks."

So at the time when we heard that it might be a dollar and there was not one question about a $275 million cost. That was an awful lot of money back in 2005, and nobody raised the question about cost.

So the amendment and the legislation do one thing – kind of look, turn back the history of time and look at Seabrook. Delays there cost an awful lot of money to ratepayers throughout the State of New Hampshire. There is more cost and less study of RGGI. We passed a piece of legislation last year called RGGI. There was less study. This bill, when it came through the Senate about removing mercury, took two years to look at. The cost to the ratepayers in the State of New Hampshire with the cost of RGGI is going to be more than what the scrubber costs us. The difference is, that in the RGGI costs there's no CO^2 that's coming out of the air, there's no technology that takes CO^2 out of the air. There is technology to take mercury out of the air and save lives.

I know that people may be a little confused of why I'm standing here and supporting Public Service and their efforts to move forward. I think Gary Long and I have had our discussions in the past about what ratepayers should be paying and what they shouldn't be paying. But there is a time to talk about prudency and that's when the project is done and costs are in. And maybe at that time I say, well wait, the ratepayers shouldn't be paying for all of this, the stockholders should be paying for some of it. But none of us should take a position today to stop the project, until that project is completed and we have an understanding of what the cost is. Because then maybe Gary Long and I will have a difference of opinion. We've done it in the past, but now I stand with him and say that that project needs to be completed because for every home in the Town of Bow, if that project is closed and Public Service closes Merrimack Station, for every home that's assessed $300,000 in the Town of Bow, it's an increase of $800 a year in taxes.

Let's not forget the railroad that delivers the coal. My bet is, that's a primary source of income and they may not be going up that railroad much longer.

So we don't need the PUC to look at it. They've looked at it. As a matter of fact, they probably might take 84 sessions like they did with energy efficiency to come out and tell us how to spend the money. It's probably going to take 84 sessions for them to study what to do with the RGGI money. So, we don't need delays. We don't need the closing of the Merrimack Station. We need this project to move forward. Thank you.

<u>Senator Martha Fuller Clark, D. 24</u>: Thank you, Senator Gatsas. Are there questions from the Committee for Senator Gatsas? Seeing none, I'd like to call upon Senator Letourneau.

<u>Senator Robert J. Letourneau, D. 19</u>: Good morning.

<u>Senator Martha Fuller Clark, D. 24</u>: Good morning.

<u>Senator Robert J. Letourneau, D. 19</u>: Good morning, members of the Committee. Senator Odell, I remember very well serving on that committee when you were Chair, and I remember the bill passing and the discussion that took place. Today is a whole different discussion.

Madam Chairman and members of the Committee, for the record, I'm Bob Letourneau and I represent District 19, the towns of Derry, Hampstead and Windham. I believe this legislation poses a great risk to the residents of my district at a time we can least afford it. As you may know, the electric market reliability, ability has been a concern of mine throughout my tenure in the Legislature. That said, I have admired the way the Legislature, Bm

regardless of political party or ideology, has been able to move New Hampshire forward on energy issues without creating undue risk for our state. While other states have rushed forward with untested policies or ideas, they have many times resulted in drastic results and costs. We have remained steady, determined and cautious in our movement forward.

I believe Senate Bill 152 will take New Hampshire down a new and risky path, where the foundation of our energy infrastructure is left exposed and unstable in a way to force our state in a new and untested and unreliable direction. While the stated purpose of this bill seems harmless, in reality it would create a scenario that will create greater costs for New Hampshire ratepayers, less energy security for our state as a whole, and the elimination of several hundred jobs. I supported creation of renewable energy because I want to see New Hampshire and the United States more reliant on domestic energy sources.

However, as leaders of New Hampshire we need to be honest about the challenges and hurdles that confront the development of renewable energy in our state. Many of the same challenges that confront fossil fuel generation also confront biomass, wind, hydro, solar. Some of the same interests here today opposed to the installation of environmental upgrades at the Merrimack Station are also opposed to the construction of a wind farm in northern New Hampshire. Political, environmental and financial, geographical hurdles all stand in the way of renewable energy.

I have brought along several copies of a column in the Wall Street Journal last week on the development of renewable energy in this country, and you have it there in my testimony. And while there were many issues raised in this piece, the one thing that struck me was the statement that we are tearing down more hydroelectric generation than we are building. Two years ago, this committee had considerable debate over a bill that I brought forward to allow a regulated utility to build one renewable energy project in the North Country. At the time, we were told that a tremendous progress, an opportunity that was happening in that part of that state, and that we should not allow a regulated utility to upset the great progress of the merchant developers - Tamarax' Groveton biomass project, Noble's wind farm, clean energy development, Berlin's biomass project and Laidlaw's Berlin biomass project. There are a variety of reasons why these projects have either died or moved at a very slow pace. But the bottom line is, we have not seen the boom in renewable energy that was predicted four years ago or even two years ago. While the ISO New England lineup may be filled with projects, how many of these projects will actually get built? One in 25? One in 15? Generally, the odds are not that good.

I also want to talk just a little bit about cost. For anyone who deals with construction, the idea that costs have escalated tremendously over the past two years should not be a big surprise. In my capacity as Chair of the Transportation Committee, the issue of construction costs has driven our policy development for the past two years. For example, in 2006 a ton of liquid asphalt cost $250. Last summer, that cost had risen to approximately $850 a ton. Cost increase for steel, concrete, gravel and labor are all well known. In the light of these cost increases, the bipartisan approach that we have taken is to make sure that the foundation of our transportation infrastructure is maintained and secure. I would suggest to you making sure that our state's primary base load power plants remain stable, secure and viable. It is the best way that we can protect our energy infrastructure during these difficult times, as well as position our state for economic growth into the future.

We should also view the cost of the environmental upgrades at Merrimack Station in the light of other energy projects that are happening in New Hampshire. Consider that we are talking about spending $450 million to ensure a 440 watt, megawatt base plant that runs 24/7; remains secure, viable and reduces its environmental impact. In the North Country, developers are talking about spending $250 million on an intermittent wind project that will produce one-tenth the electrical output of the Merrimack Station. Increases in construction costs are impacting all aspects of construction, even renewable power development. Again, I am in support of renewable energy, and I want to work towards a renewable future in New Hampshire. But those of us in the Legislature need to be realistic about where we are today, the cost of achieving a cleaner future and the hurdles that stand in our way. And I'm sure you will hear from countless experts today what our energy future holds. And I can tell you from my expert opinion, and that was gained from unfortunately from age, is that nobody knows what the future will hold. We don't know what the costs will be, what regulations will be enacted, what new technologies will be developed and I don't know where we will be next year, needless to say, that we will be in 10 years , or where we'll be in 10 years. When it comes to energy, all we can do is try to expose our constituents to as little risk as possible as we progress forward. And we can do that by defeating Senate Bill 152.

Last, but most importantly, we have recently learned that this bill would jeopardize up to 1,200 jobs in New Hampshire, as evidenced by the hearing here today. Considering the economy and almost seven percent unemployment rate, this is exactly the wrong bill at a time when New Hampshire is facing the highest unemployment rate in 15 years, and I respectfully urge the Committee to find Senate Bill 152 inexpedient to legislate. Thank you.

Please see Attachment #1, Senator Robert Letourneau's testimony.

Senator Martha Fuller Clark, D. 24: Thank you, Senator Letourneau. Are there questions from the Committee for Senator Letourneau? Seeing none, I'd like to call upon Representative Pat Long.

Representative Pat Long: Thank you, Madam Chair, honorable Senators. First, I'd like to publicly thank Public Service Company of New Hampshire. Not for jobs, not for good jobs, but for family sustaining jobs, family sustaining wages, family dignified healthcare in pride and independence with engineers. Not to mention the trainings that are involved with the agreement that they have made with the contractors.

I'm not going to reiterate what has already been said. However, I do have concerns when I read, when I read of reasonable anticipated environmental compliance costs. Reasonable is a tough word. When I read of the investigation shall be completed as expeditiously as possible but give the report within 90 days.

My expertise here today is not on, is not on the energy, energy field. My expertise is on jobs. And I'm not sure if you could put yourself in a position where, for six or seven months, you've been collecting unemployment and then in these tax times, you're looking at paying your taxes on this unemployment. Obviously, you're looking at families that are taking three to four weeks of that unemployment pay to pay their taxes on. By no means, I want you to think that my main focus is on jobs and jobs alone.

However, in this economy, on March 13, 2009, when I have an opportunity, when I have an opportunity to, when I have a choice that I have to make or my constituents have to make, with several of them are here, whether they want to plant a tree or whether they want a job, today I would say that they would like a job. That doesn't demise, that doesn't diminish them as to wanting clean air. The fact is, the reality is, their desperation is for work in these times, and with that I'll let you know that I'm opposed to this Senate bill and I'm sure that you'll do your due diligence in listening to the testimony and execing this bill out as ITL. I thank you very much for your time.

Senator Martha Fuller Clark, D. 24: Thank you very much, Representative Long. Are there questions for the Representative? Seeing none, I'd like to call upon Representative Chris Hamm.

Representative Christine Hamm: Thank you, Madam Chair, and members of the Committee. For the record, I am Christine Hamm and I represent Merrimack District 4, the towns of Hopkinton, Warner and Webster. And I'm here today to ask for your support for Senate Bill 152, which was drafted in an attempt to adhere to the conditions established three years ago with the passage of HB 1673. That bill's slate of sponsors ran the gamut from those with pragmatic business interests to visionary environmentalists, and was hailed at its passage as a bipartisan effort towards reducing mercury emissions in the State of New Hampshire. As a House member, I voted for HB 1673 because I thought it was a necessary step forward. It had required negotiation and compromise. It promised to reduce mercury emissions throughout the state, most significantly at Merrimack Station in Bow, the largest single source of mercury emissions in this state.

Today, three years later, I come to you because I believe that the expectations we had for this bill have changed and that we're now in a different place. In the text of HB 1673, part V, the bill notes that the installation of scrubber technology will not only reduce mercury emissions significantly, but will do so with reasonable costs to consumers. Although the phrase "reasonable costs to consumers" may sound amorphous, for those involved, including the members, some of the members of this Committee, it did in fact have a specific number attached to it. We know this from a letter, which I can provide to the Committee, from Michael P. Nolan, then the Commissioner of the Department of Environmental Sciences, to Senator Bob Odell, then the Chairman of this Committee. That letter, dated April 11, 2006, states: "Based on data shared by PSNH, the total capital cost for this full redesign will not exceed $250,000,000 in 2013 dollars, or $197,000,000 in 2005 dollars, a cost that will be fully mitigated by the savings in SO^2 emission allowances. Commissioner Nolan sent this same letter to Representative Larry Ross, who was the Chairman of the House Committee on Energy, on Science, Technology and Energy, and that letter was dated January 12, 2006.

Today, when the $197,000,000 2005 figure has already jumped to $457,000,000 in 2009 dollars, it's clear that the original expectation of $250,000,000 in 2013 dollars is beyond reach. $250,000,000 is a big number, and so is $457,000,000. It's a little taxing for us mere mortals to comprehend it. So it seems useful to try to put these numbers in context. As members of this Committee know too well, New Hampshire's shortfall for the biennium was recently projected to be $500 million. Yet, as legislators have contemplated what to do about that, taxing our citizens to make up this difference has never seemed a viable option. Why then wouldn't we at least take the time to hesitate before holding our state ratepayers, these same citizens, accountable for a similar sum? Again, to put $457 million in context, this legislator, Legislature has heard from a group of private investors to say they would be willing to invest $450 million into Rockingham Park, making that project the second largest capital investment ever made in this state. Seabrook was the largest. Yet, $450 million is still $7 million shy of the $457 million projected to install filters at Bow to mitigate only part of the emissions from Merrimack Station.

Additionally troubling is the fact that as these costs have risen, the Legislature has remained in the dark. An annual report, filed by Chairwoman Naida Kaen of the House Science and Technology Committee on behalf of the Electric Utility Restructuring Legislative Oversight Committee, notes that at the Committee's June 18, 2008 meeting, "There was no cost information provided to indicate a significant departure from the projections made in 2006." Again, I can provide this to you. PSNH reported the project costs would be updated with a review of major equipment bids. Despite the cost increase announced six weeks later on August 1, 2008, this report filed on November 1st of that year does not contain the update.

Further, it is important that this committee consider that there has been no review of this cost increase by any state agency. PSNH says that the Public Utilities Commission will review the cost in an after the fact prudency review. But how prudent is that? Why not now instead of later, when it will be too late, too expensive to change course? With no cap on costs, we have to wonder, at what point do we reach our limit? How much is too much to spend to rejigger a 40 year old coal plant at the end of its life span? Is nearly half a billion dollars the best use of anybody's money to produce 430 megawatts of electricity?

In September of last year, similar questions were brought to the PUC, but it concluded it did not have the authority to determine whether the scrubber project is in the public interest, finding that the Legislature had already made that decision by passing HB 1673. This legislation is being put forward to enable the PUC to go forward with that analysis.. As I said earlier, HB 1673 was a major step forward for its time. But now the decision this Committee makes on whether or not PSNH should go on with installing scrubbers that currently cost 83 percent more than anticipated and whose final cost is yet to be determined, will be key to whether that step forward proceeds down the right path.

We live in New Hampshire, famous for Robert Frost's crossroads in the woods. I believe New Hampshire is now at an energy crossroads, at a new place in our understanding of the importance of our energy sources. Since 2006, not only the cost but also technologies have changed, and so have the political realities in the regulatory landscape. We now understand that there are other less expensive alternatives, such as activated carbon injection, that could address these emissions less expensively. We also understand that we must address other emissions, including CO^2 emissions. It appears likely that the new administration plans to have a carbon program in place by 2012. In addition, the EPA will likely introduce new mercury rules, which could mean that the emissions reduction provided by this new scrubber will not adequately comply with EPA standards. As we've heard in testimony on a related bill in the House, that would mean additional controls and additional costs for ratepayers.

To go back to HB 1673, I draw your attention to part VI, which notes that the installation of such technology is in the public interests of the citizens of New Hampshire and the customers of the affected sources. Again, I believe that when this was passed, that public interest was served. But now that the balance between cost and results has been skewed and it is clear that additional improvements will have to be made at additional cost, we have to wonder whether or not going forward with the installation remains in the public interest, and that is what we want the PUC to review.

As the bill states, as legislators our first concern should be the citizens of New Hampshire and PSNH's customers. I believe this Legislature, but first this Committee, needs to consider whether the agreement forged in HB 1673 is still in the best interests of New Hampshire's citizens and PSNH's ratepayers. The sponsors of this bill are not alone in thinking it is not. Currently there are more than a dozen pending dockets, cases and permits relating to Merrimack Station, ranging from a Title V permit under the Federal Clean Air Act; to a case before the New Hampshire Supreme Court filed by the commercial ratepayers group; to guidance memorandum from the EPA requiring PSNH to apply maximum achievable control technology retroactively to 2005, something that the scrubbers as currently configured do not achieve; to another case filed jointly by the Conservation Law Foundation and Freedom Energy, questioning the legality of the new turbine which increased the output of the plant and was installed without DES permits in April 2008; to a PUC order requiring a study and economic analysis of retirement for any unit in which the alternative is the investment of significant funds to meet new emissions standards and/or enhance or maintain plant performance; to the Obama Administration's announcement of a new federal CO^2 program; to a pending report from the Governor's Climate Change Task Force.

Clearly, in the three years since HB 1673 was passed, the ground has shifted and clearly there are many important questions to be answered. Clearly our constituents, the PSNH ratepayers, deserve the same kind of cost benefit analysis for an expenditure of this magnitude that PSNH would undertake for its shareholders. Four years from now, or 15 years from now, as energy

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rates rise into the stratosphere, we simply cannot tell our constituents that although we knew of these coming federal changes, the pending issues with the plant and the 83 percent cost increase that has not yet been reviewed, we did not review our options before going forward. No one is talking about doing nothing. Clearly, it is our job to make certain that the ratepayers of this state are protected, at the same time ensuring that our energy sources have the smallest possible environmental impact.

I urge this Committee to take these responsibilities seriously. Recently, representatives from PSNH reminded us that New Hampshire led the nation by passing the Clean Power Act in 2001. Let's not see that tradition, one that all of us have the right to be proud of, go up in smoke. Thank you very much.

Senator Martha Fuller Clark, D. 24: Thank you very much, Representative Hamm. Are there questions from the Committee? Senator Lasky.

Representative Hamm: Good morning.

Senator Bette R. Lasky, D. 13: We have before us an amendment which replaces the bill, and I forgot to ask Senator Janeway about it. But I wondered if you could point out the significant differences in the amendment, as we were just given it this morning?

Representative Hamm: You should ask Senator Janeway rather than me. Okay. I was involved a little bit at the beginning of this and then he, I have read the amendment as he's shown it to me, but I'm not the one to really talk about the differences.

Senator Bette R. Lasky, D. 13: Thank you.

Senator Martha Fuller Clark, D. 24: Senator Janeway, would you be able to answer that?

Senator Harold Janeway, D. 7: I can't, without the prior bill, give you precise. There were changes that were designed to make sure that the PUC wasn't forced into the longer, sort of more formal process, and other than that, really the thrust of it remains the same. I'll see if I can get for you. Actually there were a series of modest tinkers that were made as we moved along. I'll try to get a full set so you can see how that went, if that's alright.

Senator Martha Fuller Clark, D. 24: I guess I'm elected. Senator Lasky, does that answer your question?

Senator Bette R. Lasky, D. 13: Certainly. Thank you, Senator Janeway.

Senator Martha Fuller Clark, D. 24: Senator Janeway, I do have a question for you, which was raised by Senator Gatsas. Is once, if this bill were to go forward, once this study was finalized, how do you believe that it would be useful to the Legislature and to all of the citizens of New Hampshire and our constituents?

Senator Harold Janeway, D. 7: Well, my first answer to that is that I think we all need more information and so that shining a light on the issue would be helpful to everybody, whether it goes forward or not. So I think there is, if you will, an educational process that would be part of the outcome here. I can't predict exactly what follow-up measures would take place. It may be something that would come forward in the subsequent sessions, but I don't see how there would be anything immediate or dramatic.

Senator Martha Fuller Clark, D. 24: Follow-up. I know that one of the concerns of many of the people here today are that this bill is a thinly veiled attempt to close down the scrubber. Would you be able to speak to that? And what, I guess that's my question to you.

Senator Harold Janeway, D. 7: I certainly don't see it that way and that wasn't the intent. We're looking for more insight, more information, more perspective. I think there, I'm pretty sure there are people who support this bill who would like to see that happen. I'm not one of them. The sponsors aren't in that position, so it's somewhat, I'm inclined to say, a way of trying to trash it when that is not the intent.

Senator Martha Fuller Clark, D. 24: Thank you. Additional questions?

Senator Bob Odell, D. 8: Thank you, Madam Chair. Representative Hamm (INAUDIBLE), I think Representative, Representative Hamm mentioned this issue of prudent cost. When does this, if this is a, I'm trying to get from a very simple example, the 90 day process, if I'm understanding...

Senator Harold Janeway, D. 7: Correct.

Senator Bob Odell, D. 8: ...but as you go through this prudent cost aspect of this, how do you, what happens if you say it's a little imprudent or not a little imprudent? Where are we at that point, and I do go back to Senator Gatsas as a follow-up to the Chair, so then what do we do when September, October, November of this year, with whatever we have as far as information? How does that ennoble (sic) this body, the Legislature, to do something?

Senator Harold Janeway, D. 7: Well, I think it's so much, we're all having trouble, it's not so much focused on the costs of the scrubber project, it's going to be what it's going to be. It's more, what does the commitment to that scrubber imply in terms of future costs if other measures that I referred to as possible, say the EPA decides that the mercury limit should be 90 percent or 95 percent instead of 80 percent? Or if water temperatures require, and other such things, require additional investments? So it's looking beyond the, the hope is that the study will look at the possibilities beyond the scrubber that would lead to substantially higher costs. And you'll hear testimony on that, I think, from others today.

Senator Bob Odell, D. 8: In a practical way, what I've heard from some today is quite speculative about what EPA will do, what this organization is going to do, what the standards are going to be due (sic), what the changes are going to be due (sic). Let's say we go 90 days and we have this study parallel to activity at the site, and then something changes on the 93rd day after the study is going on. And this seems to me as if it's always a moving target, there's going to be dramatic changes as we go forward. I think no one's learned quicker than President Obama that things don't happen on his schedule. There's Congress and there's a lot of other factors at play here, but somebody has picked an arbitrary 90 day period, if I'm correct, to assess this, and I just don't know how you put a deadline on a $500 million project and say okay, at, in 90 days we're going to be able to tell you that here's some plausible, I think that's the term here, plausible situations that might evolve in the future. And I don't know how far out the future is? Is that one year, two years, twenty-five years? And I guess that's the question.

Senator Harold Janeway, D. 7: Yeah.

Senator Bob Odell, D. 8: How does this really fit in with the reality of a $450 million project?

Senator Harold Janeway, D. 7: Well, I agree nothing is certain in this life or in this world. But our concern is that there hasn't been any attempt at this point to look at those other potential things, and the EPA, for instance, has already made some, taken some action that points to, you know, stricter standards. There are, it's far less likely that, most of, a number of them relate to new coal plants rather than existing coal plants, but there are, the direction in which the EPA is moving is pretty clear. And 90 days just seemed like enough time to assess what we know now, as opposed to, and look at that, compared to what was known when your bill, which I fully supported from the outside back in '06, did. So it's an update, let's just look at this and be sure we've thought it through.

Senator Martha Fuller Clark, D. 24: Senator Lasky. Thank you.

Senator Bette R. Lasky, D. 13: Thank you, Madam Chair. Senator Janeway, as I see in the amendment and as I've seen all along in looking at this project, is one of the major questions I believe that's still out there, is the projected costs of supplying customers with purchases in the wholesale power market. And that is one of the things that you want to analyze. Do you have any projected figures as to what that might be now, as opposed to, you know, going ahead with the scrubber?

Senator Harold Janeway, D. 7: Thank you for the question. There are current costs in the purchase power market which others will be able to speak to. They've come down quite substantially with, in line with the surplus of capacity that has developed. ISO New England, which is the outfit that collects all the data on New England's power pool, has estimated that there are, there is the equivalent of perhaps seven Merrimack Stations surplus capacity right now. And even future, projected out, I think three years or so, so that has pushed down the price, but others who you will hear from later can provide more detail on that.

Senator Bette R. Lasky, D. 13: Thank you, I will ask them. Thank you.

Senator Martha Fuller Clark, D. 24: Thank you. Other questions? Let us move forward. Representative Walz.

Representative Mary Beth Walz: Thank you, Madam Chair.

Senator Martha Fuller Clark, D. 24: INAUDIBLE

Representative Walz: I will not, although I do intend to answer some of the inaccurate information that my predecessor had stated. So to that end, I would like to thank the Committee. I am Representative Mary Beth Walz. I represent Merrimack County District 13, which includes the towns of Bow and Dunbarton, so the plant is in my district.

And with that, I might add that this is a plant I've been familiar with since well before I was elected to the Legislature. I probably had my first tour of the plant about 15 or 16 years ago, and over time I have followed that plant and come to understand a lot about it, including how the darn thing runs. And so I'm more than a little familiar with the plant and how it fits into PSNH's plan for power in New England. So I do not come at this as green as perhaps some of my fellow representatives.

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Well, I'd like to start off and say that I am quite alarmed by the fact that we have this bill before us at all. I find this incredibly disingenuous of the environmentalists to be bringing this bill forward at this time. I, too, remember, as was testified before, that three years ago this bill was touted as a huge success, because we brought the environmentalists, we brought the company and we brought the Legislature to the table and we all came to an agreement. We all looked at all those factors and came to this agreement that allowed the company to move forward at what was going to be great expense to them, but it also cleaned up the air of mercury. This plant's going to take 85 percent of the mercury out of the air. It's twice as good as any carbon injection system, that has been referenced earlier. I know Representative Hamm suggested carbon injection. This reduces twice the mercury any carbon injection system can. The company worked with EPA on carbon injection systems and this is the best way to get mercury out of the air. So this was a great plan that moved this forward after carbon injection systems, and said this is the way that we can get the most mercury out of the air.

So, then I looked at this bill, and this bill, the original bill said what is in the best interests of the retail customers? So I looked at the bill initially in that respect, and we know that we need reliable, economical base load power in this state. And I heard testimony up here from Senator Janeway before, that we have an excess of power in this state. I sat there stunned! Stunned! Does he understand this winter how close we came to not meeting our load need? There are jet engines at the Merrimack power plant. I didn't know this until recently. There are jet engines that have been there since the 1960s, and when the plant itself, and when all the plants that are fired up in New England can't meet the base load, they turn those jet engines on, and somehow beyond my knowledge, they can generate electricity using those jet engines. This winter, they were running those jet engines! We didn't have enough power on some of those cold mornings to meet the power needs of New England. They had to turn the jet engines on! Where does (inaudible (1:01:20) we've got seven times the load of Merrimack excess in New England comes is well beyond me, because the experience of this very winter contradicts that.

One thing that the proponents of this bill keep talking about is that we need renewables, and they talk about wind and they talk about solar. What we need here is base load power. You need power that you can call up when you need it and have constantly running. Renewable power, like wind and solar, is intermittent power. You can't just call on it, you're the victim of the weather. Does the wind blow, does the sun shine? And what happens at night? When you replace the Merrimack Station, which we are going to have to do, you're going to have to replace it with some sort of long term viable base load power, not intermittent power. And that difference seems to have been lost on the people talking about this bill. But it's an important distinction. You can't replace base load power with intermittent power.

They also talk about the economy here. We all have heard endlessly about, because of the increased cost here, about how this needs to be looked at. The reality is, as I stand here today, PSNH has the cheapest utility rates of any utility in all of New England, the cheapest rates, not just in New Hampshire —in all of New England. If you take and you put that scrubber on at $250 million, they're still the cheapest power. If you take it and you put it on at $450 million, maybe we're not the cheapest anymore, but we are still below market. And the power coming out of the Bow power plant is still below market. So if you shut down that plant and you try and replace that power at market rate, my understanding is it's going cost you, today, $30 million a year to replace it at market rates. That's more than it would cost just to pull that power out of the plant with the scrubbers.

Now, I can stand here and do that as a back of the envelope computation. You don't need a 90 day study from the PUC to run that simple calculation. So I would suggest that you need to be looking at that factor as well.

Now if, it's not clear me that this study calls for delay. But if there is a delay due to this study, if you take a three month delay, because of the work season here, because of our winters, a three month delay means a nine to twelve month delay in the construction on that plant. What does a nine to twelve month delay do? Well, for one thing, we get all that extra time of mercury spewing in the air. I am troubled and confused with how the environmentalists think it's a good thing to keep the mercury spewing in the air while we slow down doing this.

Secondly, it increases the cost even more. So they're coming at you and are screaming about the cost of this plant, but what they're proposing is going to increase the cost even more. Why would we want to take a course of action that's going to make the scrubber even more expensive than what the market costs have made it already?

Now, what will the study show? I know you asked Senator Harold Janeway that. That was a really mushy answer, from my point of view. What are they going to do with that information? Even if you have the study, what do you do with the information? You got two choices: either you go forward or you shut down the plant. Shutting down the plant doesn't seem like a viable alternative. We've got, I think, about $200 or $250 million already invested in the scrubber which PSNH, under current law, would be allowed to recover. And I think if you didn't allow them to recover, it would be unconstitutional.

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So we're already into this for a couple hundred million dollars. So we're going to stop? We're not going to, we're going to let them recover the $200 million because you have to, and then do what? Then start all over with a new plant that's likely to cost in excess of $500 million? I mean, I don't understand where we're going to go with this information.

We hear things have been changed. I have not heard from any of the proponents any new technology here. What has changed? In a short period of time, what has changed? There is no major earth shattering thing going on. We don't hear changes going on around the country. We don't hear power plants across the country changing what they're doing and putting in some newfound technology. This is the state of the art technology. So the costs have gone up. That happens. It happens on all kinds of things, you know. We'll deal with it and that's what the prudence review is there for.

Businesses need business certainty. Who are we as the Legislature to come in there and say, well, two years ago we thought this was a great idea so we passed this bill and we told you, PSNH, you have to do this and now you've spent a couple hundred million dollars on it. But, now we've changed our mind. What businesses want to stay here, when we've got a legislature like this that two years later is coming back and changing the rules of the game? You can't come back and do that to businesses. That is hardly a business friendly approach to anything in this state.

So I also looked at the amendment on this, which I saw a few minutes ago sitting down here. I had not seen it until somebody referenced it. I didn't even know there was an amendment. I've only had a moment to review the amendment, but if I look at the amendment, what you're doing is putting in a pre-instruction (sic) prudence review. So basically you're telling the Commission ahead of time what they have to do in this prudence review and you're telling the company ahead of time what you have to do, kind of regardless of the realities and regardless of the cost. I don't know how you can do that, and I don't know that that's a good approach to policy, particularly when we have a prudence review in state. Representative Hamm referenced that the prudence review comes too late to do anything. That's malarkey! The prudence review is there to make sure that the company's been honest in what they do, and if they're not honest, then the prudence review, under the prudence review the PUC has an obligation to disallow inappropriate costs. It's not discretionary, it's an obligation, and if they don't disallow it, you can bet the Consumer Advocate's going to take them to court and fight them for not disallowing inappropriate costs. So the prudence review that's in place now is more than adequate to deal with the increased costs of this plant.

So let's look at the situation. I maintain it's in the best interests of New Hampshire to go forward with this scrubber in a timely fashion. It's the most environmentally friendly approach, okay. We stop the mercury. We are, it's the least harmful to the ratepayers. In the long run, it's going to get power at the cheapest rate and it's going to get the mercury out of the air at the cheapest rate. And consistent with the first bill, I pulled the state energy policy that it references, and I've got to tell you, it's a home run. It's consistent with the state energy policy. I looked at this and I was frankly confused why the proponents bothered putting it in the bill, because this scrubber's so clearly consistent with the state energy policy.

So I would suggest that we as a legislator (sic) have an obligation here to approve this scrubber, then to look at ways we're going to meet our renewable goals that we have to do. We're going to look at fixing the transmission system in the North Country and coming down from the North Country, so they can put plants in. We're going to look at ways to put renewables out there. We're going to develop other forms of generation. But we can't do that now and still meet the power needs of the state. So let's put the scrubber in place, meet the power needs of the state, and use that time that the scrubber buys us in extending the safe life of the plant, to do what we need to do to put reliable, safe, environmentally friendly power in state and the transmission to carry that power to our ratepayers. Thank you.

Senator Martha Fuller Clark, D. 24: Are there questions for the Representative? Seeing none, INAUDIBLE

Representative Walz: Thank you.

Senator Martha Fuller Clark, D. 24: INAUDIBLE Are there any other representatives who want INAUDIBLE

Representative Frank Kotowski: Thank you, Senator Clark; Chairman, esteemed members of this panel. I stand here for the first time on this floor as a Representative, scared to death. My name is Frank Kotowski, District 9 in Hooksett. I stand here scared to death only for having to stand before this mike for the first time in 19 years. I worked for Public Service Company for 33 years of my life. I've not been through the front doors of Public Service Company for the last 18 years to speak with anyone who works there. I want you to know that. I rise here because I saw during my career with Public Service Company exactly what happens when perhaps well meaning people try to impress upon all of us the minority view. I believe that this project is terribly important to the future of the folks who live in my town who work at the Bow power plant, and I believe that I would be wrong if I didn't stand here and tell you that.

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We all know what happened several years ago, at a time when Renny Cushing and myself and others debated these very issues. We took a project then that would have given New Hampshire true energy independence. That was the Seabrook project, I'm not afraid to say it. The company at the time had projected, if you recall, the cost of that plant to be $998 million for two, 1150 megawatt power plants, base load plants, such as the previous speaker spoke about the need for. And they delayed through these very same kinds of tactics that are being used right now on this bill. They delayed that project to a point where it brought a very good utility to its knees, bankrupted that utility, caused it to cancel one half of the project. Which ultimately, by the way, Florida Light and Power eventually, after having acquired it from Northeast Utilities, who bailed this good company out. I submit to you that you're going to really look carefully at this clearly but thinly veiled attempt to delay this project so that the costs continue to rise, for whatever purposes they have in mind.

Thank you very much.

Please see Attachment #2, Representative Frank Kotowski's testimony.

Senator Martha Fuller Clark, D. 24: Thank you very much. Are there questions for the Representative? Seeing none, are there any other representatives who would like to speak? Seeing none, I would like to call Gary Long.

Mr. Gary Long: Thank you, Madam Chairman, for the opportunity to speak. Thank you, Senators, for the opportunity to speak with you today. I'm Gary Long, I'm the President of Public Service Company of New Hampshire. After I give my remarks, there is another gentleman here named Gary Fortier, who's the Chief Operating Officer of a company called Power Advocates, and he is an expert in scrubber costs and he can show you how these scrubber costs fit in with the rest of the industry, and I hope put your mind to rest on this matter of scrubber costs, and I think he can show you how reasonable they are. And I'll have more to say about that also.

Now, I've been in this business for 33 years. I have spent a considerable amount of time and thought on this, and all the issues that we face. My career started about the time of the Arab oil embargo. I don't know if any of you remember those days and the disruption that that created for our society. Since that time, I've seen fuel prices go up, I've seen fuel prices go down. I've seen oil and gas prices go up and down and they all have gone on a steady upward trend. I've seen the rise and fall of nuclear power in this area.

There still are nuclear power plants, but there's far less now than there was 10 or 15 years ago. I've seen the emergence of energy efficiency as a way of doing business. I've seen a multitude of policies come out of both state and federal government, radical and very different policies in all those times. And I've seen forecast after forecast of what the future yields, what those policies might be, what those fuel costs might be, what the future price of power might be. And I can tell you every one of them's wrong.

So when you're dealing in a situation like that, and certainly we've all experienced that just recently, I will tell you that people did not project, experts that you pay money to, did not project that oil prices would go up to $145 a barrel. But when it was there, experts were telling us that it will be $200 a barrel. Three months later, it was $40 a barrel. Now, I'm not blaming anybody for that because nobody can really forecast the future. If they did, we wouldn't be in a recession. If they did, our 401(k) and our investment, our retirement programs wouldn't have lost 30, 40, 50 percent. We would have taken different actions if we had that perfect picture of the future. Yet when I hear someone say let's do a study, let's spend a million dollars, let's spend two million dollars. And wherever you stand on the study, I can guarantee you, whatever version of the future that that study tells you, you're got to be really careful about believing it and acting on it.

So what do you do in a situation where the rules are changing? What do you do in a situation where the energy costs are changing and policies are changing? As I said, I've lived that for 33 years, and there are ways to deal with it and we're dealing with it very effectively. There's some principles that we follow that have worked and been time proven. One is, you own assets. When you own physical assets, then you control your own fate, and you're not subject to the ups and downs and vagaries of the market. And one of the greatest decisions that this Legislature did was to say, PSNH you should keep your existing assets and generation. That has been hundreds of millions of dollars of value to our customers.

Another thing that people like me do, to ensure that customers are protected, is you have fuel diversity. We're learned time and time again, you cannot depend on one fuel source. As I say, the recent history has certainly showed what would happen if you relied on one fuel source. So the way you address that is to have fuel diversity. In fact, it's a state policy. In fact, it's a regional policy that we should have fuel diversity. PSNH has the most fuel diverse power supply mix in all of New England. We have more renewable power, percentage wise, than any other company in New England. It's not enough. We have coal, we have oil, we have gas, we have hydroelectric power, we have wood power. We buy a small amount of power from Vermont Yankee, there's a little bit of nuclear power. And recently we added to our portfolio wind power, from the Lempster, the first wind park, energy park in New Hampshire, and we were part of that and helped make that happen.

So when people talk about Merrimack Station, we currently get very interested in that, and I should have started out by telling you we're strongly opposed to Senate Bill 152, in case you didn't know. Strongly opposed and we're asking every senator to vote against it. It is not a simple, it is not a simple study bill. It is a bill that is designed and geared for closing down Merrimack Station.

Now Merrimack Station provides fuel security, fuel diversity to our mix, it is our most economic power plant, and we have embarked on a multi-year plan to make it one of the cleanest coal plants in the nation. Not only does it do that for us and for our customers from an energy perspective, it also provides huge economic benefit to our state and to our community. You'll hear today about what its impact is on rail service. We are the anchor of rail between Concord, Manchester and Nashua, for those of you who are interested in commuter rail. We're one of those. You need Merrimack Station to help provide the platform for that, and you'll hear more about that today.

So we are, we are obviously strongly opposed and I just want to get into some of the things that are affected. When we look at this bill, and it's been said by others, but you either have a scrubber or you don't. The bill uses the word alternative. The alternative to having the scrubber is not having the scrubber. I don't think there's anybody in this room today who would say, I advocate running that power plant in the future without a scrubber, including Public Service Company. We're way beyond that. We're committed to putting the scrubber in that power plant and that's what everybody wants and that's what we want.

So the alternative to putting the scrubber in is not putting the scrubber in. And if you don't have a scrubber, you don't have a power plant. And that's why we feel so strongly that is really a bill about closing the plant, and Senator Janeway admitted that, although he himself does not claim to want to shut the power plant. He admits that supporters of this bill want to shut the power plant. So I think you need to look at it in those contexts and that's why you should vote against it.

As I said, Merrimack Station provides an incredible economic benefit and a foundation for rail and other things in this state, but more importantly, it provides hundreds of jobs. It provides hundreds of jobs for our own employees. It provides hundreds of indirect jobs for services that are provided to the plant. And right now it's going to provide hundreds of new construction jobs. As one of the reports said, this is not a shovel ready project, this is a shovel in the ground project. Employment can start immediately. We have the permits, we're ready to go.

You have a package in front of you, and I'm going to be referring to some of those pages. I won't talk long on each one of them, but just so you can look at later. But one of the things I want to address in the course of talking to you today is some of the myths that have been spread recently in this regard. One of the thoughts that you hear up there is that, gee, if we don't spend money on the scrubber, we have money to spend somewhere else. That's a total myth. We can spend money on a scrubber and we can spend money on energy efficiency, and we can spend money on renewables - we the state, we PSNH. They're not mutually exclusive. It's not an either/or. So I'd really like to put to rest in your mind the idea that if you say no scrubber, that somehow that frees up money. It doesn't. We're capable as a company to do all those things. They're not mutually exclusive.

Transcriber's note: Due to the volume of materials submitted by Public Service of New Hampshire, those documents are not attached to this transcript, but are available in the original bill file.

Another myth that's out there, is this is an old plant. Now if this was a car, I would agree with you, it's an old plant. It's an old car. But it's not an old plant, it's much newer than you think and I'll show you. I'll show you today in areas that it is new, far newer. And when you talk about infrastructure, old has a different kind of meaning than if you talk about a consumable good. You hear people alleging that these costs, the costs are going up. That $457 million, the costs are going to go up. I'll explain to you today something about construction projects and construction management. Hopefully we'll put that to rest, too. The costs aren't going to go up. If anything, the costs will go down, and it's the way that we execute projects like this is to avoid the costs from going up. And we can talk about that some more, too. So you can think about the 457 as a very good number. If anything, we're already taken steps to make it lower, barring a delay or something else that would add to the costs.

You also hear people on the myth that, gee, for some reason, we're not, won't be able to comply with federal regulations. Well first of all, they don't know what those federal regulations are, and secondly, they can't predict them anymore than anybody else, because we don't decide what those are and no individual decides that. So at best it would be speculative. But the way I look at this is putting a scrubber in and all the other things that we've done over the last 15 years, puts us well ahead of the rest of the nation. As the President of the company, I am so confident that we can comply with any federal law on carbon or mercury and that this project is the right time and

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the right place to do that. I am not concerned in the least about changes in federal law. In fact, I welcome them. I hope that there is federal law, because I think there needs to be national policy on things like carbon. There needs to be national policy on things like mercury emissions. It just happens that New Hampshire is well ahead, well ahead of all that, and I compliment the Legislature and environmental groups in the state, regulators, all who worked to make this happen. For me as the President of the company, that puts us in a very good position, that I don't have to worry about federal regulations like some other utilities were, because we're already well ahead of the curve. So I think that's a myth or scare tactic that you should dismiss.

The other one that I think people didn't realize it or understand it, say well, the project hasn't started yet. I can tell you this project is almost in its fourth year. The project started the day you passed the law that said it was in the public interest. The project started the day you said, you ordered this, you put in the law, put in the scrubber. It started then and like all major construction projects, this is about a six year project. We're about the third year, we're almost in the fourth year of this six year project. The project started a long time ago. What you haven't seen is major construction, and we're right on the edge of starting that. But the project has started, and as mentioned by others, you have to start it, and you have to do your contracting to make things very solid and predictable, and we've done all that. And as you may have seen, we already have contractual commitments where we've spent up to $230 million and there'll be more as the project moves forward.

On page three, I'll do this very quickly, but I think most people understand that Bow operates 24/7. As one of the representatives mentioned, it's a base load plant. It's very reliable. It's running better now than it did when it was first built.

On slide four, you'll see some of the history of the plant. And like I say, some people call it an old plant. Actually, it's a plant that's run better and set records, set its all time plant operating records in the last four years. If it's an old plant, I'd say it's running better than it's ever run, and it's producing more efficient and economic power than it ever has in its history. So to me, that's not a definition of old, that's a definition of well run. If you were in the control room of our power plant, you would see an array of computers and computer screens. And these are things that didn't exist in 1960. They are not old.

Page six here really gets to the policy that you have set out over the last ten years or so, and we're actually very proud of the collaborative efforts that have gone on with the State over this period of time. We've had a history of environmental groups, the company, regulators, legislators, working together and we're very proud of being very progressive in that area, as the state and as the company, and that's why we're so bothered by this bill, which does just the opposite. Instead of collaborating, this is putting people apart.

But if you look at page five, you'll see what we've done, as the state and as the company. We've had major, major improvements in environmental qualities of that plant. It's all because, it started in 2002, others have mentioned this, something called the Clean Power Act. Now we embarked on a path to take care of poor emissions. There's nox, tox, mercury and CO^2. And no one else in the country has ever done this. But we were willing to do it with you, and you were willing to do it with us. And the last two that needed to be addressed were mercury and CO^2. In 2006, through a long collaborative process where we all came together, very substantial votes, majority, large majority, sometimes unanimous votes out of committee, for this mercury bill - supported by the Governor, supported by the Legislature, supported by environmental groups, supported by the business community, supported by PSNH. That's the bill we're talking about today, that's the thing that brought us up today. And so we accomplished what we set out to do.

Back then, you asked PSNH, "Are you willing to put in a scrubber?" And after having that collaboration, we said "Yes, we are." And we do what we say we will do. We keep our word. You looked at us and said yes, as a state we want you to do this. How do you make sure that you do this, PSNH? And we said, well, our word is good, we will do this. You said, no, we're going to write a law and we're going to tell you to do it. And we said, fine, because we're going to do it. So you wrote a law and told us to do it in law. Then the next question is, we really would like to spend sooner, not later. Yes, we'll do it sooner, we'll do it the best we can; we'll execute this as fast as we can and do this as soon as we can. Well, how do we make sure that you do that? Well, you can always put a provision in law, and you did that. You wrote a provision in law that said that PSNH, if you put the scrubber in sooner than the absolute deadline which has been 2012, then you will create a financial benefit to your customers. Not to your investors. You will create a financial benefit to your customers.

Well, we've been working very diligently to do this as soon as possible, to do what you've asked us to do, which is to do it as soon as possible. So we do what we say we're going to do, and we have done what we said we're going to do, and we have done what you asked us to do. And what I'm asking you is to keep your word. What I'm asking you is to abide by the law that you created.

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One page six here, there's another depiction of the accomplishments that we've collected, that we've done together and you will see, this is another reason why it's not an old plant. Since the plant was first installed, we've reduced particulate matter by over 95 percent. We've reduced nitric oxide by 85 percent. And with the scrubber, we've going to reduce mercury by 80, 85 percent, and we're going to reduce sulfur oxides by 90 percent. I think that's something we should all be cheering about and being proud about, and we should all be working to get this project done as soon as possible. That's what we should be doing. That's what PSNH is doing.

What's the status of the project? And as I mentioned earlier, it's on slide 7, if you're following along. I have no concerns about federal regulations, in fact, I welcome them. And that's one of the points of this slide.

One page 8, is a picture, a diagram of Merrimack Station. It gives you an idea of the footprint of that plant and how much has been added to it, and for, have environmental improvement, and what the scrubber will do as far as the footprint. And of course you'll see it's a rather large and substantial physical structure. And of course to do that, you need people, which will create a lot of jobs, a lot of good work. A lot of quality good work, and we're very pleased with the relationships we have with the unions that will help bring that good work to bear on this. And it couldn't be at a better time, in my opinion, in history. Not that we planned this. Of course, nobody wants a recession, but if we're in a recession like this, what better way to get people employed than to have an environmental project that makes a plant cleaner. So we're very, very proud of that, and we'd certainly like your support in getting that done.

Page nine, and again you know, I could talk to you at length about how one manages construction projects, but I know as legislators you may not have experience in that. But this really gets to the point that this project is not just started, it's been going on since 2006, and this is a typical way that you manage major projects, and you can see we've started. We already have, we did the preliminary engineering, we got a project manager, a program manager, who helps bring it all about. We've done the detailed engineering and we've issued major contracts last year, and we're ready to go on the major construction. We've done site preparation already. If you had, as Representative Walz said, she's been to the site many times. If she'd been to it recently, she'd see it looks much different than it was a year ago, because we've done a lot a site preparation in preparation for the permitting and major construction.

This may be a good time to give you an example of how projects are run. We're very, very proud of our wood burning power plant over on the seacoast.

And that, like the scrubber, is a result of your action, as a result of a law that was created in New Hampshire. As soon as you get a finding of public interest, which you have already done, you've given a finding of public interests in this in 2006. We got a finding of public interest on our wood project, I think it was 2004. But until you've got that finding of public interests, you're doing estimates, you're doing rough estimates, and the world changes. And during that period of time, 2004, '05, '06, prices also were going up during that time, and we had the same interests then that we have now, which is to contract in a way that you minimize and you stop and you lock in the prices so that they won't go up. And so we did that. As soon as we got the finding from the Commissioner of public interests, we issued the same sort of contract that we had with the scrubber, which are fixed price contracts. That means they can't go up. And so that project was a $75 million project, and we never, ever exceeded that $75 million throughout the whole construction cycle. In fact, we came in a little bit lower.

That's the same way that we're managing this scrubber project. We issued contracts. We're looking at $457 million, and now, and we're not going to exceed that. And so now we're looking at ways to bring it down, because we have fixed price contracts for all of our major contracts. They've already been issued. And that's the way you run projects and we've been very successful in that, and that's the way we protect customers. That's the way we make sure that customers are protected against escalation. That's why I say it's a myth for people to say the costs are going to be a lot more than that. They're not. If anything, they'll be less.

One page 11, it's a very important one. As I said, nobody can predict the future, but we are, and that's why we define things. And we know what the costs of the scrubber are going to be. We know that. You don't need a study for that, you don't need anyone to project the future. We know that cost, at least we know the maximum. And we know what the impact on rates are, and that's on page 11. You've heard it before. It's about three-tenths of a cent per kilowatt hour. And of course, you have to pay more if you've installed equipment like that. And it's going to cost more to have a cleaner power plant. But we all accept that. We all accepted that in 2006. We all knew that it costs money to have a cleaner power plant, and we're all willing to do that. But it's very competitive, and the plant will continue to be very competitive. You can see on that chart, that I don't want to trivialize point three cents a kilowatt hour, but it's well, well within the variations that you get in fuel costs, and it's well within the market value, the market differential between our plant and the market. So we feel quite comfortable, even though it is a price increase, the plant will continue to be highly competitive in the marketplace. And it gives us certainty.

Page 12, for those of you who are interested in more detailed cost estimates or prices and what a project is all about, there's nine or ten or so different elements of this project that all are contracted for separately and all that add up. So, you know, it's far more than putting in a flue gas, you know, de-sulfurization, there's a whole lot of other supporting and other work that goes with it. So just to give you a little idea.

We have very detailed documents on this. I mean the Public Utilities Commission can and will see all of this stuff. They look at all these project things and they do prudence review and they do a very thorough job. So we're not at all concerned with that, because we think we're doing a great job and we know they will do a very thorough job in reviewing what we did. But we don't have any problem with that. That's done in the normal course of business. That's already provided for under current law.

Senator Martha Fuller Clark, D. 24: Mr. Long, I do have one question for you, as it's going to better be ....

Mr. Long: If it's really pressing. I'd prefer to go through and then answer questions.

Senator Martha Fuller Clark, D. 24: Thank you.

Mr. Long: On page 13, is what some of the rough estimates were in 2005, as compared to 2008. You know, lots of things have gone up, as others have. In fact, everything all around us, all around us, in all the infrastructure projects and construction projects, you see the same sort of thing going on. That's why, when we get into construction projects, we try to lock into the costs as soon as possible, so that we can avoid further increases.

Page 14 just tells you a little bit more about what drives those costs. I think the things that are really interesting, hopefully you will find it interesting, is if you go to page 15, and this is a chart. This is not prepared by Public Service Company, this is prepared by a very renowned firm called Cambridge Energy Research Associates. Okay, we took this directly from their research. And this is just, and this again is not speculation. This is not speculating about the future, this is what actually happened, okay. And so this is what actually happened to power capital costs between 2005 and today, and you can see, you can see that all projects throughout the country were experiencing the same sort of price escalation as we did. So that means that all of our competitors, others had their costs going up too, which means that relative, the whole market went up. So when you see scrubber costs go up, sure they did. But so did everything else and so relative to the market, we're still very good.

And the same sort of thing on page 16, you see iron and steel, cement, and they went up in great amounts from 2005. And of course anybody in the construction business knows that, anybody in the power business knows that. And the same sort of thing, if you go to page 17, copper, nickel, you know increased. They're still all up, very substantial increases. I give this to you only to point out that, you know, obviously a project of this type is very complicated and no one expects you to be experts in project management. Nobody expects you to be experts, but we are, and these are things that really, I think, would indicate to you what drives these costs up and it's not unique to Public Service Company. As I said, Gary Fortier will compare it against other scrubber costs around the nation. You'll see the same sort of thing, that we're very competitive and we're very much in line with what others are experiencing.

And page 18 is a little bit more than that. There's a little more information on the cost differentials that have occurred. And really, you don't need a bill, you don't need legislation to understand this data or to get it. I mean the PUC has access to this data without any law changed, and they certainly will look at it before, as Senator Gatsas says, anything goes in rate. I mean you really should take comfort in that. If they think we did anything wrong, or didn't do anything well, they will certainly let us know; and we will be hearing that one out too. So, I don't, you really don't, there's nothing to do in a future study that will help you understand the costs of the scrubber.

And our whole approach, on page 19 there, and it's been very, very successful and our award winning wood plant, it's gotten, five, six, seven awards, national, international, construction awards, engineering awards. We're using those same practices that we used in that award winning project on this, and that's not, page 19 just tells you a little bit more about what those are.

And page 20 is a really coming a little bit at it from the customer angle, which of course is really a progress INAUDIBLE we use on every decision that we make, but we agreed this a very good project for customers, also. It's going to provide them with energy security, provide them with economic power, and as was said, the Public Utilities Commission will look at this thoroughly as they always do.

And I think we need to remind people sometimes, so it will help you put their allegations in perspective, is New Hampshire has an open access system, and many of you were part of that. Many of you created that law and that policy, and certainly I was part of it. And what that means is that any customer, any customer can choose a power supplier. Now we know on a practical level, residential customers don't get that choice because people aren't offering that. But we know on the business side, commercial customers, we know that they can and do choose power suppliers other than PSNH.

Our role, our role as set by state law, our role is to provide power to customers when they haven't chosen a supplier. Some people call that the supplier of last resort. It just so happens that most customers do not choose a supplier. But commercial customers can. So when a commercial customer says, I'm concerned about the cost, you know, I don't want to be flippant about this, but if they really are concerned about the cost and if we really aren't low cost, they can go somewhere else and they can completely avoid the costs of a scrubber. But that's not, you know, what we're trying to do is to have the lowest cost power that we can for the benefit of customers. But if people think that we're out of line, they have recourse. They have recourse through prudency review and they have recourse by, they can make a choice for a different power supplier. And that's just the point that sometimes is lost when people make allegations and ...

It's interesting to me that Senator Janeway says this isn't about cost. And I think he's right. I agree with him. This isn't about cost, this is about people who want to shut down Merrimack Station.

On page 22 is the project benefits and I've mentioned many of them. Of course, jobs right now is always very important to us, and I thank people for complimenting us for how we treat employees. I'm one of those employees, and we always try to treat our employees well, and we always try to treat our contractors well, and we always try to treat people who work on our sites well. And we're looking forward to having many of you on the site and working hard. We know you do good work. We've had lots of experience with contractors doing great work and we're going to do it again. But jobs is very important. The local economy.

I mentioned passenger rail. There will be more and railroad help, we talked about that. I talked about the energy values of this plant already. I mean the values to me are just so overwhelming, just as some people would say a no brainer, that you really want to maintain a plant like that, and you really want it to be as clean as possible.

Regarding Senate Bill 152, I tell you, it's very unusual for me to testify before you these days, so the reason I'm here is because I just think that it is so, it's such a dramatically negative impact and I really need to, really need your vote against this bill. It is not a simple study bill. It is far more serious than that and, you know, my point of view, not a point of view, it's really my experience. As I say, you can spend any amount of money you want on this study and it won't tell you the future. I think Senator Gatsas had exactly the right question. What are you going to do with it when you get it? Because at best, it's going to be speculative, it's not going to tell you anything. And all it will do is feed the fire and all it will do is cause more fighting and disagreement and people following different agendas.

As I said, as an electric company what we do is we try to provide for certainty in an uncertain world. And one way to provide for certainty in a very uncertain world is to make the power plants as clean as possible and to install the scrubber. As I said, the scrubber is really our hedge against federal regulations. You know, I'd rather do it now when it's less expensive than to do it five years from now, when there's federal regulations, when every other power company in the country is putting in scrubbers. It's better to do it now, and I think it'll do us well.

Senator Martha Fuller Clark, D. 24: Mr. Long?

Mr. Long: Yes, ma'am?

Senator Martha Fuller Clark, D. 24: I wonder if it would be possible to wind this up.

Mr. Long: I'm just about finished, as you can tell. I'm on slide 25, with only a couple other ...

Senator Martha Fuller Clark, D. 24: You've provided a lot of very good information in there and it's not that we don't appreciate and that we don't take your testimony seriously, but you have spoken for 30 minutes.

Mr. Long: Oh, I'm sorry, yup, a little bit longer than I normally go. But if, Senator, you could just bear with me a couple more minutes, I think I can wrap this up.

Senator Martha Fuller Clark, D. 24: Certainly.

Mr. Long: Thank you. On page 25, I guess you can read it at your leisure, but I just want to point out to you, because some people think the study is going to provide answers, and it won't, and I want to tell you what it won't give you. It certainly won't tell you what the cost of the scrubber is or what Merrimack Station's fuel source is. We know that. And it won't tell you what the price of oil, gas or coal, and it won't tell you what future regulations you're going to have. So it really, you can spend money and you can have a study, but to what end? I think the only end is, I guess, give you a platform to say shut the plant down.

Qm

Page 26. I guess I'm done, Senator. With that I can just, I really do want to focus on just one more slide before I leave, and it's slide number 28, and many of you have heard me say this before. And it's just one slide, but I would tell you, Senators, in some ways this is the most important slide in the whole package. Because I really don't think we should be here today talking about Merrimack Station. I think that should simply be going forward in the way that we've all agreed.

What we should be talking about is how can we have more renewables. And what this page is saying is what PSNH is doing and what we think should be done. And you can see we think energy efficiency is a huge part of our future, and that's what we should be talking about. How do we get more of that? How do we do that well? How do we work together on that? You know, how do we keep looking for innovative ways in our power plants? You may have read, you may have heard, that we're going to test burn cocoa beans in our power plant. Those are the kind of things that we do and then invest in renewable energy projects. That is not going as fast as I would have liked, and I personally think that you can never have too much renewable energy power. And you all know my position, that PSNH would like to build an INAUDIBLE and employ some of these people on that front too, doing renewable energy projects. But you know that for three years now, the Senate has said no. But we're not here today to talk about that. But I think that's really the sorts of things that we should be talking about, instead of having to spend so much of our efforts doing something that has already been done, which is put a scrubber at Merrimack Station.

I guess finally I just ask you for your support, for the all these people in this room, for our customers, for our energy future, that you vote against Senate Bill 152. Thank you.

I would like, Senator, to bring Gary Fortier up for just a minute so he can give the scrubber perspective, too.

Senator Martha Fuller Clark, D. 24: Thank you very much. I would like to say that I look forward to working with you on making sure that we can provide the transmission to the North Country so that whatever projects are being, moving forward in the North Country are going to be able to come to fruition. Without transmission, nothing can move forward, so we know that you're a key player in that and we do look forward to working with you to solve that problem.

Mr. Long: And I, too, with you, Senator, am interested. And there are some even more substantial things we can do with transmission than the northern route, but we certainly want to do that. And I will tell you, there's renewables that we can do now that don't require transmission. So, all those things I think we should pursue together.

Senator Martha Fuller Clark, D. 24: Absolutely. I wanted to ask you one question, which was some concern that I have that when you're looking at the cost of commodities, that your chart ends in 2008. It doesn't show what's happened to commodities since the market of last summer, which we know, the costs were very high. The costs now have come down. Do you have the stability in your contracts? I know that you said ...INAUDIBLE

Mr. Long: Yes, Senator, I would say we're in very good shape, and I really want to compliment the team, the PSNH engineering team and project team. I'm very, very comfortable and very pleased with their, you know, marvelous execution so far. And yes, we provided, we have room in the contract. We provided for escalation of materials and we provided for contingencies. If we don't have to use those escalations because the markets have changed and some prices of some things have gone down, or at least stayed flat, because sometimes we built in escalations in case they didn't stay flat. So, yeah, we are already seeing reductions in costs that we are capturing as we go forward. So, yes, we believe that that's why, as I mentioned earlier, this is like the highest it would ever be, 457, and you know, again, until you run the course you won't know what the final numbers are. But our team feels very confident that there's things that we can exercise along the way.

The bad news is we're in a recession. I mean, nobody wants that. But if you're in that circumstance, you might have some leverage to get some cost savings for materials, but there still is a world demand for scrubbers and there still is, it's still a very vibrant market.

Senator Martha Fuller Clark, D. 24: INAUDIBLE

Senator Jacalyn L. Cilley, D. 6: Thank you, Madam Chair, hold it down, okay. Thank you, Madam Chair. Mr. Long, I have been following this now for weeks, and I have heard evidence on both sides of the fence about, you know, whether that plant is actually an integral part of the, you know, the supply of electricity, and that we really could do without it and have adequate supply. I'm wondering if you could speak to that, and I'm also wondering why, doesn't ISO New England issue, I think it's FERCs, it's been a little while since I've visited those, that suggest a concern about supply in the future?

Mr. Long: Thank you, Senator. I tried to keep things from getting too complicated, because electricity is fairly complicated. But the short answer

Bm

to your question is that plant is absolutely critical to supplying our customers. Okay, now we have to distinguish our customers from the rest of New England. But that plant is clearly used to serve our customers, and we don't have enough power to serve our customers. We're buying power on the wholesale market. We buy 300 to 400 megawatts of power on the wholesale market. So, certainly from the perspective of the economics to our customers, it's critical.

When you look at New England generally, and we are operating as a single region, the recession has resulted in less electric load now than we had earlier. So, I mean, the recession is having a very large impact on everyone. So right now, and I think Senator Janeway, you know, said that prices are low. Prices have gone down, and as I said, I've seen many cycles of up and down. I mean, if you want to bet the farm on the prices today, I certainly wouldn't. But, you know, so prices are low now, which is good. It's kind of an offset to the recession. But no one expects that to hold. And so there's enough power in New England. There's enough power in New England. I should say it this way, on paper, there's enough generating capacity to serve the load. And there isn't any real load growth happening in New England right now.

But that doesn't mean, that doesn't mean that's economic for customers, it doesn't mean that at all. And it doesn't mean that that power is available all the time. We've had two times in the last, I think, three years where there's been a shortage of gas supply, and what happens when there's a shortage of gas supply, is several of the gas plants in New England can't run and I think the mention of our turbines, our combustion turbines running is kind of the result, sometimes the result of plants just not being able to start up. Sometimes it's just the result of plants just not being able to run. And that's what happened. You know, there's destruction in the gas supply and we were called on to run anything and everything we could so New England would have enough power, and that doesn't happen often, but it can happen. And so, in our business, that's why I say, it is so important to have fuel diversity, it's so important to have flexibility, and that's one of the things that Merrimack Station does for us.

<u>Senator Martha Fuller Clark, D. 24</u>: Thank you very much. Senator Carson.

<u>Senator Sharon M. Carson, D. 14</u>: Thank you, Madam Chair. And thank you for your testimony this morning, Mr. Long.

<u>Mr. Long</u>: Thank you, Senator.

Senator Sharon M. Carson, D. 14: I pulled some of the testimony from the original bill that established the scrubber project, and I discovered that not only are we looking to reduce mercury emissions, but we're also looking to reduce the sulfur dioxide emissions. And that is really substantiated in the program that you provided us with this morning. One of the things that I did not know was that we were paying for these sulfur dioxide credits. Are we still paying for those?

Mr. Long: Yes. We, as an emitter of sulfur dioxide, we have, there's a cap and trade system, you know, much like what people talk about for CO^2. Not the same design but the concept. And it's been in existence for a number of years and it's been proven to work very well, about reducing sulfur. And so, you know, it wasn't required by law to reduce sulfur, you know, that mercury law. It was really focused on mercury, as others have said. But at that time, we did a two-fer, those were the kind of words used back then. We get to have two major reductions with one piece of equipment, because these flu gases, desulfurization are mainly for the purpose of reducing sulfur. So we got a huge reduction in sulfur, which means we avoid having to buy sulfur credits on the market, on the cap and trade market. So that produces economic value, it's an offset to the cost. Not an entire offset, but it helps offset the cost and so, yeah, it's a very good thing for us. And it helps us look at different sources of coal, because if the coal has a little more sulfur in it than the coal we'd normally buy, but we now have a way of getting rid of the sulfur with this device, which means we're open up to more markets, and that affects rail in a positive way as well as cost.

Senator Martha Fuller Clark, D. 24: INAUDIBLE.

Senator Sharon M. Carson, D. 14: Thank you, Madam Chair. So if you were to give us some sort of an estimate, what do you think would be the cost benefit to the ratepayer?

Mr. Long: I guess I'd like to do that as a follow-up, because I'm not an expert and I know that two years from now, someone will say, gee, Gary, you said sulfur credits were this, and the market changed and the facts. So, you know, again, it would be an estimate based on today's costs and I think one of our staff can certainly provide that for you, Senator.

Senator Martha Fuller Clark, D. 24: Senator Odell.

Senator Bob Odell, D. 8: Thank you, Madam Chair. A couple, Mr. Long, thank you for your testimony. A couple of times this morning you have mentioned that there's a cost for this study of a $1 million or $2 million. Who would be the payer of that?

OSM

Mr. Long: You know, Senator Odell, I didn't mean to imply that this would cost that much. We're not advocating any study, so it costs zero if you ask me. But I'm just saying, I have seen studies where you can pay consultants $1 million to do a study, and I personally would not use the results of that study because of speculation. And if you spent $100,000, $200,000, $1 million, my point being that money will not buy you an answer. That no matter how much you spend, you can look at what you think is the world's renowned expert, you know, but they can't tell you what an oil price is going to be three years from now, four years from now. There are some markets that you can buy and sell one or two years ahead. You can't buy five, six, ten years ahead. Nobody's foolish enough to believe that they can forecast.

Senator Martha Fuller Clark, D. 24: Follow-up. ..

Senator Bob Odell, D. 8: Mr. Long, my question was, if it costs a dollar or it costs a $1 million to do this study, who ultimately pays for the study?

Mr. Long: I don't know. I guess that would be for you to decide, but if you vote the bill down, you don't have to decide. But you know, it's, I would think that it would be a bad use of money from customers, so I certainly hope our customers don't have to pay for it.

Senator Martha Fuller Clark, D. 24: INAUDIBLE

Senator Bob Odell, D. 8: Thank you, Madam Chair. I understand correctly and some of the concern is that you've had 33 years of experience, you must have had projects like this in the past, and I know you mentioned the Shiller Boiler, where you are asked, you are legislatively told to go ahead with the project or you initiate a project. You spend the money and then the Public Utilities Commission looks at that and says, yes, this cost is in, that cost is out. In other words, the Legislature has ennobled (sic) the Public Utilities Commission to fulfill that role. Is that a normal standard, that lookback, in terms of what will go into the rate base?

Mr. Long: It is the normal standard for the Public Utilities Commission to review our actions and our decisions, and it's done in hindsight. So it certainly presents business risk, as you might have a difference of opinion. We might think we made a good decision, somebody else might think we made a bad decision. But I think the Commission has found over and over again that we're making good decisions. But yes, that's normal course. And that's okay, we're totally prepared for that and we're totally used to that.

What is difficult for us because, you know, we're really, whatever we do affects customers. You know, we're a regulated company, we don't get market prices. We don't get the profits that a nuclear plant gets when the market prices go up, you know, or any other plant if it's not regulated. So we have to be very careful. First of all, because we have that scrutiny. Second of all, you know, it affects customers. So we're basically very conservative. We think we're very innovative when it comes to things like wood burning or like cocoa bean shell burning or, you know, renewable power. But financially we have to be very, very conservative and we have to be very sure of what we're doing, because if we're reckless or if we're making bad decisions, it'll hurt, it'll come back on us.

Senator Martha Fuller Clark, D. 24: Thank you very much.

Unknown: My name's Lynn INAUDIBLE and INAUDIBLE for PSNH. And this question was asked of us awhile ago because I think INAUDIBLE question, whether or not INAUDIBLE.

Senator Martha Fuller Clark, D. 24: Could you just wait one minute. We'll be able to get your answer, but it won't INAUDIBLE.

Mr. Long: I must have said something that my staff disagrees with me, so no.

Senator Martha Fuller Clark, D. 24: INAUDIBLE. What I would like to do now, INAUDIBLE to come forward, will not be able to INAUDIBLE this afternoon. It is my intention to break the morning session at noon and reconvene at 12:30. At that time, I will ask the representative INAUDIBLE to come forward. Is that?

Mr. Long: Thank you very much, Senator. That's perfectly acceptable, just as long as you get the information, I think you'll find it useful.

Senator Martha Fuller Clark, D. 24: INAUDIBLE, so wait before the public can INAUDIBLE, we'll hear from Senator D'Allesandro. INAUDIBLE if you could line up, I will call on you.

Senator Lou D'Allesandro, D. 20: Thank you, Madam Chairman, and distinguished members of the Committee. For the record, my name is Senator Lou D'Allesandro, I represent District 20. That's Manchester, Wards 3, 4, 10, 11 and the Town of Goffstown.

I come before you in opposition to Senate Bill 152. I'll be extremely brief. We as the Legislature mandated that PSNH do this. We told them to do this

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request TC-04
Dated: 08/31/2012
Q-TC-013
Page 1 of 5

Witness: William H. Smagula
Request from: TransCanada

Question:
Reference page 16, line 10, of Mr. Smagula's June 15, 2012 prefiled testimony in this docket, please provide copies of any and all "published cost statements" that have been issued in connection with the scrubber project since its inception.

Response:
The Clean Air Project Team published three cost estimates. These updated estimates are presented in the company's Form 10-Q quarterly filings attached below. The Clean Air Project Team presented a site specific cost estimate of $457 million in May 2008 which was approved by NU's Board of Trustees in July 2008. The Clean Air Project Team updated the estimated project cost to $430 million in the second half of 2010. A third and final update in the first half of 2011 estimated a project cost of $420 million.

Public Service Company of New Hampshire
Docket No. DE 11-250

Data Request STAFF-01

Dated: 12/30/2011
Q-STAFF-012
Page 1 of 75

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

Question:
Please provide copies of all reports to the Legislative Oversight Committee on Electric Restructuring and other persons pursuant to the requirements of RSA 125-O:13,IX.

Response:
The requested information is attached.

PSNH Legislative Update- June 18, 2008*

Update relative to the reduction of mercury emissions at PSNH Coal Fired power plants as outlined in HB1673.
As required by HB 1673 (RSA 125-O:13 Compliance- Paragraph IX) PSNH shall report by June 30, 2007 to the legislative oversight committee on electric utility restructuring, and the chairpersons of the house science, technology and energy committee and the senate energy and economic development committee, on the progress and status of;

1) Achieving early reductions in mercury emissions:

DOE Mercury Reduction Project at Merrimack Unit 2

- Program Schedule Fall 06 – Spring 08
  - Completed Parametric Testing Nov 2006
  - Completed Long Term Testing April 1, 2008
  - Used various combinations of sorbents to assess effectiveness
  - Varied rates of injections
  - Varied location of injection points
- Long term Test Evaluations
  - Long term test – Fall 2007 thru March 2008
  - Equipment performance
  - Balance of Plant Issues
  - Mercury Removal Performance
- Measurement tools and methods
  - Completed sorbent trap measurements
  - Installed and monitored Hg CEMs
- Results of Parametric tests
  - Initial injection plan 10 – 30%
  - Enhanced injection resulted in a wide variation of results
  - Sustainable results will depend on the ability to resolve balance of plant issues

2) Installing and operating the scrubber technology:

CLEAN AIR PROJECT UPDATE

- Engineering
  - Projects defined in 5 major components
  - Specifications developed for 4 key components
- Commercial and Purchasing
  - Program Manager Hired Sept 2007
  - Scrubber Island and Chimney proposals are in negotiations
  - Vendor Proposals requested and received for Wastewater Treatment Facility and Material Handling System
- Review, Permits and Approvals
  - NHDES – May 12 presentation
  - Temporary Permit expected October 2008
  - Town of Bow – Local permitting
  - Regional Planning Commission
- Site work
  - Existing oil tank removed
  - Site surveys and studies completed
  - Warehouse construction underway
  - On-site engineering facilities completed
- Schedule and Costs
  - Tie-ins: MK#1 Fall 2012, MK#2 Spring 2013
  - Project Costs will be updated with review of major equipment bids

*year corrected to reflect June 2008 update

ORIGINAL
N.H.P.U.C. Case No. DE 11-250
Exhibit No. 27 - 18
Witness William H. Smagula
DO NOT REMOVE FROM FILE

Public Service Company of New Hampshire	**Data Request STAFF-01**
Docket No. DE 11-250	**Dated: 12/30/2011**
	Q-STAFF-012
	Page 1 of 75

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

Question:
Please provide copies of all reports to the Legislative Oversight Committee on Electric Restructuring and other persons pursuant to the requirements of RSA 125-O:13,IX.

Response:
The requested information is attached.

Long
EXHIBIT NO. 18
9/16/13
S. ROBIDAS

Public Service Company of New Hampshire
Legislative Update – June 29, 2010

Merrimack Station
Clean Air Project

Cost, Contract, Construction, and Schedule Update

I. DOE Mercury Reduction Project at Merrimack Station – Unit No. 2

- Field testing ended in Q2, 2008
- Data compiled and submitted to DOE
- Conclusions: Only 40%-60% mercury reduction demonstrated; longer term testing would be required to further study operational impacts

II. Clean Air Project Update

- Engineering – 95% complete
- Commercial and Purchasing
  - Over 85 contracts are in place; approximately 5 remain to be issued
  - Contracts currently total $306 Million; remaining contracts could total up to $35 Million
- Permits and Approvals
  - All construction permits are in hand; EPA/NPDES liquid discharge permit application has been submitted
- Site Work
  - 240 craft workers are working on-site plus 95 management and support personnel
  - Over 30 companies are involved on-site
  - Major construction is heavily engaged in all areas
  - Project has been a significant boost to the local economy
  - Over 440,000 man-hours expended to date
  - Excellent safety record – no lost time accidents
- Schedule
  - On track to be done 1 year early – 7/1/12
  - 2010 is primarily a heavy construction year
  - 2011 continues with construction then transition to begin equipment and system testing and commissioning, and training
- Cost
  - Project cost continues to be in line with estimates; high confidence in not exceeding budget

Public Service Company of New Hampshire
Merrimack Station - Clean Air Project (CAP)
June 2011 Legislative Update
(Additional September 2011 Updates Noted)

Major Project Milestones

Safety	Cost	Schedule
Over 1,000,000 man-hours without a lost time accident 1,200,000 man-hours through September 2011	Cost estimate reduced from $457 M to $430 M in October 2010	Project remains on track to be completed 1 year early.

II. DOE Mercury Reduction Project at Merrimack Station – Unit #2

- Field testing ended in Q2, 2008
- Data compiled and submitted to DOE
- Conclusions: Only 40%-60% unsustainable mercury reduction demonstrated with operational concerns identified.

Additional Updates

- The facilities continue to complete two mercury emissions stack tests per year at Merrimack 1, Merrimack 2 and Schiller Station .
- Methods for stack testing of mercury emissions and mercury continuous monitoring equipment continue to be developed although the accuracy still remains less than current continuous emissions monitoring (CEMS) equipment for SO2 and NOx emissions. This is not unexpected given the extremely small quantity of mercury emissions to be detected in a much larger exit flue gas stream.
- With the ongoing stack testing and the fuel testing and management, PSNH continues to investigate and test different coal blends to reduce mercury emissions.
- Achieved concurrence with NH-DES on the Clean Air Project's CEM strategy and functionality to support proper equipment procurement, installation and subsequent testing/monitoring.

Public Service Company of New Hampshire
Merrimack Station - Clean Air Project (CAP)
June 2011 Legislative Update
(September 2011 Updates Noted)

2006 June	2007	2008	2009 March	2010	2011 June	2011 Sept	2012	2013 July 1
The NH Legislature passed the scrubber law.			*DES issues the scrubber construction permit.*		*Clean Air Project 84% complete.*	*Clean Air Project 90% complete*	*Project Completion expected mid-year.*	*Statutorily required completion date*

I. CLEAN AIR PROJECT UPDATE

Engineering, Contracts and Procurement

- Engineering – 96% complete (98% complete as of Sept 2011)
- Contracts and Procurement
  - About 100 contracts have been issued; valued at approximately $330 M
  - Remaining contracts yet to be released- 4 or 5 at a value of $15-$18 M (All contracts have been issued.)

Construction and Site Activity Schedule

- Construction
  - In 2010, the majority of heavy construction was completed.
  - In 2011, installation of buildings and equipment continues to be finalized.
    Equipment start-up and system testing has begun.
    Integrated unit operations testing will begin this fall.
- Site Activity
  - Approximately 20 different contractors on site
  - Approximately 225 workers with 150 union craft labor on site (150 total as of Sept 2011)
  - Labor on site peaked at about 500 workers during last winter
  - Over 1,200,000 contractor man-hours expended
- Schedule
  - In 2012, performance testing to be completed with goal of full optimization mid- year.
- Economic value to New Hampshire
  - Use of over 50 local companies and hundreds of New Hampshire residents
  - As much as $50 million spent in the local economy

Clean Air Project

Merrimack Station

March 31, 2010
NH Public Utilities Commission
Docket 08-103 Informational Session

Public Service
of New Hampshire

The Northeast Utilities System

Agenda

Clean Air Project
Merrimack Station

- Introductions
- Project Overview
  - Purpose of the Clean Air Project
  - How the Technology Works
  - Project Status
  - Contracts Summary
  - Budget
  - Schedule
  - Jobs
  - Project Benefits
- Photos
- Discussion

Clean Air Project
Merrimack Station

Introductions

- Bill Smagula, Director - PSNH Generation
- Lynn Tillotson, Technical Business Manager
- Steve Hall, Rate & Regulatory Services Manager

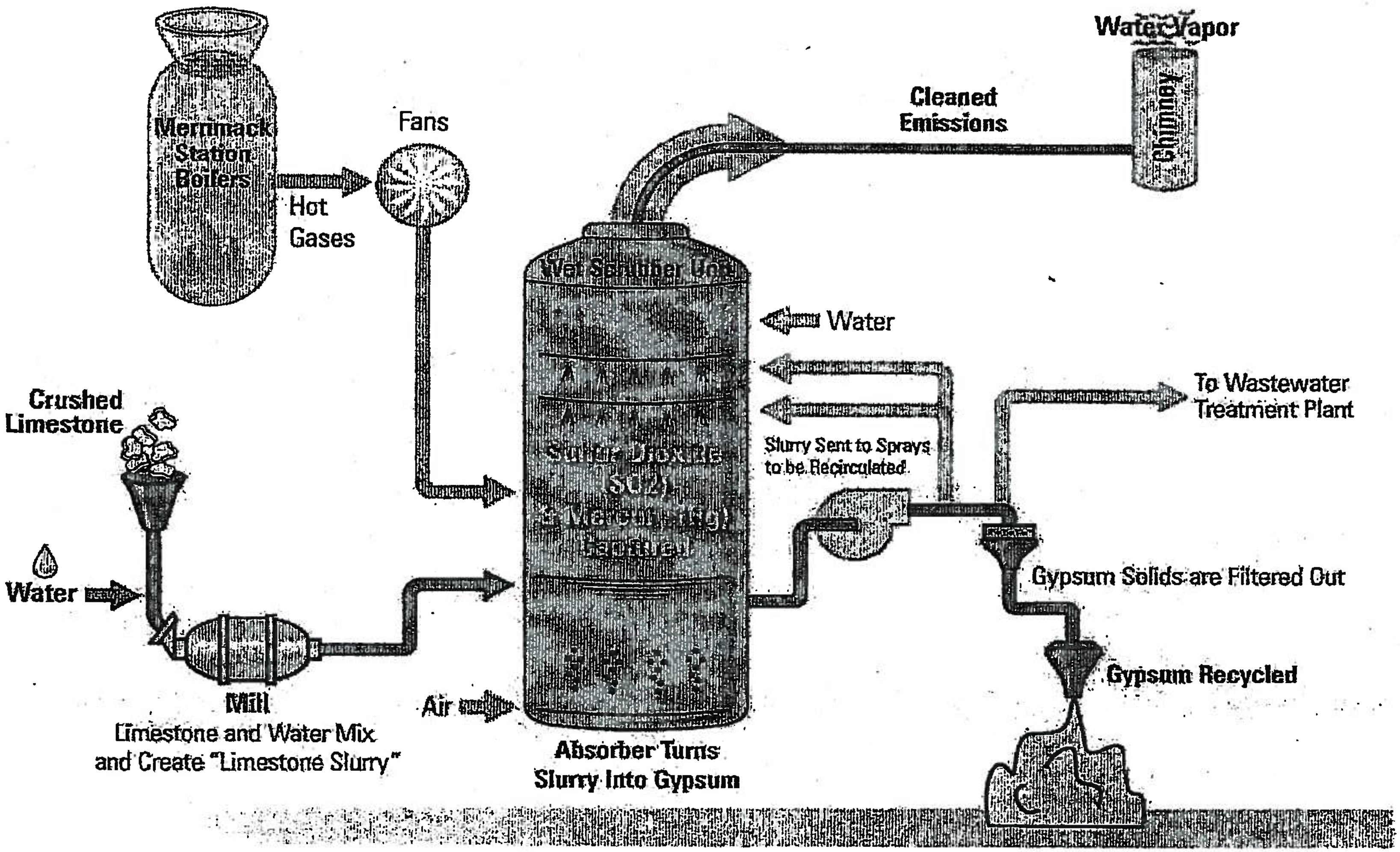
3

Purpose of the Clean Air Project

Clean Air Project
Merrimack Station

- Comply with the State law (RSA 125-O:11-18) that requres the installation of the wet flue gas desulfurization technology at Merrimack Station by July 1, 2013
- Achieve significant reductions in mercury and sulfur dioxide emissions
  - 80% Mercury
  - 90% SO_2

How the Wet Flue Gas Desulfurization Technology Works



Project Status

Clean Air Project
Merrimack Station

PSNH is 2/3's through the six-year project

- Engineering is almost complete
- Over $300 Million and over 85 contracts committed
- Construction is in full swing
- Over 300,000 man-hours expended to date

Contracts Summary

Clean Air Project
Merrimack Station

	$ Millions
Major Supplier Contracts	$165.6
• Scrubber	
• Material Handling (Limestone, Gypsum)	
• Waste Water Treatment	
• Chimney	
Large General Contracts	$ 97.1
• Foundations	
• Duct Work and Installation (3)	
• Site Work (8)	
• Project Management	
Specialty and Service Contracts	$ 33.6
• Electrical, Sound, Cranes, Fans, Emissions Monitors, Insulation, Legal, Etc.	
OVER 85 CONTRACTS – IN PLACE TO DATE:	**$306.3 MILLION**

Approximately five contracts remain to be issued over the next few months totaling about $35 Million

Budget ($ in Millions)

Clean Air Project
Merrimack Station

	Thru 2007	2008	2009	2010	2011	2012	2013
Cost By Year		24.8	119.3	148.6	99.0	59.2	3.4
Cumulative Cost	2.7	27.5	146.8	295.4	394.4	453.6	457.0

Schedule
Merrimack Station Clean Air Project

Project	2006	2007	2008	2009	2010	2011	2012
NH Mercury Reduction Act							
Preliminary Engineering							
Program Manager Hired							
Detailed Engineering							
Major Contracts Awarded							
Major Permitting							
Preliminary Site Prep.							
Major Construction							
Testing & Commissioning							
In Service							

Clean Air Project
Merrimack Station

Jobs

- Clean Air Project – Currently Active On-Site
  - 31 companies
  - 215 craft workers
  - 75 supervisory and support personnel
  - Over 300,000 man-hours expended to date
- Merrimack Station
  - 110 employees
  - Annual outages temporarily increase work force twice a year
  - Merrimack Station uses over 100 local businesses for labor and materials
- New Hampshire Economy
  - CAP has spurred local economy: suppliers, small businesses, housing, restaurants, etc.
  - Local suppliers: concrete, site work, labor, equipment rentals, security, fuel tools, parts, food, etc.

Project Benefits

Clean Air Project
Merrimack Station

Reduced Emissions

- Mercury – 80% reduction or better
  - Capture about 220 pounds of mercury/year
- Sulfur – 90% reduction or better
  - Capture about 31,000 tons of SO_2/year
- Provides additional reduction to particulate emissions

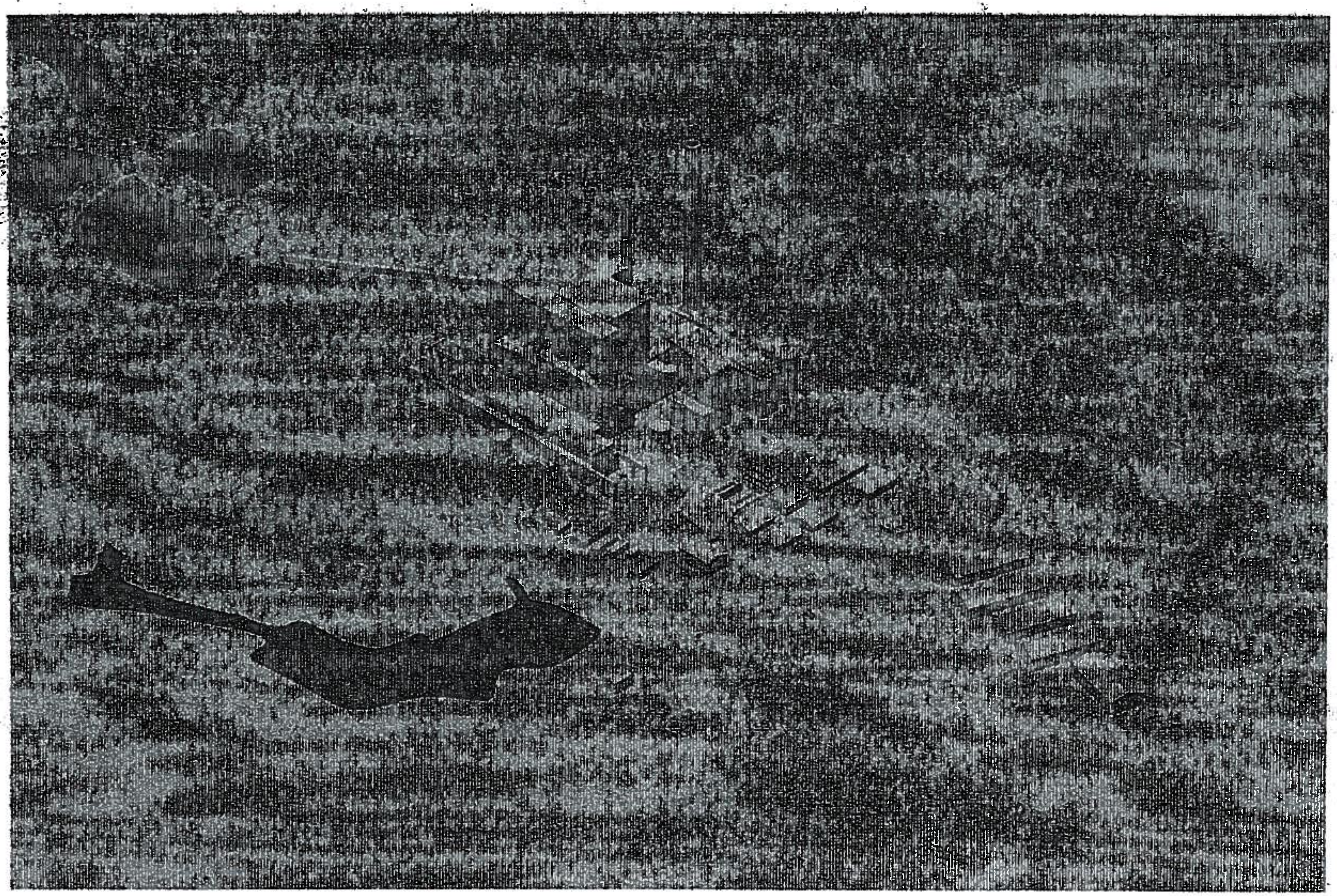
Early Completion = Early Emissions Reduction

- Scheduled to be done by July 1, 2012 (one year early)

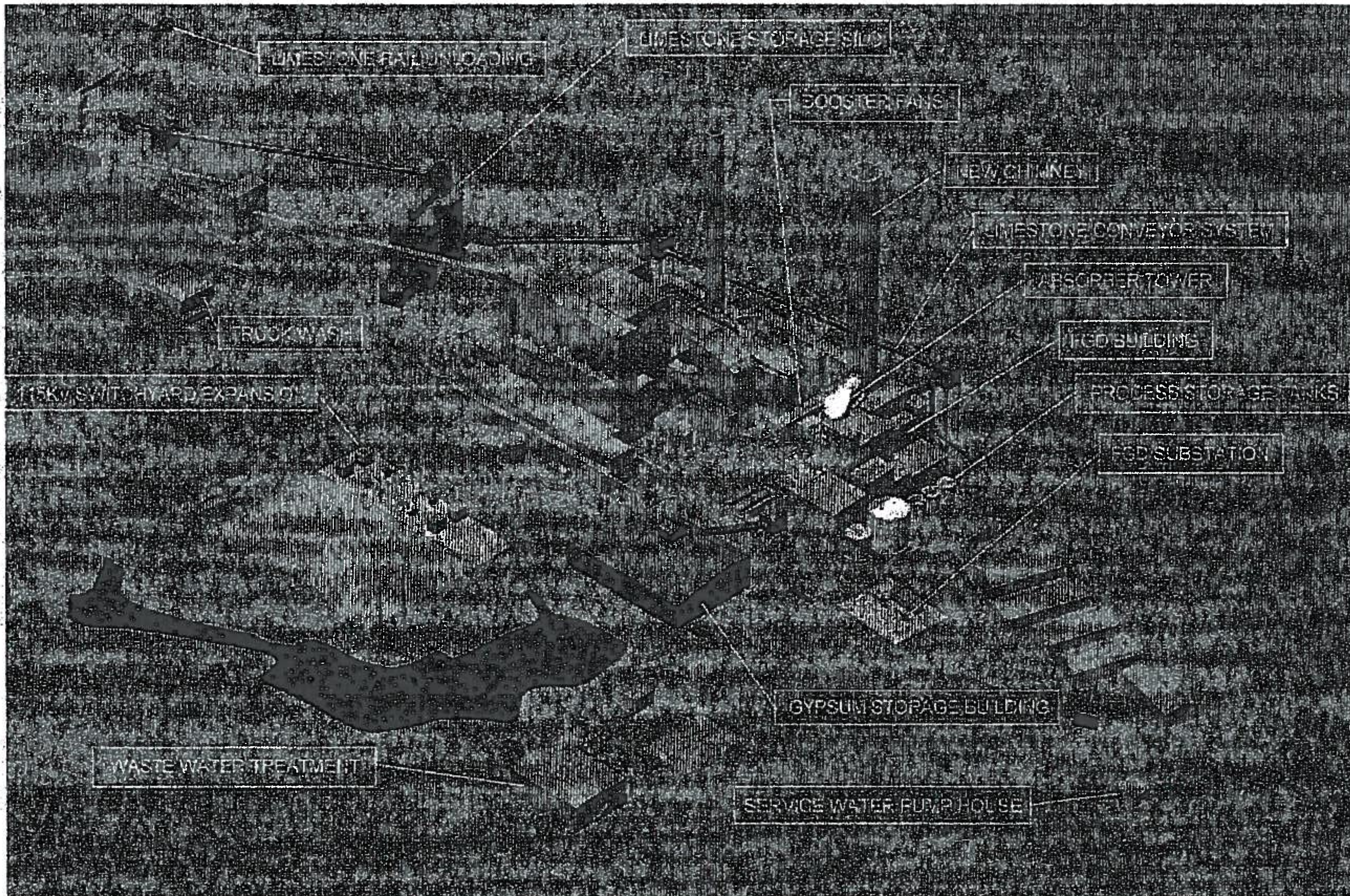
Direct Economic Benefit of Project Workforce: $50 Million, 400+ jobs

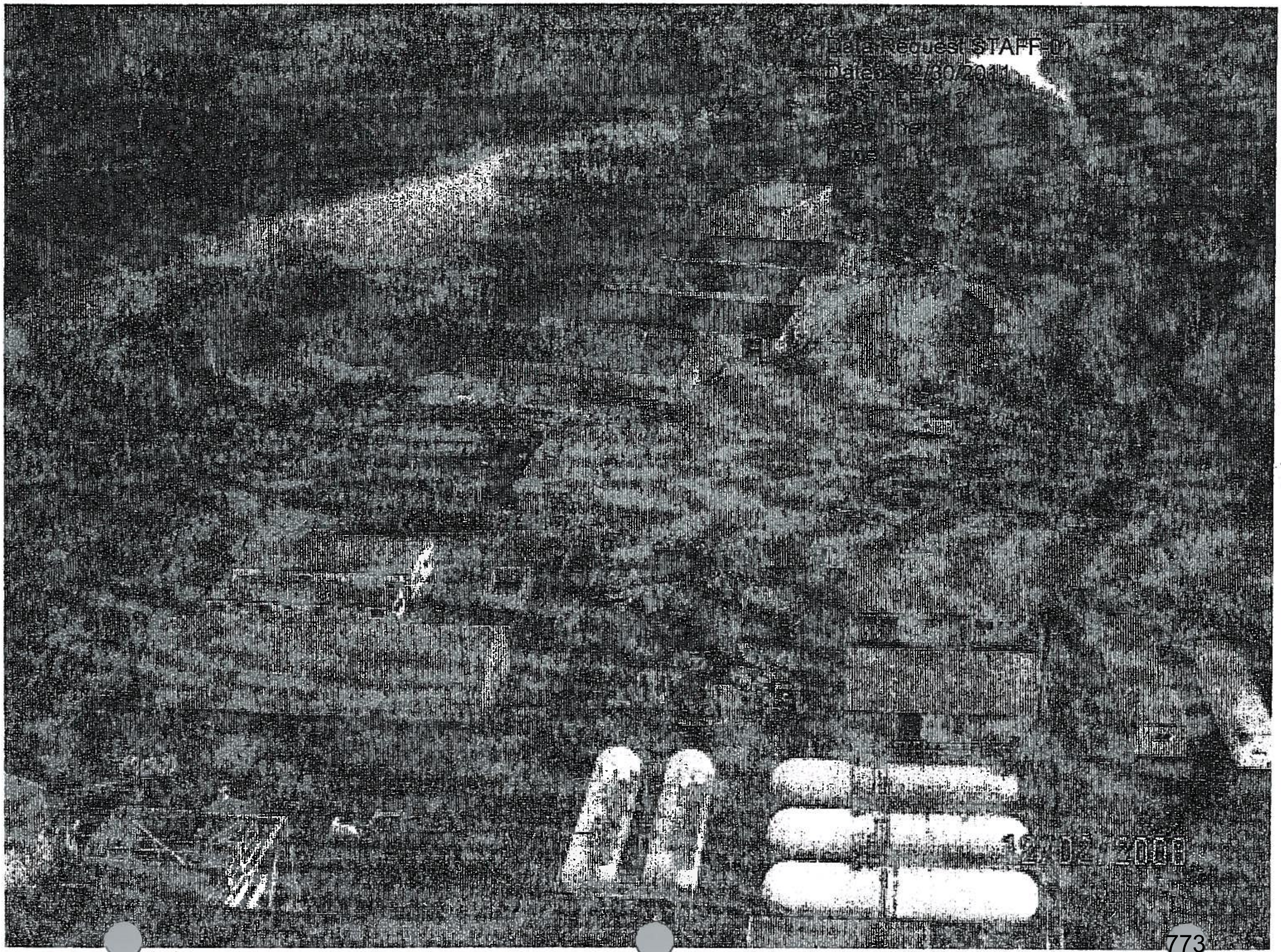
Reliable Energy, from one of the lowest emission coal plants, as a bridge to the Future

Merrimack Station: 2008



Merrimack Station: 2012

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Dated: 12/30/2011
12/02/2008