Dark Days Ahead:

Financial Factors Cloud Future Profitability at Dominion's Brayton Point

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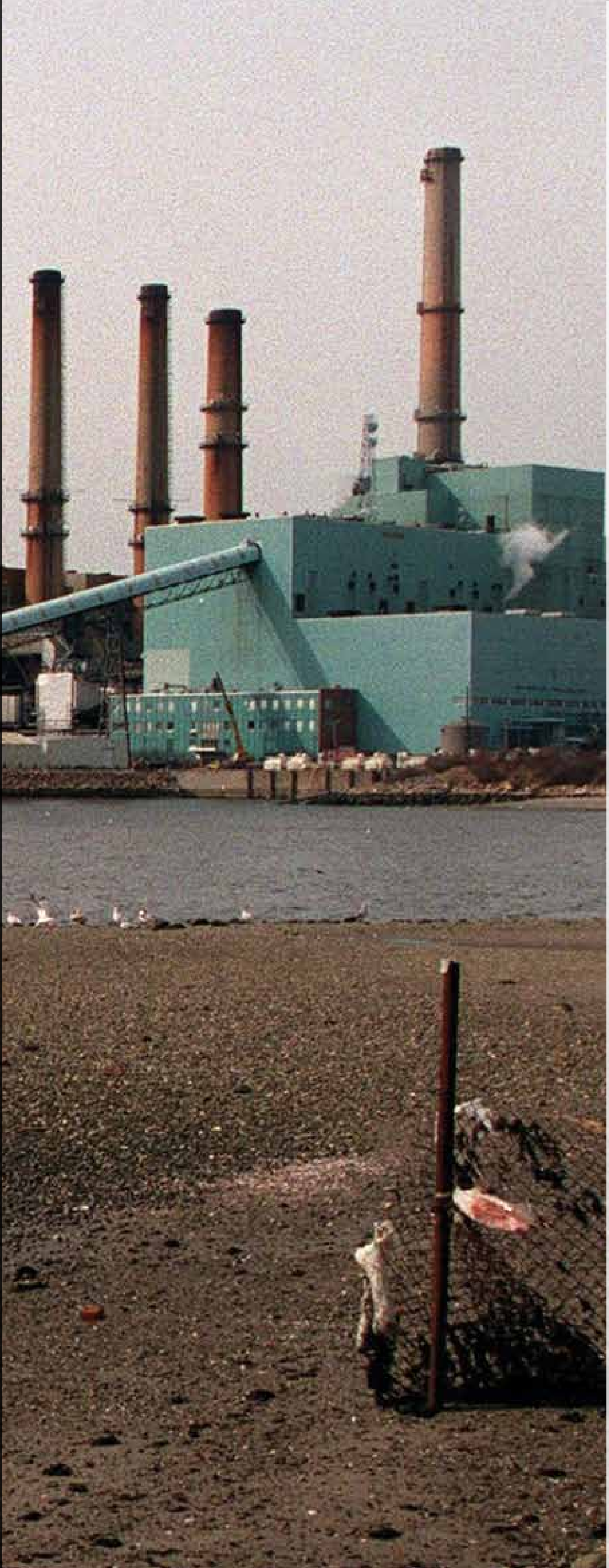

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AUTHORS:

David Schlissel has been a regulatory attorney and a consultant on electric utility rate and resource planning issues since 1974. He has testified as an expert witness before regulatory commissions in more than 35 states and before the U.S. Federal Energy Regulatory Commission and Nuclear Regulatory Commission. He also has testified as an expert witness in state and federal court proceedings concerning electric utilities. His clients have included state regulatory commissions in Arkansas, Kansas, Arizona and California, publicly owned utilities, state governments and attorneys general, state consumer advocates, city governments, and national and local environmental organizations.

Mr. Schlissel has undergraduate and graduate engineering degrees from the Massachusetts Institute of Technology and Stanford University. He also has a Juris Doctor degree from Stanford University School of Law.

Tom Sanzillo has 30 years of experience in public and private finance. As first deputy comptroller of New York State, he was in charge of over $150 billion in state and local municipal bond programs and was responsible for a $156 billion global pension fund. Over the last six years Mr. Sanzillo has authored reports and testimony on public and private energy finance, coal, coal mining and exports in twenty states, including financial analyses of coal plants in Texas, Georgia, South Carolina, and Pennsylvania.

PURPOSE

The purpose of this Report is to inform policymakers and other interested stakeholders regarding the future of the Brayton Point power plant in Southeastern Massachusetts.[1]

There are four generating units at Brayton Point: Units 1-3 are coal-fired although each unit has some potential to burn natural gas. Unit 4 is oil-fired. The units range between 38 and 50 years in age and can produce a total of approximately 1,580 megawatts ("MW") of power.

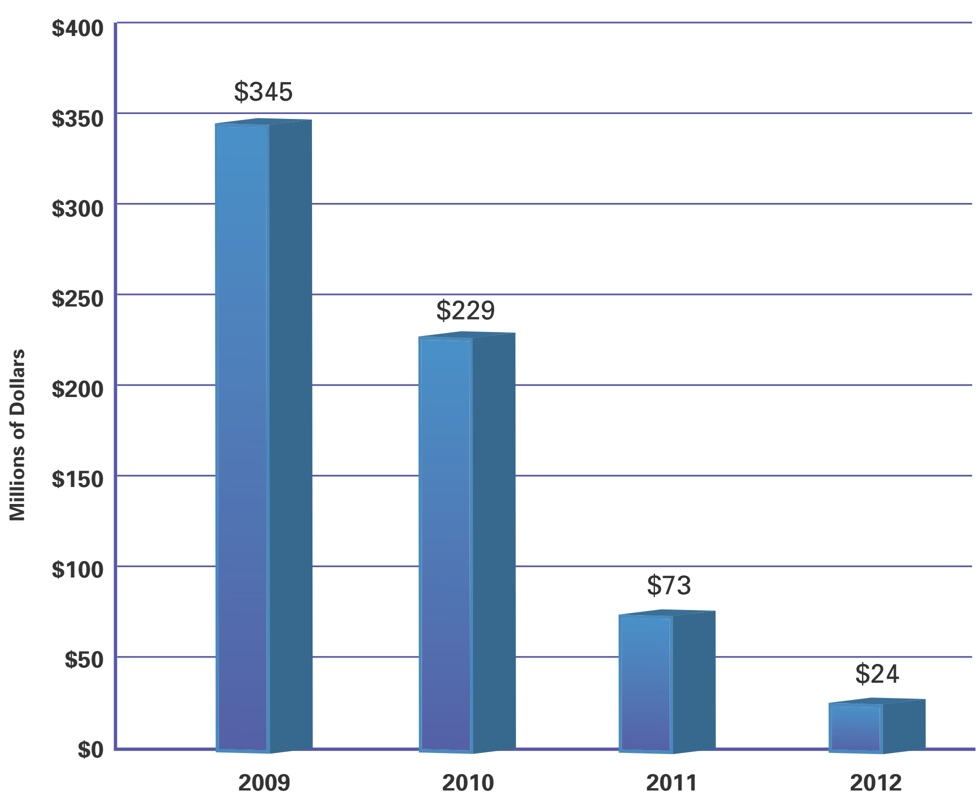
Brayton Point is currently owned by Dominion Resources ("Dominion"), although, having just completed a $1 billion investment in a new scrubber and new cooling towers, Dominion has said that it is in the process of selling the plant along with two other fossil-fired plants in the Midwest.

Our analysis is based on Company and ISO-NE reports and documents. We also have relied upon financial analyses prepared by UBS Investment Research and information developed or reported by SNL Financial, L.L.C.

CONCLUSION

Our ultimate conclusion is that, quite simply, the future for Brayton Point looks bleak whether Dominion continues to own the plant or another owner steps forward to buy the plant. Significantly changed circumstances created a Perfect Storm for Dominion Resources in the years 2010-2012 that led to an almost total elimination of Dominion's pre-tax earnings from

Figure C-1: Brayton Point's EBITDA (Earnings before Interest, Taxes, Depreciation and Amortization) 2009-2012



It appears almost certain that Dominion or any new owner, even if picking up Brayton Point at a bargain basement price, will likely not see gains that are sufficient to cover operating expenses, debt and an adequate return, for at least the rest of the decade.

the coal-burning Brayton Point Units 1-3 in Southeastern Massachusetts. These changed circumstances included plummeting energy market prices, declining capacity prices, increasing coal prices, a flattening of energy consumption in New England, and a steep reduction in the power generated at Brayton Point.

This near elimination of Brayton Point's earnings occurred in the very years that Dominion was completing a $1 billion upgrade at the once very profitable plant that included the addition of cooling towers and a scrubber system to reduce its SO2 and mercury emissions. Indeed, Dominion has decided to sell Brayton Point even though that will mean a loss of perhaps $700 million or more, of its recent $1 billion investment.

Moreover, looking forward from today, it appears almost certain that many of the factors that created the recent Storm will continue for the foreseeable future as Dominion or any new owner, even if picking up Brayton Point at a bargain basement price, will likely not see gains that are sufficient to cover operating expenses, debt and an adequate return, for at least the rest of the decade. Perhaps this is the very reason that Dominion has decided to sell Brayton Point and take such a large loss on its recent investments.

In particular, we have concluded that, based on today's forward looking circumstances, it is reasonable to expect that for the remainder of this decade, at least:

- Energy market prices in New England will remain low, reflecting continuing low natural gas prices.
- Energy consumption in New England will remain flat while consumption in Massachusetts may decline.
- Bituminous coal prices will not drop significantly.
- As a result, the generation at Brayton Point Units 1-3 is not likely to reach the high levels of performance achieved by the units through 2009.
- Future New England capacity prices are not likely to increase significantly.

As can be seen from Figures C-2 and C-3, we have examined two scenarios that differ in the levels of expected generation from Brayton Point Units 1-3. In what we have termed the "optimistic scenario," generation from the Units is expected to increase to 60 percent in the years 2018-2020. In the "less optimistic scenario," generation from Brayton Point Units 1-3 is projected to be capped at 40 percent through the years 2013-2020. We consider this to be a conservative assumption as it is quite possible that the generation from Brayton Point Units 1-3 will not increase as much as we assumed. Thus, in no way, did we examine a "worst-case" scenario in which the future operating performance of Units 1-3 would be at the same low 16 percent average capacity factor that the Units achieved in

2012. In other words, earnings from Brayton Point 1-3 could easily be even lower than we have projected. In neither of these scenarios, would Brayton Point Units 1-3 produce earnings that would be adequate to cover depreciation and amortization, debt costs and an adequate return at any time through 2020.

Figure C-2: Projected Brayton Point EBITDA, 2013-2020 – Optimistic Scenario

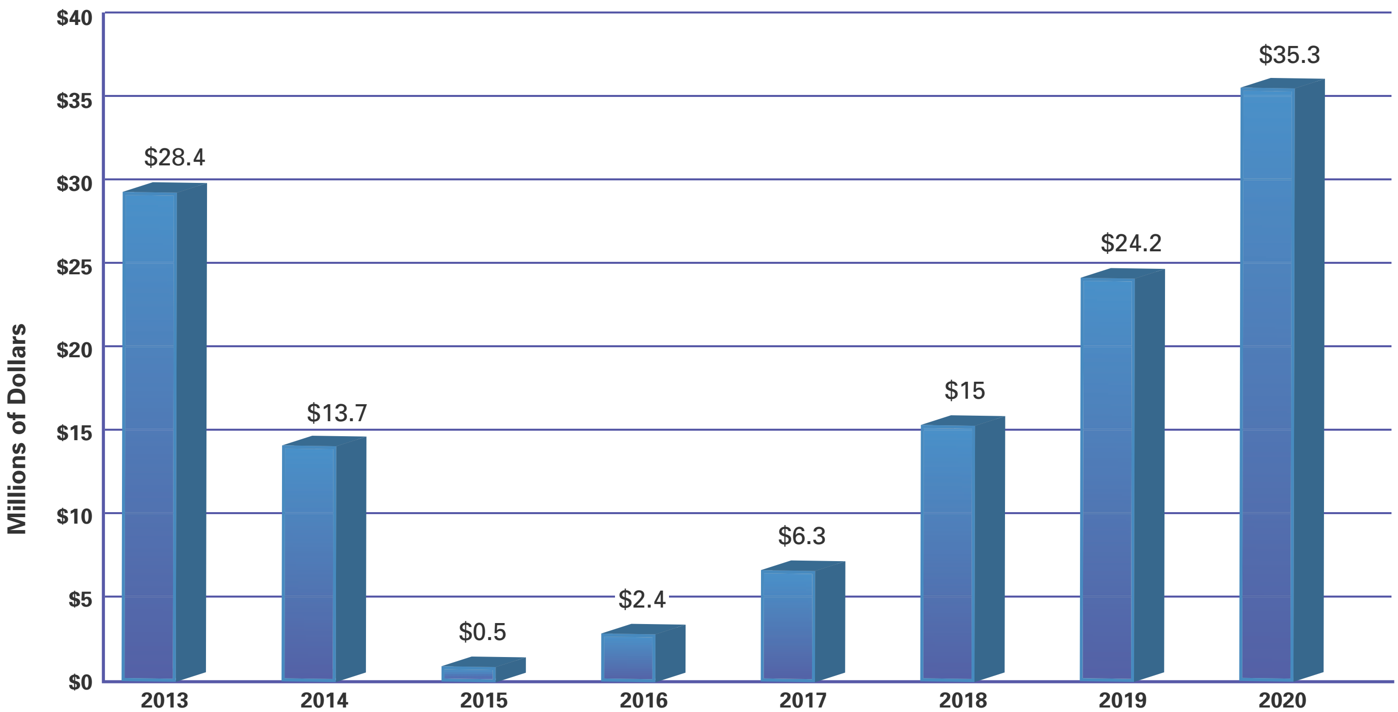


Table C-1: Projected Brayton Point EBITDA, 2013-2020, Optimistic Scenario

	2013	2014	2015	2016	2017	2018	2019	2020
Annual Capacity Factor (%)	30%	35%	40%	45%	50%	60%	60%	60%
Net Capacity	1100	1100	1100	1100	1100	1100	1100	1100
Annual Output (Thousands of MWh)	2,889	3,370	3,852	4,333	4,815	5,778	5,778	5,778
Energy Price ($/MWh)	$48.68	$46.85	$45.99	$45.99	$49.43	$51.68	$54.49	$57.67
Energy Margin ($Millions)	42	28	14	14	24	35	45	56
Capacity Revenue (Millions)	39	41	44	44	45	46	47	48
EBITDA ($Millions)	**28**	**14**	**1**	**2**	**6**	**15**	**24**	**35**

This same conclusion applies to Brayton Unit 4, which burns oil, as its costs of production are significantly higher than projected New England energy market prices.

Figure C-3: Projected Brayton Point EBITDA, 2013-2020 – Less Optimistic Scenario

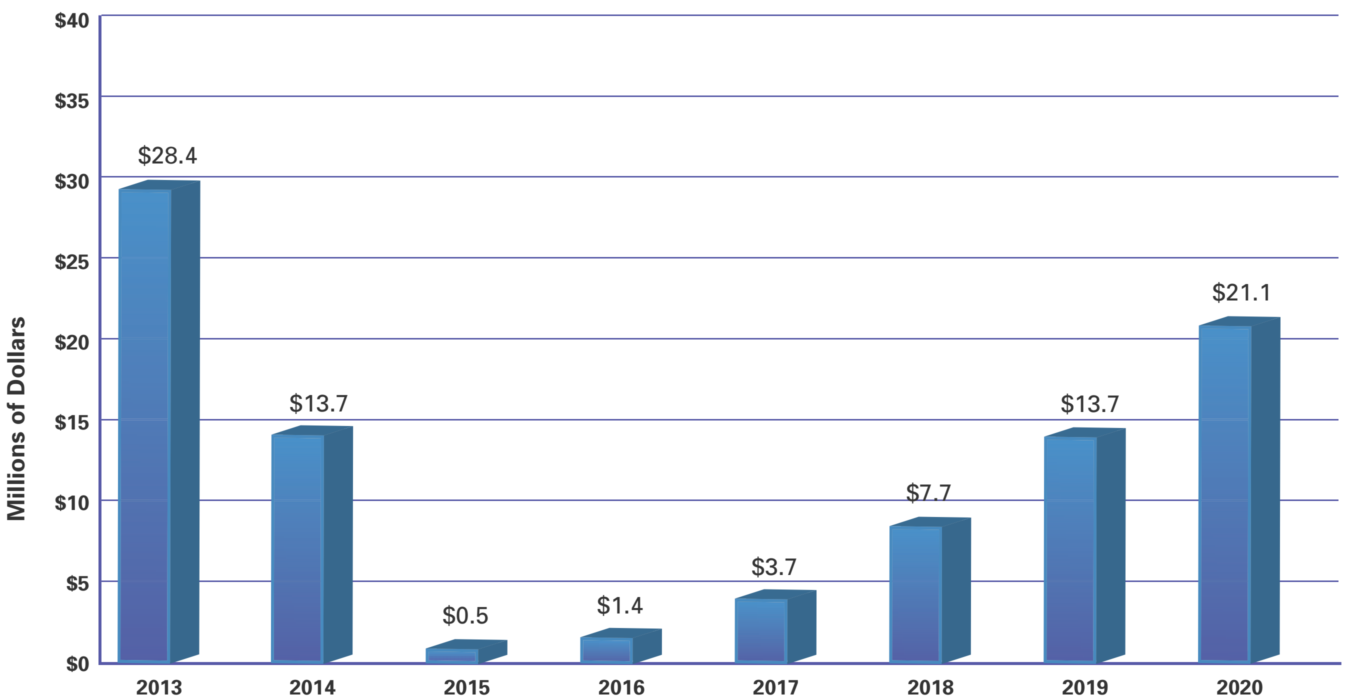


Table C-2: Projected Brayton Point EBITDA, 2013-2020, Less Optimistic Scenario

	2013	2014	2015	2016	2017	2018	2019	2020
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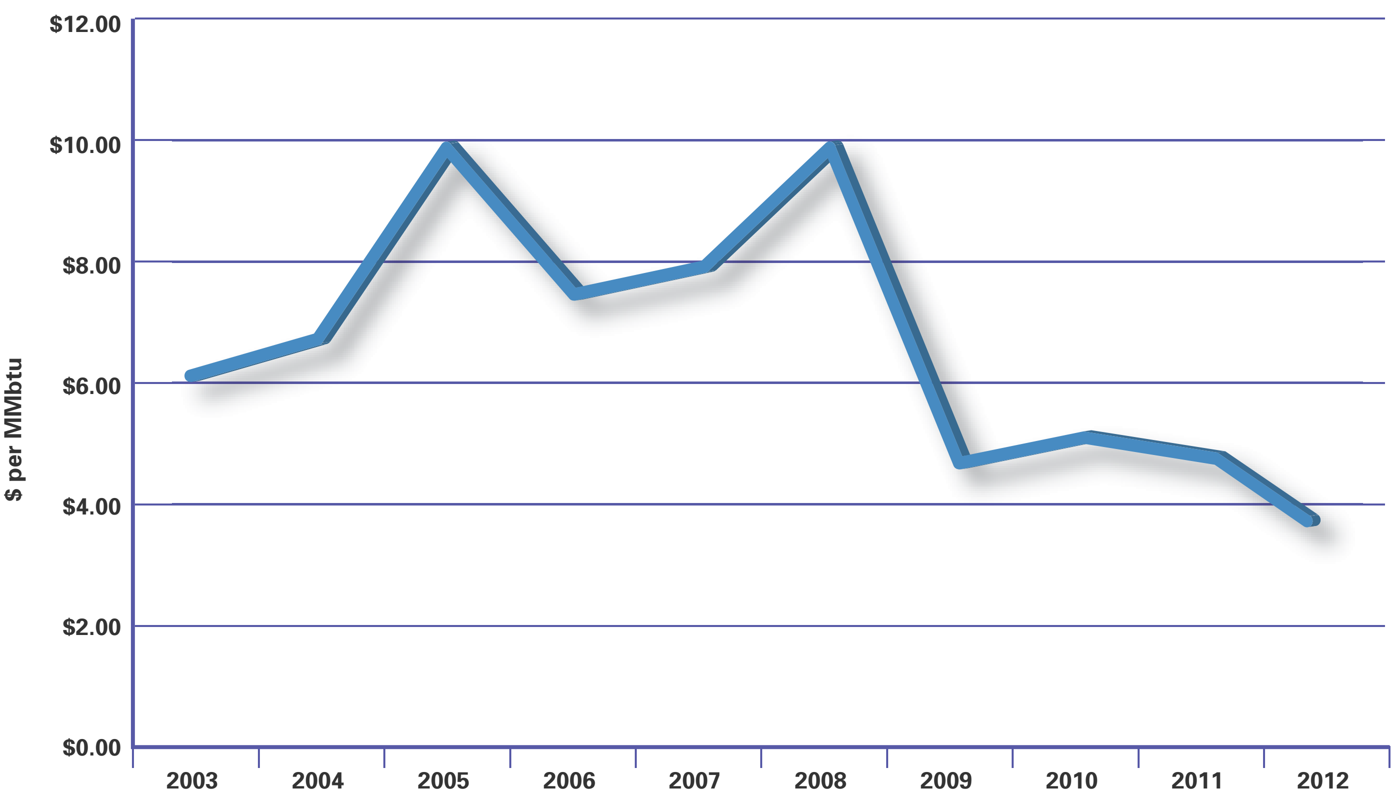
Energy Price ($/MWh)	$48.68	$46.85	$45.99	$47.66	$49.43	$51.68	$54.49	$57.67
Energy Margin ($Millions)	42	28	14	16	19	23	30	38
Capacity Revenue (Millions)	39	41	44	44	45	46	47	48
EBITDA ($Millions)	**28**	**14**	**1**	**1**	**4**	**8**	**14**	**21**

CHANGED CIRCUMSTANCES THAT HAVE CAUSED BRAYTON POINT'S EARNINGS TO PLUMMET SINCE 2009

The first, and most significant, changed circumstance that has reduced Dominion's earnings from the sale of power generated by Brayton Point Units 1-3 has been the collapse of natural gas prices that started in late 2008/early 2009. This rapid price decline was the result of the nearly universal recognition that the United States has substantial economically recoverable reserves that are accessible at production costs far below more traditional gas wells. Figure 1 shows the average natural gas prices in New England between 2003 and 2012 with a steep price drop between 2008 and 2009 and further erosion in prices through 2012.

Thus, average natural gas prices in New England in 2012 were some 32 percent lower than in 2003 and nearly 20 percent lower than they had been just the year before in 2011.[2]

Figure 1: Average Annual New England Natural Gas Prices 2003-2012



Natural gas has in recent years increasingly been the marginal fuel in ISO-NE, rising from being the marginal fuel in 68 percent of the pricing intervals in the twelve month period ending September 30, 2011 to 82 percent of the pricing intervals in the twelve month period ending September 30, 2012. Natural gas-fired units have thereby increasingly set energy market prices.

Thus, it is not a surprise that ISO-NE's wholesale electricity prices have decreased almost in tandem with dropping natural gas prices. Figure 2, then shows a steep decline in average wholesale electricity prices in ISO-NE from 2003 through 2012 (energy prices only) that reflects the sharp drop in natural gas prices shown in Figure 1.

These lower energy market prices and reduced energy margins have meant both reduced revenues for coal plant owners, like Dominion Resources, and reduced generation at coal-fired power plants, like Brayton Point, as coal has been increasingly displaced by natural gas-fired generation.

Figure 2: Average New England Wholesale Electricity Prices 2003-2012 (Energy Market Only)

The recent displacement of coal by gas-fired generation in New England is shown clearly in Figures 3 and 4, which present the percentages of ISO-NE's generation from natural gas (Figure 3) and coal (Figure 4) each quarter from January 2010 through September 2012. As can been seen, natural gas's contribution to ISO-NE's generation has been increasing in each quarter as compared to the same quarter in the previous year while coal's contribution has been declining steadily.

Figure 3: Natural Gas as a Percentage of ISO-NE's Generation by Quarter in 2010-2012

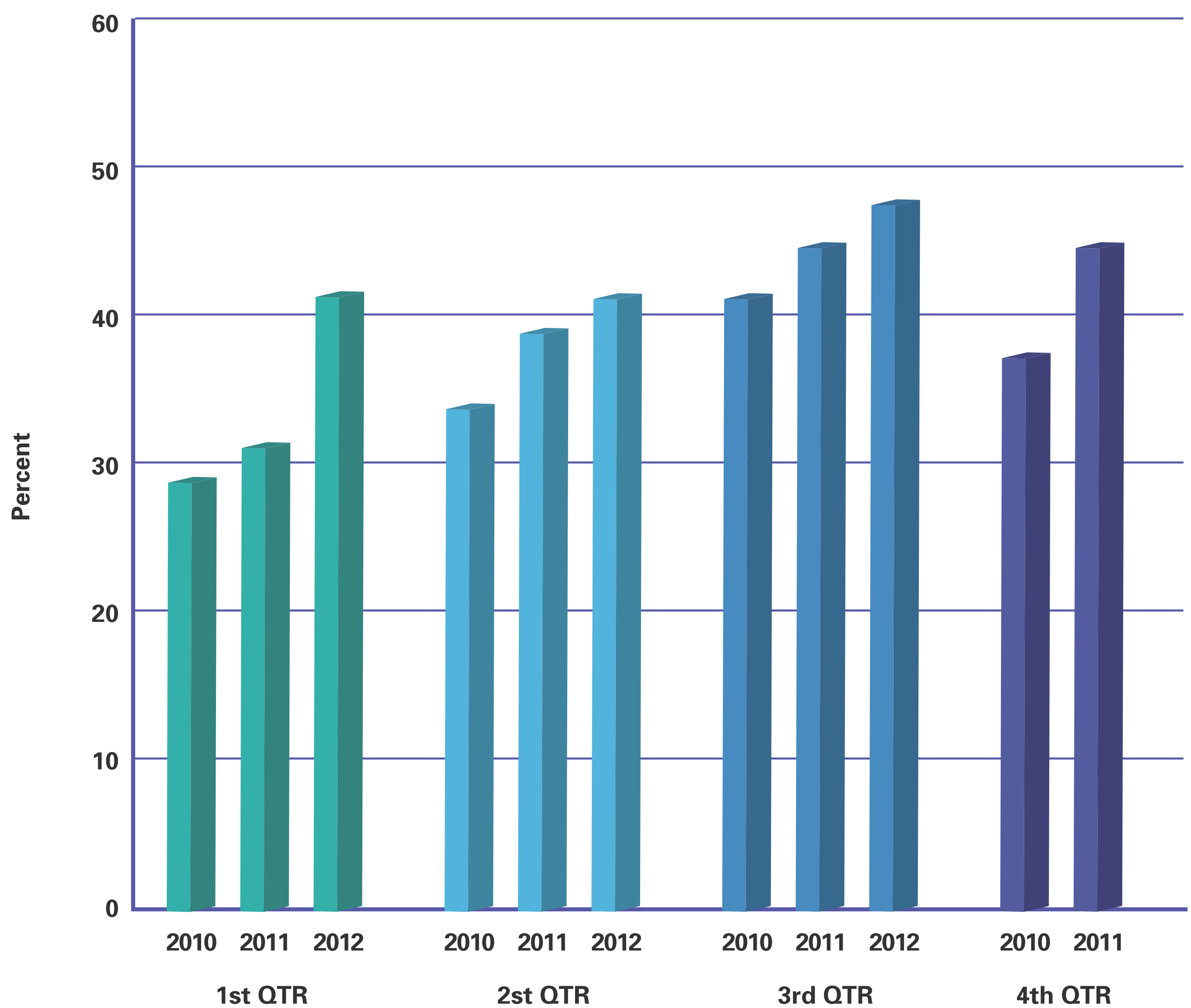
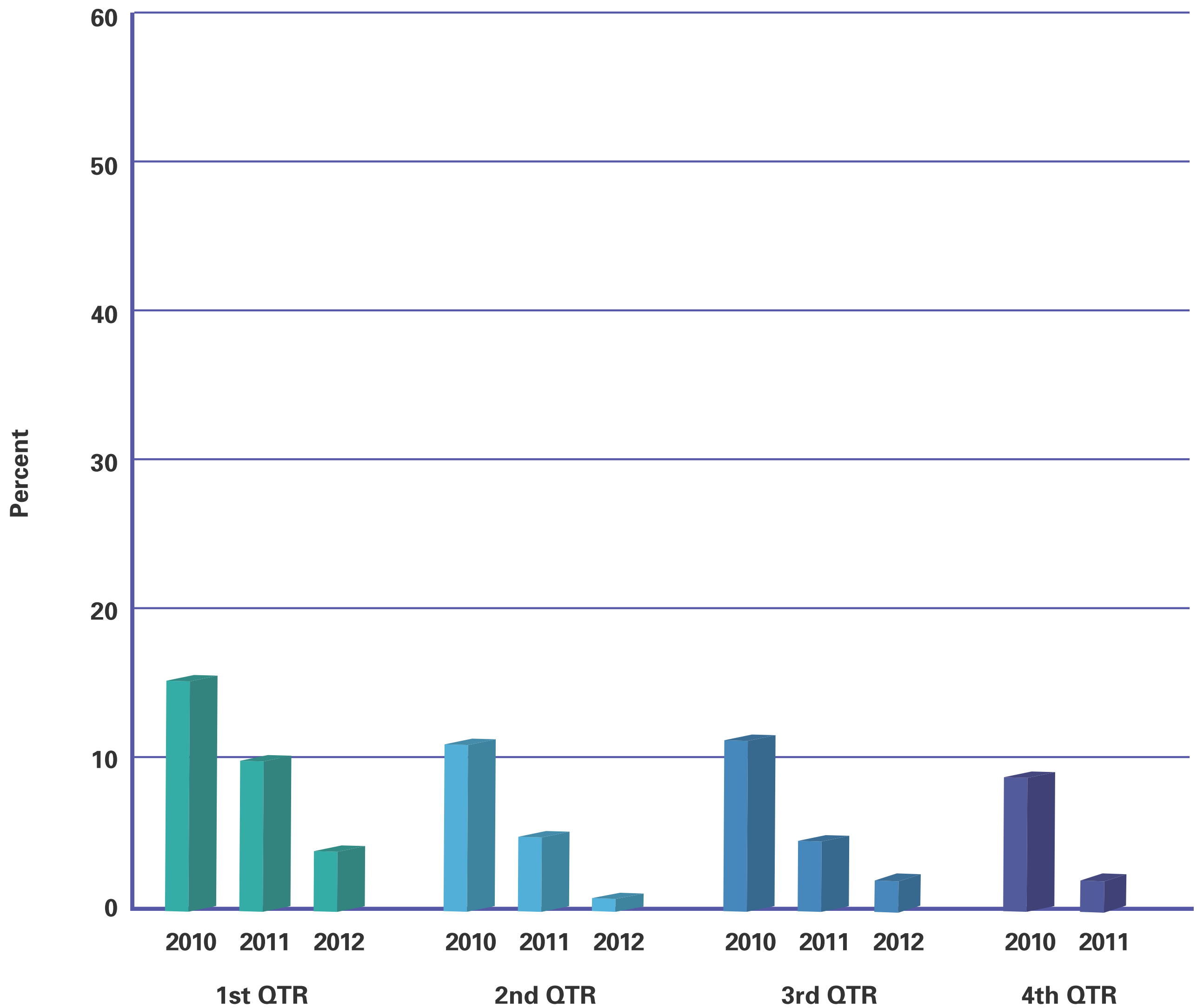


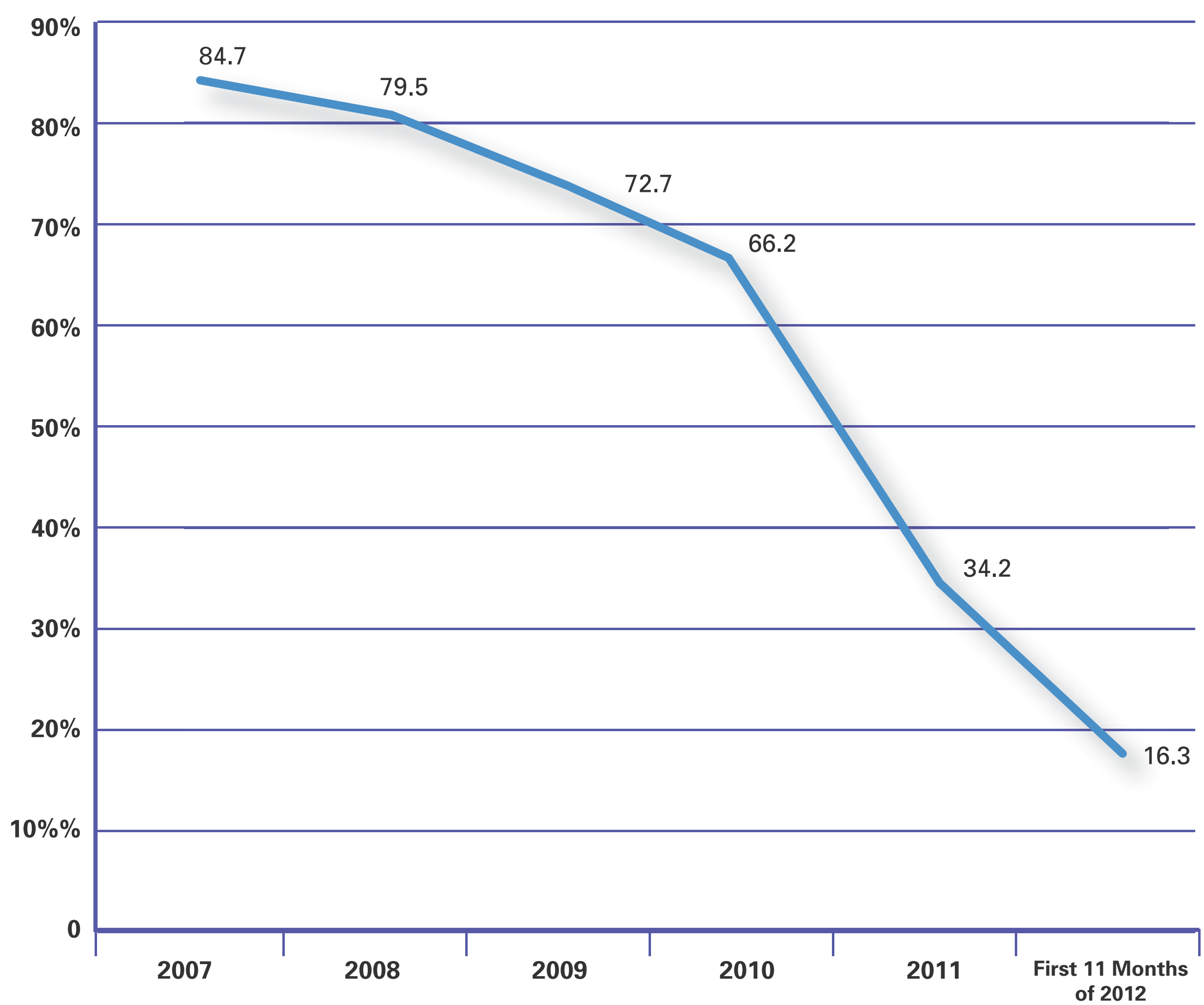
Figure 4: Coal as a Percentage of ISO-NE's Generation by Quarter in 2010-2012



These lower energy market prices and reduced energy margins have meant both reduced revenues for coal plant owners, like Dominion Resources, and reduced generation, like Brayton Point.

Given coal's sharply declining share of ISO-NE generation, it is no surprise that Brayton Point's generation has declined significantly in recent years, as is shown in Figure 5.

Figure 5: Annual Brayton Point Capacity Factors 2008-2012



Moreover, at the same time that natural gas prices have declined significantly, there has not been a similar drop in the delivered prices of the Central Appalachian coal that is burned at Brayton Point, as is shown in Figure 6. In fact, the delivered coal prices increased significantly from 2008 through 2011 before decreasing between 2011 and 2012.

While ISO-NE's energy market prices were declining in recent years, its capacity prices also have been declining with a 35 percent decrease in the price obtained in the Forward Capacity Auction for capacity in 2012 as compared to the price for 2010. Figure 7 shows the results of ISO-NE's first six forward capacity auctions for the periods June 2010 through May 2016.

Dominion mitigated the effects of the declining energy market prices and capacity prices, and protected its earnings, by hedging its sales through selling energy and capacity at forwards prices. For example, Dominion's 4th Quarter 2010 Earnings Report noted that 100 percent of the output from the Company's New England Baseload plants (i.e., Millstone, Brayton Point and Salem Harbor) during

Figure 6: Brayton Point Average Delivered Coal Prices 2008-2012

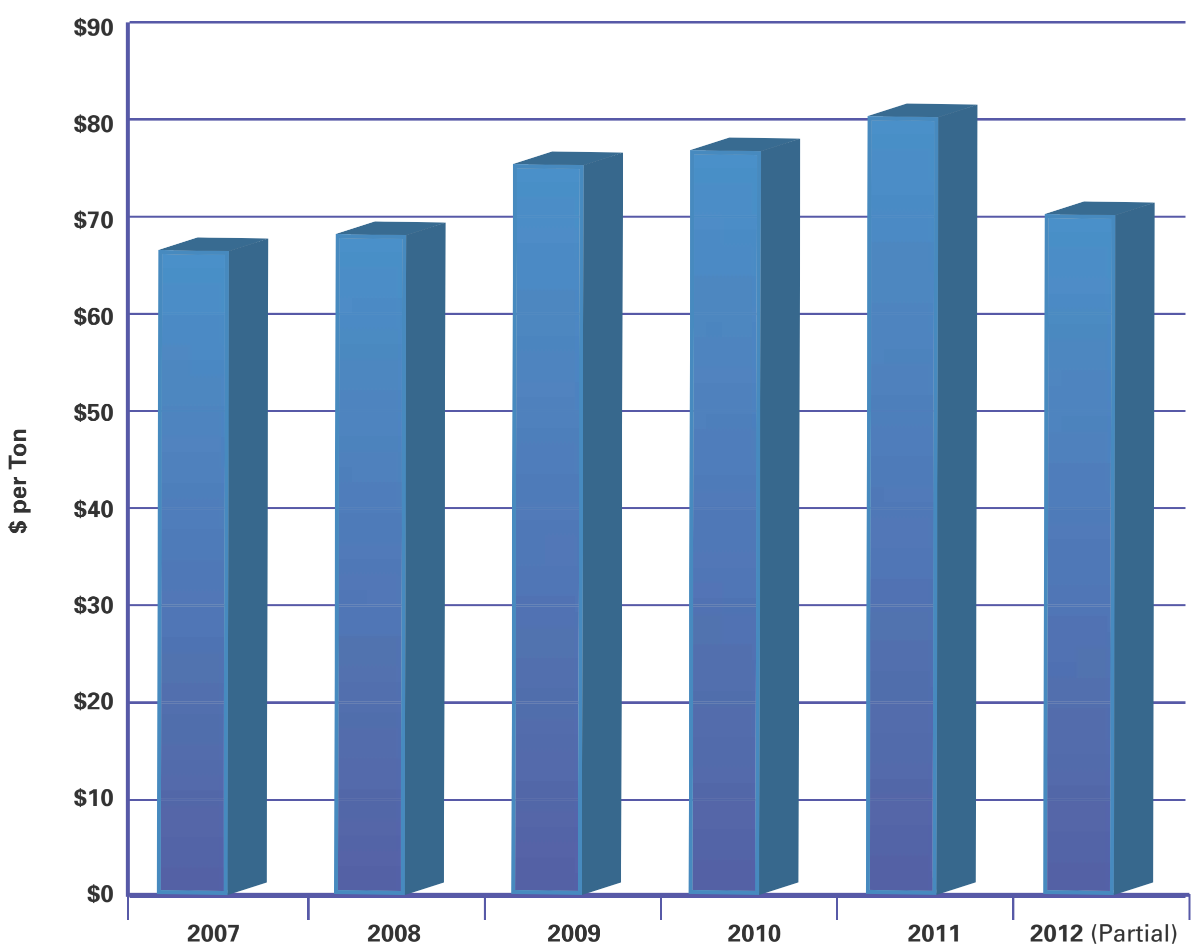


Figure 7: ISO-NE Forward Capacity Market Results (kW-Month)

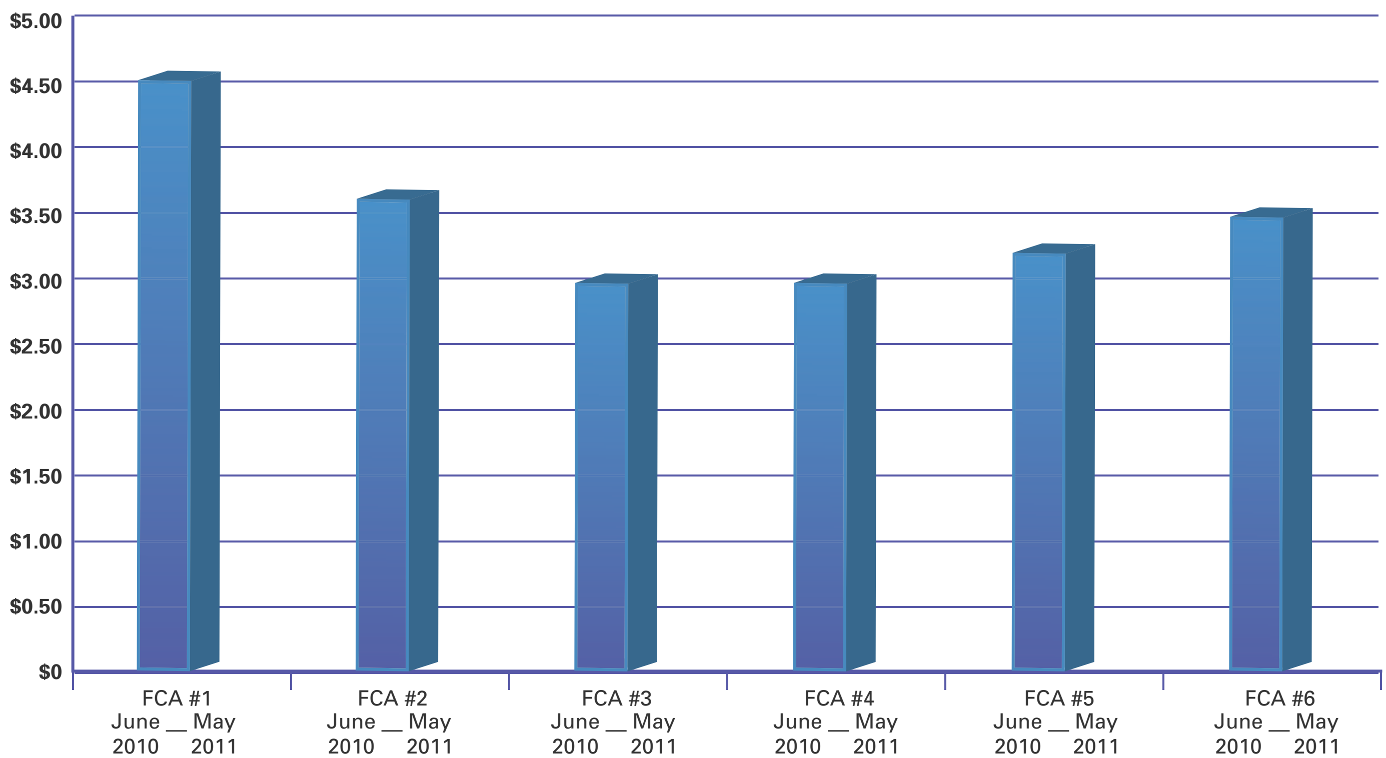
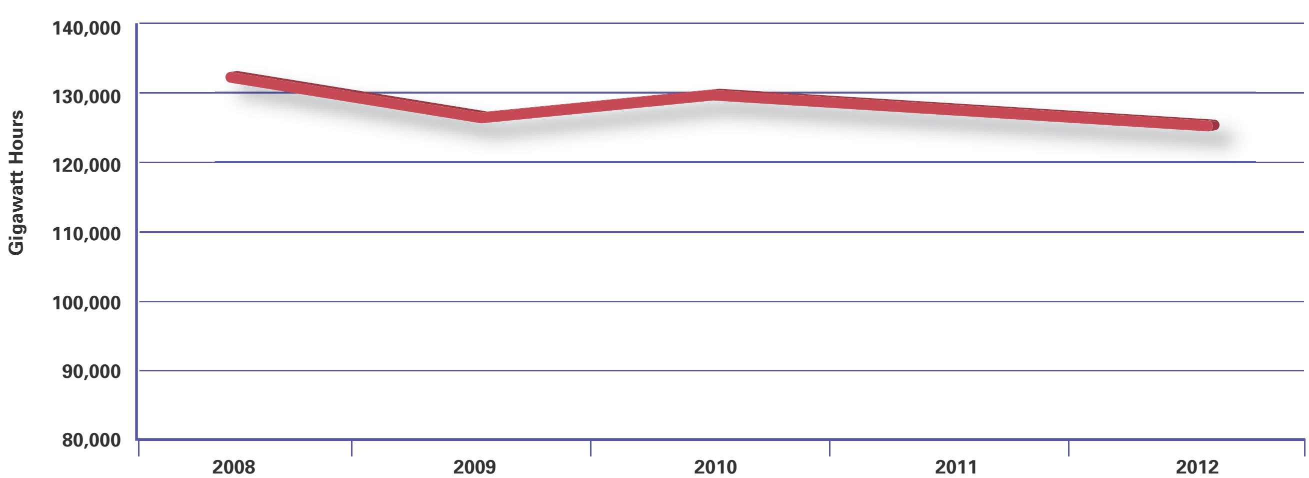


Figure 8: Weather Adjusted ISO-NE Energy Usage from 2008 to 2012.



that quarter was hedged at an average price of $69.90 per MWh as compared to an average Massachusetts Hub/ New England price of $48.49 per MWh. However, as time went on, the benefits of hedging with forwards prices have diminished, if not entirely disappeared.

Moreover, at the same time that energy market prices and capacity prices were declining, energy usage in ISO-NE decreased by 2-3 percent between 2008 and 2012 as a result of the economic downturn and increasing energy efficiency efforts. This decline is shown in Figure 8.

ISO-NE's annual peak loads also decreased slightly during these same years.

As a result of these significantly changed circumstances, the earnings (as measured by EBITDA) from the sale of power generated at Dominion's New England Merchant Fleet, in general, fell significantly and disappeared almost entirely for Brayton Point Units 1-3, specifically, during the years 2009-2012, as shown in Figures 9 and 10.

New England Merchant Fleet declined, the Company's EBITDA from Brayton Point Units 1-3 cratered, dropping from a very healthy $345 million in 2009 to a very anemic $24 million in 2012.

The New England Fleet declined the sources of the data used in the analyses shown in Figures 9 and 10 were Company documents (particularly, Quarterly Earnings Reports), data from SNL Financial and ISO-NE documents.

Figure 9: Dominion New England Merchant Fleet EBITDA 2009-First Six Months of 2012 [3 4]

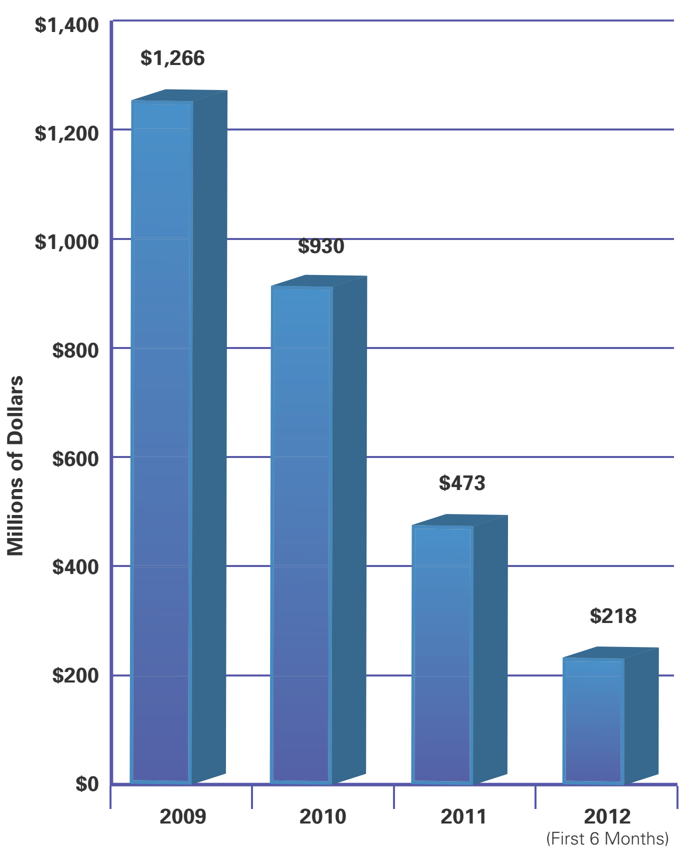
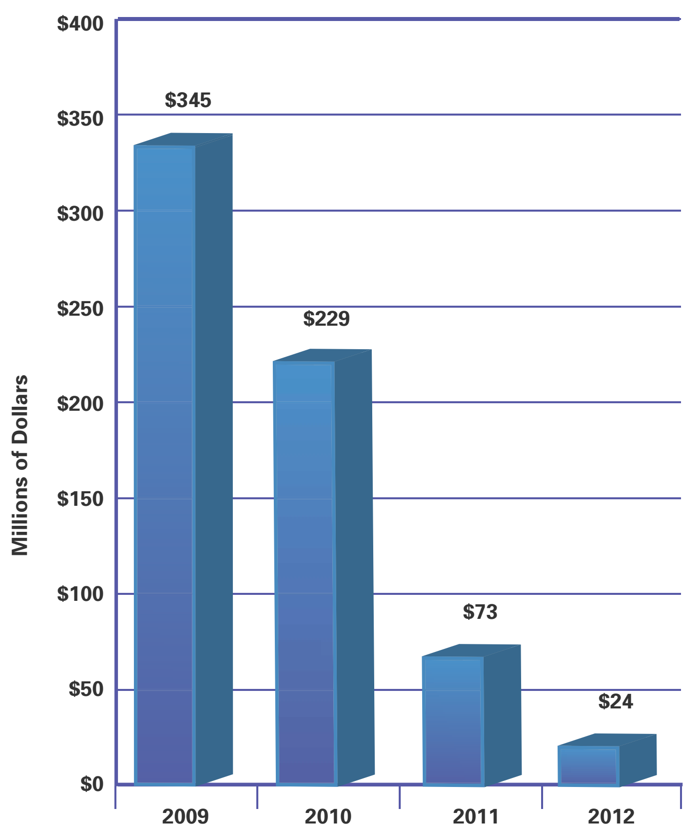


Figure 10: Brayton Point EBITDA, 2009-2012



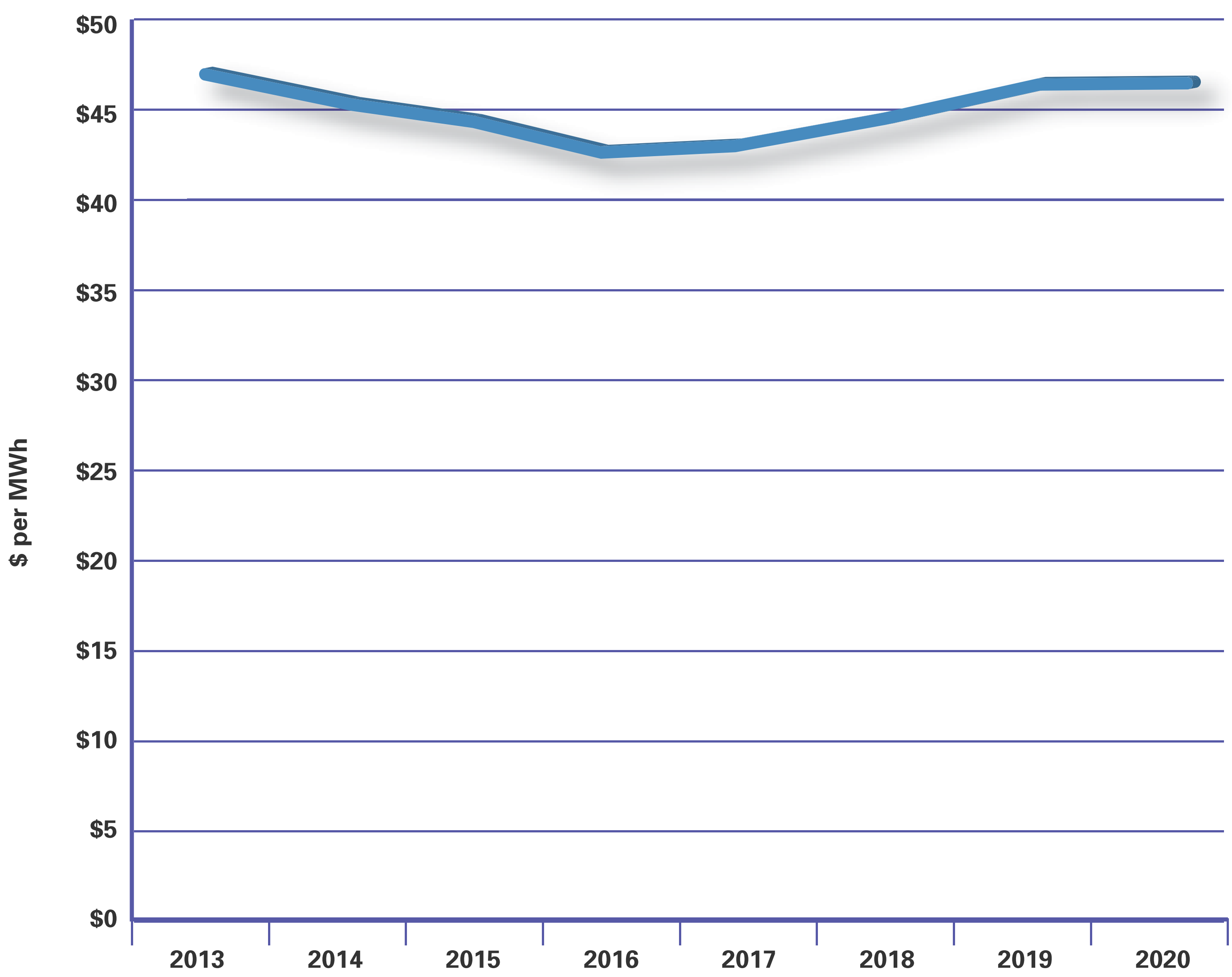
THE FUTURE PROFITABILITY OF POWER FROM BRAYTON POINT UNITS 1-3

In order to significantly improve the earnings from owning and operating Brayton Point, and to be able to pay the interest and profits on invested funds, the plant's owner will need some combination of higher revenues from increased energy market prices, capacity prices and plant generation and lower costs—which would be hoped for from lower coal prices although some savings in non-fuel O&M expenses are theoretically possible. However, from today's perspective, it is unlikely that future energy market prices, ISO-NE capacity market prices, plant generation and coal prices will lead to earnings high enough to provide both adequate recovery of Brayton Point's likely purchase price (through depreciation) and a good return on that investment.

Future Energy Market Prices

Recent energy market futures prices for ISO-NE actually show further declines in the next few years without any significant increases over 2012 prices through the rest of the decade. This is consistent with natural gas prices forwards which also show no significant increases for the next 5-7 years.

Figure 11: Energy Futures Prices for ISO-NE



In fact, concerns about natural gas supply security have led FERC and ISO-NE to begin to discuss possible proposals that could lead to expansion of pipeline capacity into New England. As explained by UBS Investment Research, a notable secondary effect of further pipeline capacity expansions would be additional depression of natural gas prices in New England which would further erode regional market power prices.[5] This would certainly further disadvantage Brayton Point's economic viability.

Future Capacity Prices

As shown in Figure 7 (p. 14), the results of ISO-NE's recent Forward Capacity Auctions do not show much recovery through 2016 from the substantial price decreases experienced between the auctions for 2010/2011 and 2012/2013. Moreover, FERC's mandate that the price floor be removed from future Capacity Auctions has led UBS Investment Research to expect a bust in future capacity markets and for a "sharp downtick in capacity [price] to drive economic retirements" of legacy oil-fired units in New England and much of the remaining coal capacity.[6] UBS also expects that new market designs under consideration by ISO-NE (targeted for implementation in the 2018/2019 auction) would put a preference on payments for flexible units (such as new combined cycle plants) at the expense of less flexible units. Such a preference, if/when implemented, would further disadvantage legacy steam units like those at Brayton Point, which are rather inflexible in comparison to the predominant newer natural gas-fired units in New England.

Future ISO-NE Loads and Energy Consumption

Any owner of Brayton Point cannot rely on future growth in regional energy usage as the basis for any significant increases in plant generation and revenue. ISO-NE recently released new forecasts that show relatively flat energy consumption in New England through 2021 with a modest decrease in energy consumption in Massachusetts. Instead, Brayton Point will have to compete with low cost natural gas-fired units and new renewable resources.

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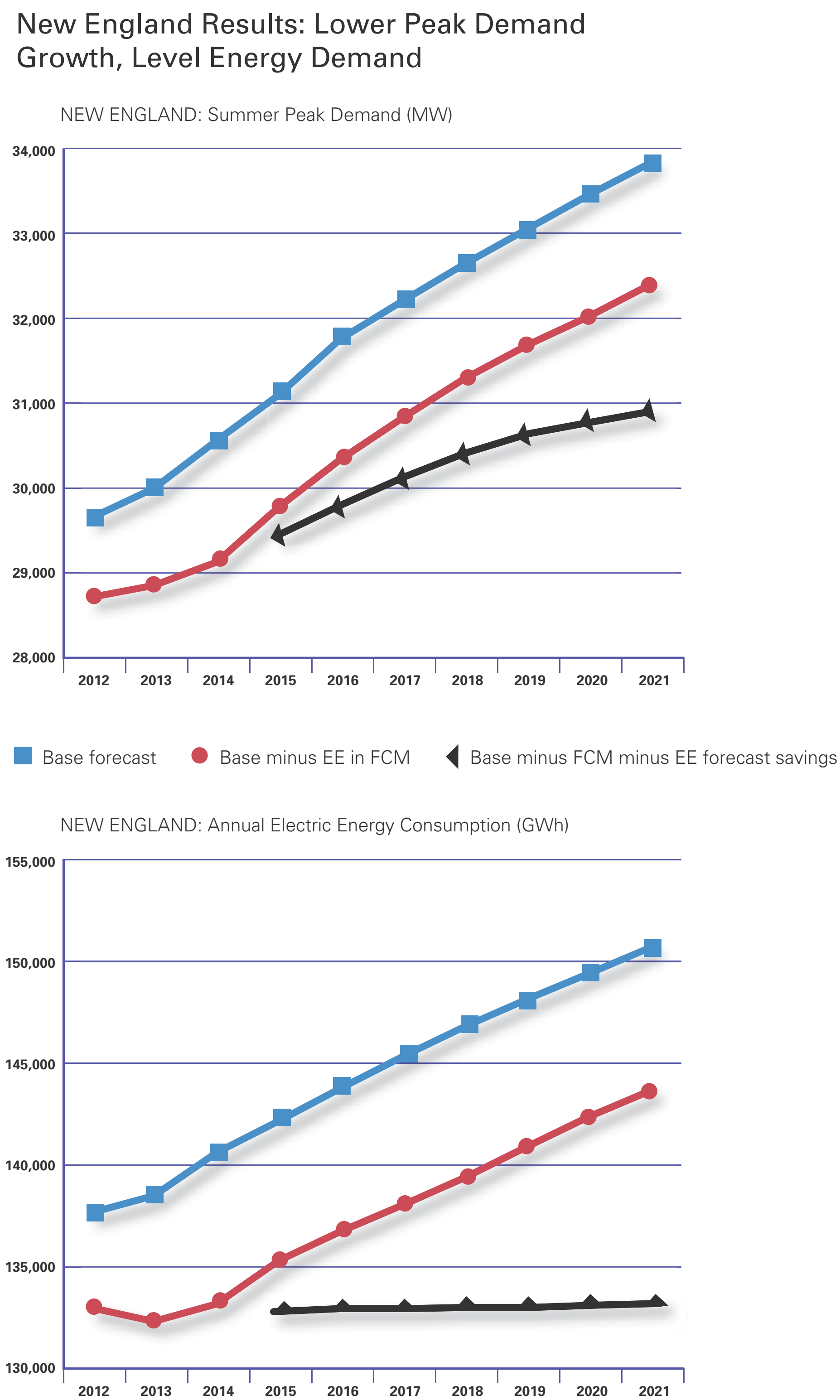
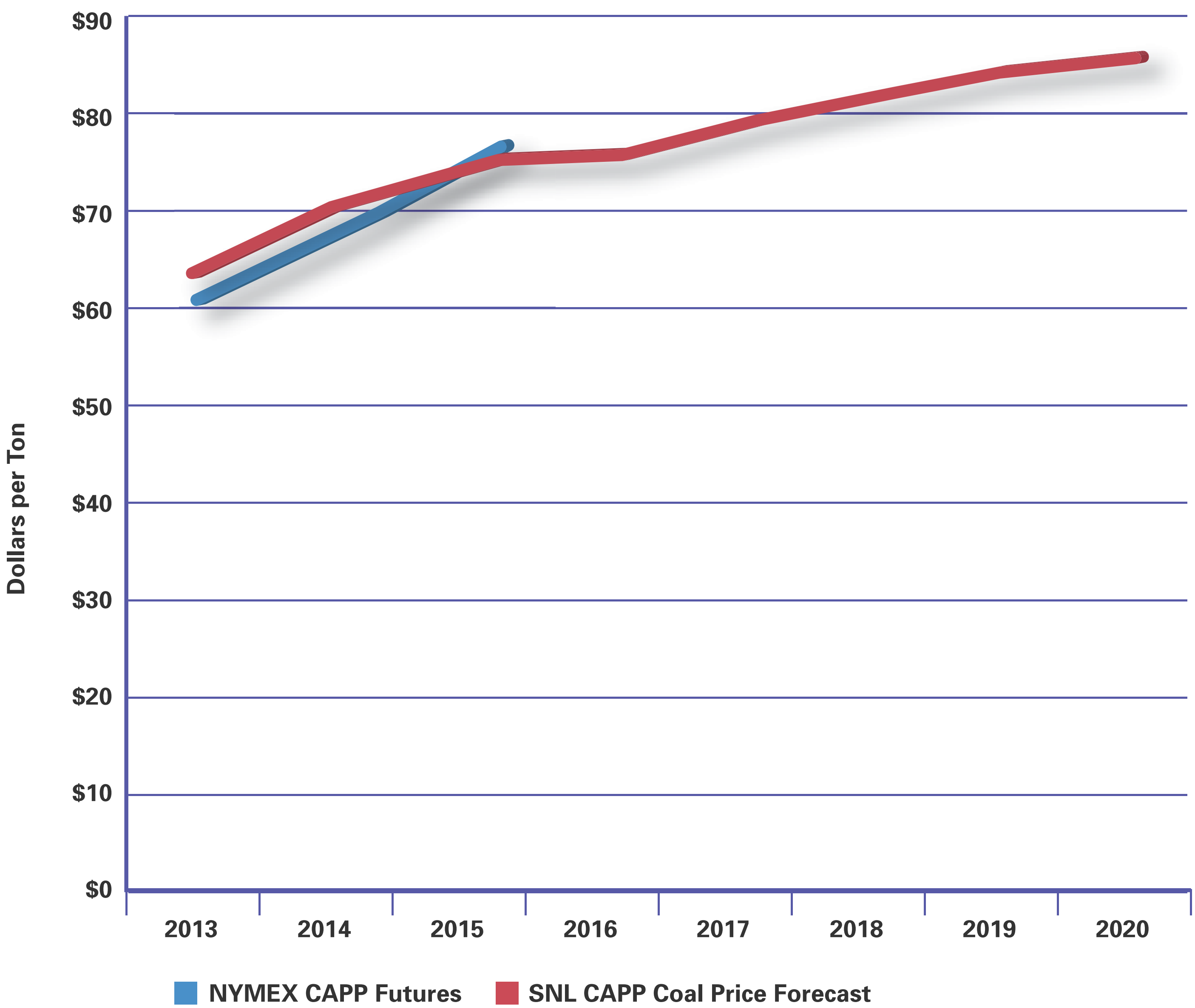
Figure 12: ISO-NE Energy Efficiency Forecast for New England, December 2012



Coal Prices

Brayton Point has recently burned bituminous coal from Central Appalachia ("CAPP") mixed with limited amounts of coal imported from mines in Columbia, South America. The currently low market prices that now exist at this time of declining demand for CAPP coal are unsustainable. Elevated production costs in the region, historically high transportation costs to the Northeast corridor as well as the supply and price dynamics of international markets place upward pressure on the amount a coal producer from the region must charge utility buyers. It is unlikely that the owner of Brayton Point will achieve delivered coal prices over the project period that are below, let alone significantly below, recent projections of future CAPP coal prices.

Figure 13: Recent NYMEX Futures as of 2-1-2013 and SNL Forecast of CAPP Coal Prices

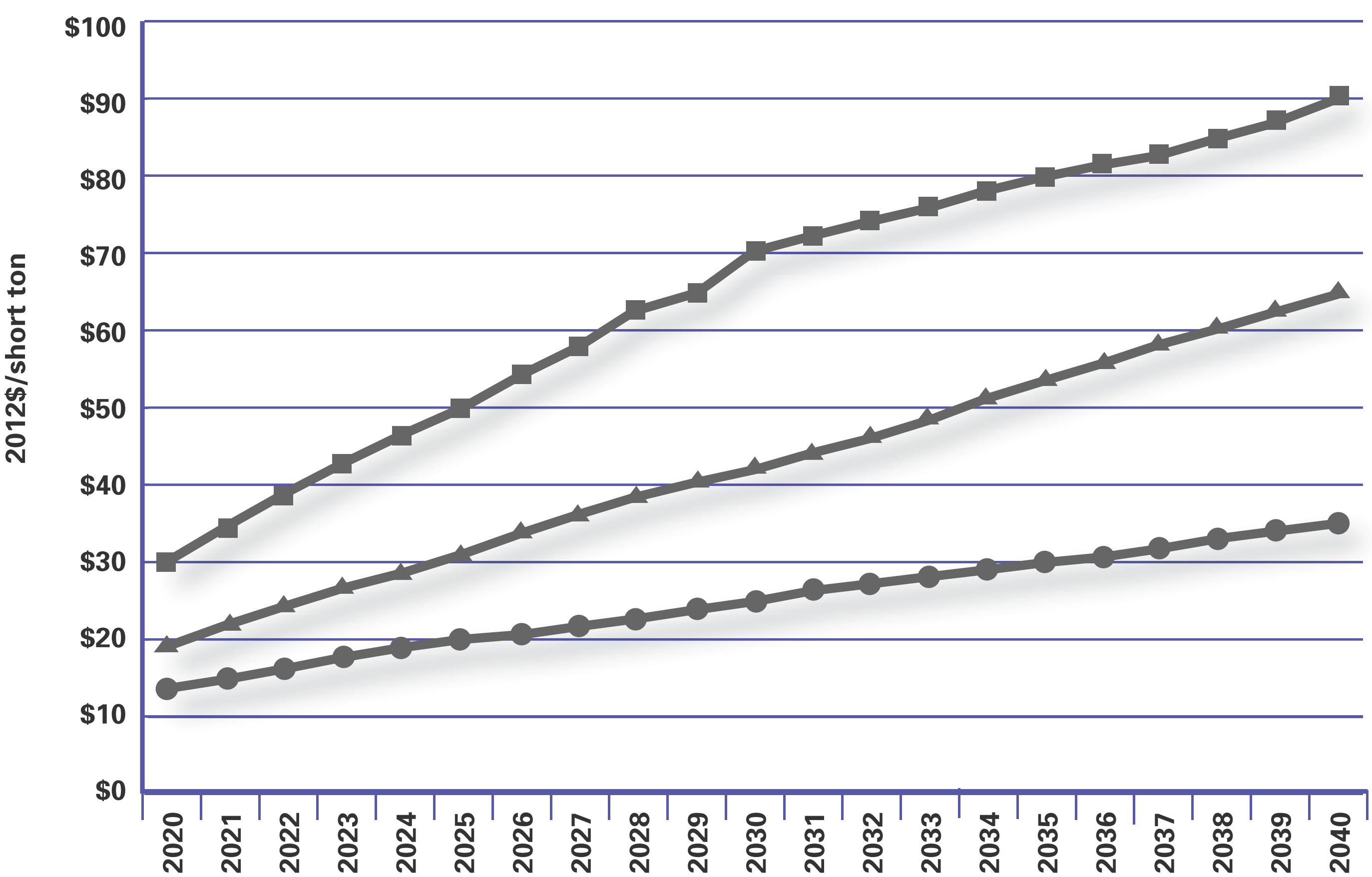


Carbon (CO2) Prices

Under the Regional Greenhouse Gas Initiative ("RGGI") generators in New England already must pay for carbon dioxide allowances, at a current rate of $1.93 per ton. However, there are several measures that have the potential to adversely impact the future economics of selling the power from Brayton Point Units 1-3. These measures include:

- The ongoing redesign of the RGGI program with a reduced emissions target of 91 million tons of CO2 will increase costs of fossil-fired generators. As explained by UBS Investment Research, this redesign, which is tentatively being considered for implementation by 2014, could translate to a $3-4 per ton cost for CO2 emissions which would mean a $3-4 per MWh cost for coal generation and a $1-$2 per MWh cost for gas generators.[7]
- The U.S. Environmental Protection Agency is working on a New Source Performance Standard for existing sources, such as coal-fired power plants like Brayton Point. Although the design of this existing source standard is still under consideration, it is possible that it would be efficiency-based like the NSPS for new sources. It is anticipated that the proposed NSPS for existing sources could be issued for comment in late 2013 or 2014 with widespread implementation in 2019 or 2020.[8]
- Given the increasing public recognition and concern over climate change, it is reasonable to expect that there will be a legislative program at some point in the not-too-distant future that will place a significant price on greenhouse gas emissions from fossil-fuel-fired power plants. Although the timing, design and stringency of such a comprehensive federal regulatory regime are unknown, we believe that the following CO^2

Figure 14: Synapse Energy Economics 2012 Carbon Dioxide Price Forecast[9]



> price forecasts from Synapse Energy Economics offer a reasonable set of prices that should be considered in resource planning and related economic evaluations. This is especially true where, as here, the power plant burns coal, the most carbon intensive fuel.

The three CO^2 price trajectories shown in the Synapse price forecast reflects the great uncertainty in the timing, design and stringency or any comprehensive federal greenhouse gas regulatory regime.

Age-Related Risks

Brayton Point Units 1, 2 and 3 are 50, 49 and 44 years old in 2013, respectively. Given these ages, despite Dominion Resources recent investment of nearly $1 billion in a new scrubber and cooling towers, there is significant uncertainty about their future operating performance and costs. In fact, no coal unit of 100 MW or larger has operated for more than 65 years and only a few smaller units have operated longer.

Therefore, there is great uncertainty about (a) what the units' operating lives will be, (b) what additional capital investments will be required as they age, (c) what their operating performance will be as they age (in terms of generation, planned and forced outage rates, availability and equivalent forced outage rates), and (d) what their operating costs will be as they age.

Indeed, the more than two hundred coal units that had been retired through the end of 2012 had an average age at retirement of 51 years, with a median age of 53 years when they were retired. The 105 other coal units with announced retirement dates of 2013 or later, will have an average age at retirement of 57 years, with a median age of 60 years.

CONCLUSION CONCERNING FUTURE EARNINGS FROM BRAYTON POINT UNITS 1-3

Given all of the factors discussed above, it is unlikely that Dominion or any new owner can expect to obtain earnings sufficient to cover operating expenses, debt and an adequate return from Brayton Point Units 1-3 at least until after 2020, at which time the plant might be subject to significant CO^2 emissions costs.

As can be seen from Figures 15 and 16, we have examined two scenarios that differ in the levels of expected generation from Brayton Point Units 1-3. In what we have termed the "optimistic scenario," generation from the Units is expected to increase to 60 percent in the years 2018-2020. In the "less optimistic scenario," generation from Brayton Point Units 1-3 is projected to be capped at 40 percent through the years 2013-2020. We consider this to be a conservative assumption as it is quite possible that the generation from Brayton Point Units 1-3 will not increase as much as we assumed. Thus, in no way, did we examine a "worst-case" scenario in which the future operating performance of Units 1-3 would be at the same low 16 percent average capacity factor that the Units achieved in 2012. In other words, earnings from Brayton Point 1-3 could easily be even lower than we have projected in Figures 15 and 16. In neither of these scenarios, would Brayton Point Units 1-3 produce earnings that would be adequate to cover depreciation and amortization, debt costs and an adequate return at any time through 2020.

These annual EBITDA will be inadequate to cover the amortization of the purchase price for Brayton Point if it is sold, let alone provide the funds to pay for annual interest costs and any return for equity investors.

The analysis presented in Figures 15 and 16 and Tables 1 and 2 is based on information from SNL Financial, NYMEX futures prices, and data from the ISO-NE website. It reflects only energy and capacity revenues, assuming that any other auxiliary revenues that Brayton Point receives from the ISO-NE markets are offset (and perhaps more than offset) by the costs of purchasing emissions allowances.

The analysis also reflects the following other conservative assumptions:

- A rapid recovery in Brayton Point's generation from the 16 percent capacity average factor the Units achieved in 2012 to a 30 percent capacity factor in 2013 with higher capacity factors in subsequent years.
- Current futures for ISO-NE energy market prices through 2015 with market prices escalated after 2015 at the same escalation rate as Henry Hub natural gas futures.

Figure 15: Projected Brayton Point EBITDA, 2013-2020 – Optimistic Scenario

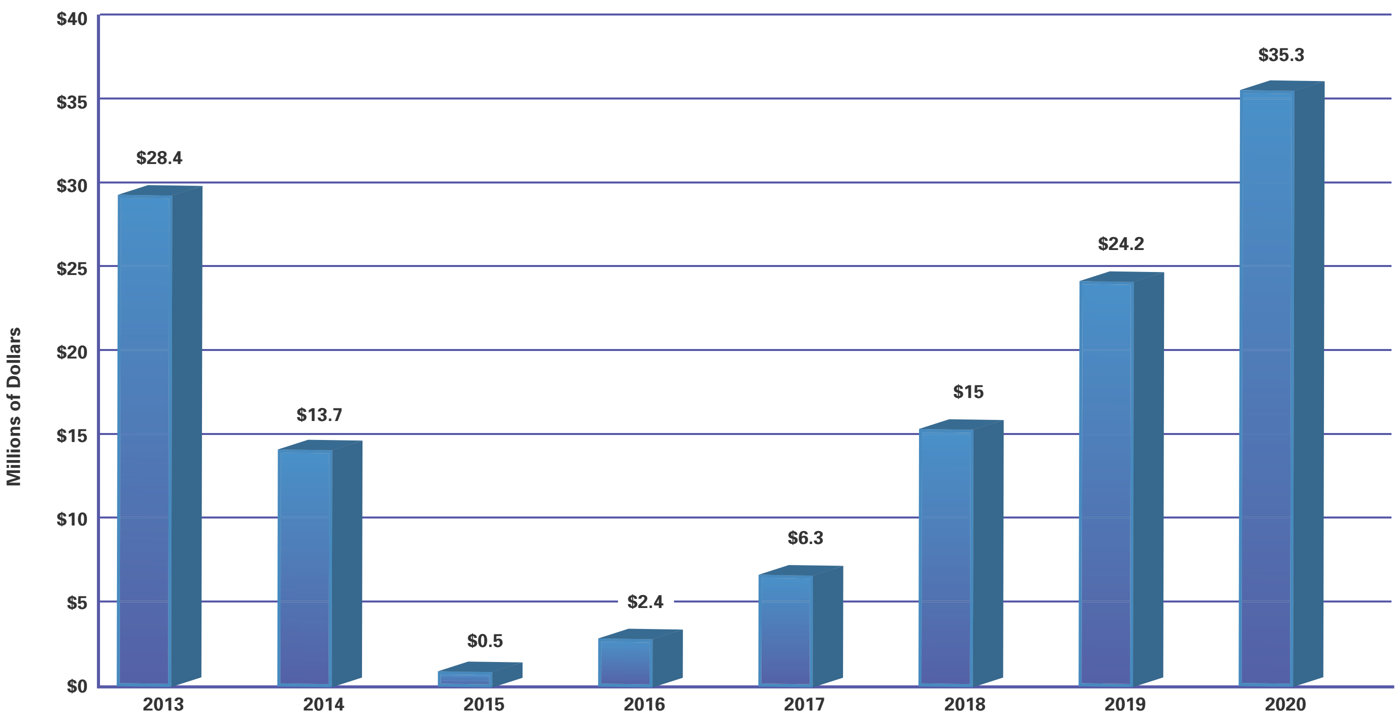


Table 1: Projected Brayton Point EBITDA, 2013-2020, Optimistic Scenario

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Capacity Revenue (Millions)	39	41	44	44	45	46	47	48
EBITDA ($Millions)	28	14	1	2	6	15	24	35

- The results of ISO-NE's forward capacity auctions through May 2016 with the prices escalated in subsequent years at a 2.5 percent annual overall rate of inflation.
- A modest decrease in the Units' net MW output and plant efficiency and increase in non-fuel O&M to reflect the addition of the new cooling towers and SO2 scrubber.

Figure 16: Projected Brayton Point EBITDA, 2013-2020 – Less Optimistic Scenario

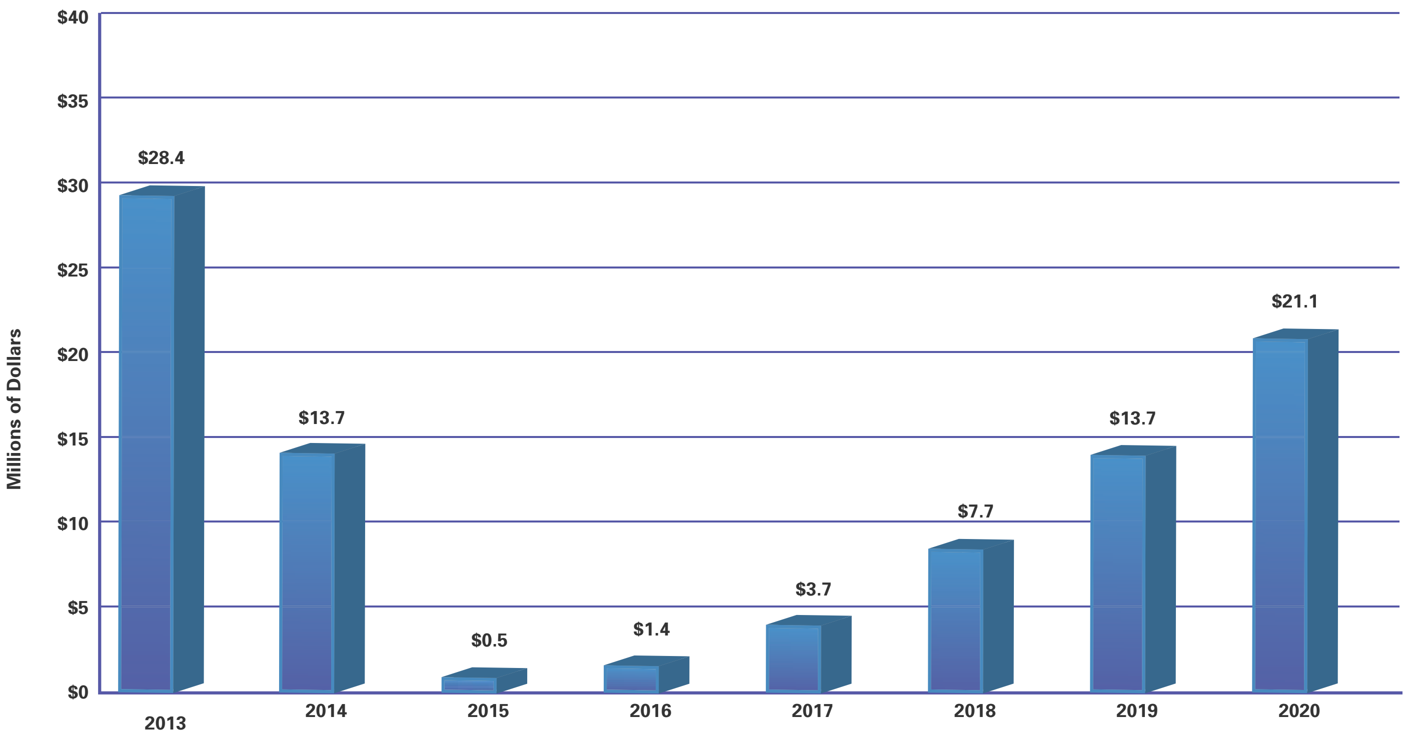


Table 2: Projected Brayton Point EBITDA, 2013-2020, Less Optimistic Scenario

	2013	2014	2015	2016	2017	2018	2019	2020
Annual Capacity Factor (%)	30%	35%	40%	40%	40%	40%	40%	40%
Net Capacity	1100	1100	1100	1100	1100	1100	1100	1100
Annual Output (Thousands of MWh)	2,889	3,370	3,852	3,852	3,852	3,852	3,852	3,852
Energy Price ($/MWh)	$48.68	$46.85	$45.99	$47.66	$49.43	$51.68	$54.49	$57.67
Energy Margin ($Millions)	42	28	14	16	19	23	30	38
Capacity Revenue (Millions)	39	41	44	44	45	46	47	48
EBITDA ($Millions)	28	14	1	1	4	8	14	21

- Overall non-fuel O&M costs increase at the 2.5 percent annual overall rate of inflation.
- A recovery of coal prices in 2013 to 2011 levels with escalation from 2013 to 2015 at the same rate as NYMEX CAPP futures and at 2.5 percent per year after 2015, a very conservative assumption.

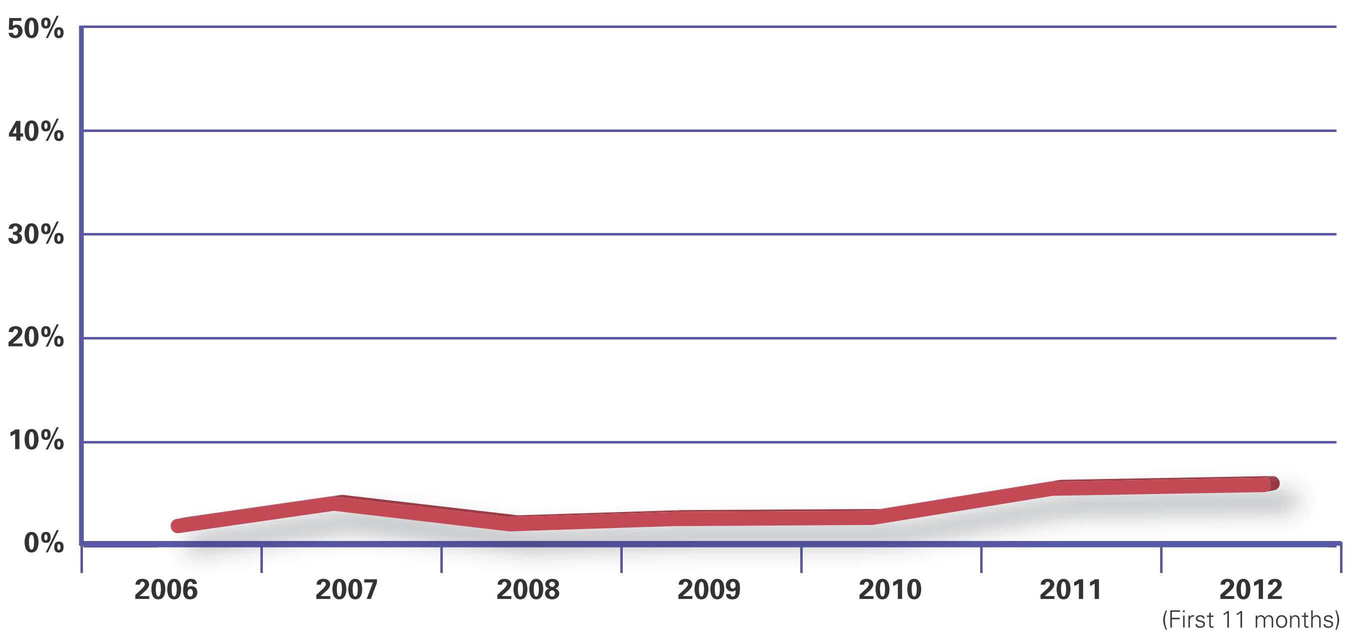
BRAYTON POINT UNIT 4

Brayton Point Unit 4 is a 435 MW (net) oil-fired generating unit. It has generated very little power in recent years, with average annual capacity factors of between 1 percent and 6 percent, as shown in Figure 18.

Looking more closely at the Unit's hourly and monthly generation, it appears that it has been operated mostly as a peaking facility. Because of this relatively low generation and Unit 4's relatively high fuel costs, it has not produced a healthy energy margin in recent years. For example, even if Unit 4 had generated power for sale only in the peak hours in each month of 2011, its energy revenues would have totaled only about $11.3 million for the entire year. This would have been less than the Unit's estimated fuel costs for the year that, according to SNL Financial, were nearly $12.9 million. Consequently, the Unit had a negative energy margin for the year.

Given the future energy market prices we have discussed, above, the prospects for flat energy consumption in ISO-NE, as a whole, and Massachusetts, in particular, and the low possibility that Unit 4's fuel costs will decrease significantly at any time in the foreseeable future, the plant is likely to continue to run negative energy margins in the future. Its primary benefit, therefore, for its owner would be as the source of capacity revenues. Unit 4 also is a potential target for a repowering to a new combined cycle natural-gas fired facility except that such a repowering would be more likely to create additional downward pressure on the energy revenues from Brayton Point Units 1-3.

Figure 17: Brayton Point Unit 4 Annual Capacity Factors 2006-2012



ENDNOTES

[1] For example, in 2012, the Massachusetts legislature established a task force to "identify and develop a plan for [] coal-fired generation facilities in the commonwealth that may face closure prior to December 31, 2017 that ensures the deconstruction, remediation and redevelopment or repowering of such sites." St. 2012, c. 209, An Act Relative to Competitively Priced Electricity in the Commonwealth, § 42.

[2] ISO-NE Release 2012 Wholesale Electricity Prices in New England Feel to Lowest Level Since 2003, dated January 23, 2013.

[3] Figure 9 only includes the first six months of 2012 because Dominion Resource's Quarterly Earnings Reports stopped presenting data on the New England Merchant Fleet EBITDA in the second quarter of 2012.

[4] Dominion's New England Merchant Fleet included the nuclear units at Millstone, the coal and the oil units at Brayton Point and Salem and the Manchester generating station.

[5] *New England: The Next Bust and Boom*, UBS Investment Research, November 6, 2012.

[6] Id.

[7] *Carbon Coming…but a Long Way Out*, UBS Investment Research, February 1, 2013.

[8] Id.

[9] The full Synapse 2012 CO2 price forecast is available at www.Synapse-Energy.com.

[10] Connecticut Department of Energy and Environmental Protection, Draft Comprehensive Energy Plan (Oct. 22, 2012)

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Economic Analysis of Schiller Station Coal Units

July 27, 2011

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Table of Contents

1. Executive Summary

As part of its 2010 Least Cost Integrated Resource Plan (LCIRP), Public Service of New Hampshire (PSNH) has proposed to continue operating two small, high-cost, coal-fired units (4 & 6) at its Schiller Station in Portsmouth, NH, during the LCIRP period.

Synapse's initial analysis of company filings—as well as public data from the Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), and ISO-New England (ISO-NE)—indicates that operation of the Schiller 4 and Schiller 6 coal units appears to be losing money for PSNH customers, as the generation costs are greater than the alternative costs of purchasing energy from the regional wholesale electricity market.

While wholesale energy prices are expected to increase at a modest rate in the future, no turn-around for these units seems likely. Additionally, any further capital expenses at Schiller for equipment replacement or environmental controls will only make the economic situation worse for PSNH customers.

In this report, Synapse evaluates a range of scenarios under which Schiller's coal-fired units would be required to meet likely and/or possible upcoming environmental regulations. These scenarios include the following:

- **Synapse's Reference Case.** This case assumes that the Environmental Protection Agency (EPA) will finalize its Maximum Achievable Control Technologies (MACT) rule in 2011, triggering a compliance deadline of 2015 for all sources subject to the rule. It further assumes natural gas prices consistent with the "Base Price Case" for natural gas projected in the *Avoided Energy Supply Costs in New England 2011 Report* (AESC 2011). This case assumes that compliance with the MACT rule would require the installation of a baghouse and activated carbon injection technology on each of Schiller's coal-fired units in 2015.
- **No New Environmental Costs**. This case assumes that no environmental controls will be required and that there is no national CO_2 regulation program. This case is consistent with PSNH's assertion that all potential environmental control costs are beyond their planning horizon, without suggesting any agreement of the authors with such assertion.
- **High Environmental Costs.** This case assumes a 2015 deadline for MACT compliance; the strengthening of the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (effective in 2017) and for ozone (effective in 2018); and a 2017 deadline for compliance with the proposed Cooling Water Intake Structure rule (under the Clean Water Act). This case assumes that Schiller 4 and 6's compliance with these rules would require the installation of a baghouse, activated carbon injection technology, and flue gas desulfurization technology in 2015; cooling towers in 2017; and selective catalytic reduction technology in 2018.
- **High Gas Prices:** This case assumes the same regulations and compliance technologies as the Reference Case; however, it assumes natural gas prices consistent with the "High Price Case" for natural gas projected in AESC 2011.
- **Low Gas Prices:** This case also assumes the same regulations and compliance technologies as the Reference Case; however, it assumes natural gas prices consistent with the "Low Price Case" for natural gas projected in AESC 2011.

- **Newington Market Prices:** This case is the same as the Reference Case but uses the capacity and energy prices from the revised Newington CUO analysis of the LCIRP. These prices are higher than current market conditions indicate but are included here for illustrative purposes.

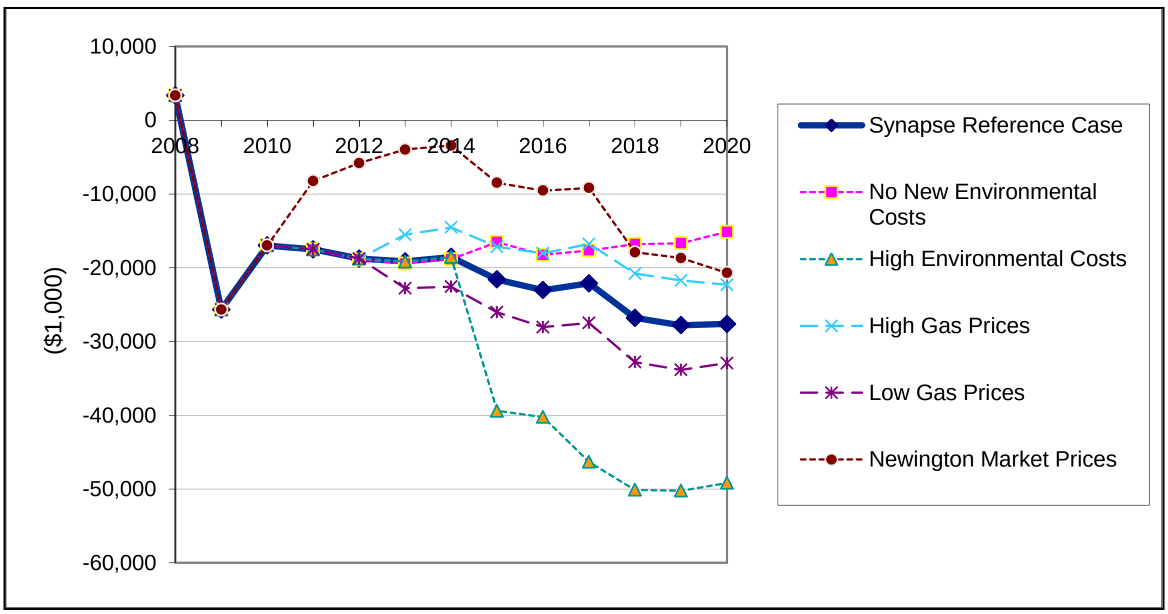
A summary of the regulations and compliance technologies assumed for each scenario is provided in Exhibit 1.

Exhibit 1: Regulations and Compliance Technologies for Study Cases

Case	Regulations	Schiller 4 Compliance Technologies	Schiller 6 Compliance Technologies
No Environmental Costs Case and Newington Market Prices Case	None	None	None
Reference Case, High Gas Prices Case, and Low Gas Prices Case	MACT (2015)	Baghouse (2015), ACI (2015)	Baghouse (2015), ACI (2015)
High Environmental Costs Case	MACT (2015), Ozone NAAQS (2018), SO2 NAAQS (2017)	Baghouse (2015), ACI (2015), FGD (2015), SCR (2018)	Baghouse (2015), ACI (2015), FGD (2015), SCR (2018)
	Cooling water intake structures (2017)	Cooling tower (2017)	Cooling tower (2017)

The impact that each of these scenarios would have on the net revenue of Schiller units 4 and 6 is shown in Exhibit 2. Under all of these scenarios, including the No New Environmental Costs case and the Newington Market Prices case, these units are projected to continue losing money for PSNH customers in every year during the study period (2011 – 2020). Over the entire period of ten years, they lose hundreds of millions of dollars in all but one case.

Exhibit 2: Schiller 4 and 6 Net Revenue



Synapse's calculations are based on public sources and may not correspond precisely to PSNH internal accounts. However, we believe they that fairly capture the overall economic situation, and we welcome more precise numbers from the company.

In light of Schiller's poor economic situation, upcoming environmental regulations that will only worsen that situation, and the associated risks to PSNH customers, Synapse recommends serious consideration be given to decommissioning these units.

2. Schiller Station: Running Less & Costing More

PSNH's Schiller Station currently has three operating units (4, 5, and 6) that were installed between 1947 and 1957.[1] Each unit is nominally rated at 50 megawatts (50 MW). Unit 5 has been converted to burn wood fuel, while units 4 and 6 continue to burn coal, along with modest amounts of #6 oil and natural gas primarily for startup. Our analysis focuses on units 4 and 6, which burn coal. Unit 5, which burns wood, appears to be marginally economic given renewable energy credits, but we have not analyzed that unit in detail.

Exhibits 3 and 4 (below) provide performance data for units 4 and 6 for the years 2008, 2009, and 2010. Points of interest include the following:

- Schiller units 4 and 6 were run far less frequently in 2009 and 2010 as compared to 2008, as shown by capacity factors of 83% in 2008, 58% in 2009, and 52% in 2010.
- While these units are producing less electricity for PSNH customers, they are costing more for every MWh they do produce. The production cost has risen from $69.2/MWh in 2008 to $90.5/MWh in 2009 and $87.6/MWh in 2010.
- Units 4 and 6 lost money for PSNH customers in 2009 and 2010 ($25.3 and $16.6 million respectively). As market prices for electricity have dropped (following the drop in natural gas prices), the generation costs for Schiller units 4 and 6 have been higher than the alternative costs of purchasing market energy. This trend is likely to continue given the long-term projection of low natural gas prices.

This is not surprising given the very high heat rates at the Schiller units. Unit 4 had a heat rate in 2009 of 13,019 BTU/kWh and Unit 6 was only marginally better at 12,644 BTU/kWh.[2] Units burning coal with such high heat rates would not be expected to run very often at all, if they were actually being dispatched in economic merit / order. The only surprise is that they still have capacity factors as high as they did in 2009 and 2010.

Exhibits 3 and 4 show the costs and revenues for these two units for the time period 2008 – 2010. As expected from the heat rates, these units were not economic in the past two years, losing more than $40 million in a very short period of time. As can be seen in our analysis, we expect this trend to continue.

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[1] As per the FERC Form 1 schedule 402 filing for 2010. The PSNH website says between 1952 and 1957.
[2] Source: Docket DE 10-121. Exhibit MDC-2, page 46.

Exhibit 3: Schiller Units 4 & 6 Historic Operations and Production Costs. (All values in $1,000 nominal) [3]

Expense Category	2008	2009	2010
Capacity Factor	83%	58%	52%
Fuel Cost ('000)	32,222	28,229	24,836
Heat Input (MMBtu)	8,430	6,225	5,617
Cost ($/MMBtu)	3.82	4.53	4.42
Generation (GWh)	693	481	434
Fuel Cost ($/MWh)	54.3	67.5	57.2
Production Expenses: Oper, Supv, & Engr	836	800	784
Fuel	32,222	28,229	24,836
Steam etc.	3,478	2,838	2,854
Allowances	2,760	3,560	3,171
Maintenance	8,698	8,126	6,384
Total Production Expenses	47,994	43,553	38,028
Production cost ($/MWh)	**69.2**	**90.5**	**87.6**

Exhibit 4: Historic Revenue Calculations. (All values in $1,000 nominal) [4]

Revenue Category	2008	2009	2010
Total Production Expenses	**47,994**	**43,553**	**38,028**
Depreciation	2,078	2,078	2,078
Rate Base Value	50,358	47,296	44,382
Rate Base Return	5,439	5,193	4,718
Revenue Requirements	**55,511**	**50,824**	**44,824**
Capacity Revenue	3,802	4,449	4,604
Generation Weighted Energy Price ($/MWh)	80.0	43.9	54.4
Energy Revenues	55,473	21,122	23,642
Total Revenues	**59,275**	**25,572**	**28,247**
Net Revenue	**3,764**	**-25,252**	**-16,577**

[3] Derived from FERC Form 1 Schedule 402 data.
[4] Calculated from discovery materials, ISO market data, EPA hourly CAMD generation data.

The analysis presented in Exhibits 3 and 4 above is based upon the following:

The generation and expense numbers are taken from FERC Form 1 Schedule 402 for Schiller Station. Fuel costs are allocated to the units based on fuel type (i.e., wood costs are assigned to the wood burning unit 5, and other fuel costs are allocated to units 4 & 6). Generation is assigned to the units based on fuel consumption and reported heat rates. Operating and maintenance costs are assigned to the units based on their fraction of the station's generation. Allowance costs are assigned to the coal units, although some small portion may be associated with the wood burning unit.

Depreciation and rate base costs are based on discovery materials and use of the historic rate of return from Exhibit G.1 in the LCIRP. Capacity revenue is based on ISO-NE capacity prices. Energy revenue is based on matching the hourly generation from the EPA CAMD data and the hourly day-ahead market prices from ISO-NE. No information was available on possible ancillary revenues for these units.

3. Likely and Possible Environmental Regulations Affecting Schiller 4 and 6

As bad as the economic analysis looks in the recent past, the future looks even worse if we consider the upcoming costs of complying with environmental regulations. Because they are older coal-fired units (50+ years old) with very high heat rates, Schiller 4 and 6 produce significant emissions as compared to supply- and demand-side alternatives, including natural gas plants, renewable energy resources, and energy efficiency measures. To the extent that these units are required to meet current and future Environmental Protection Agency (EPA) regulations, costs will continue to rise.

The Clean Air Act Toxics Rule (Utility MACT)

Synapse's Reference Case assumes that the EPA will finalize its MACT rule in 2011, triggering a compliance deadline of 2015 for all sources subject to the rule. This scenario appears to be very likely to occur, in light of the following developments.

In 2000, after a lengthy study, EPA found it was necessary to regulate toxic air emissions (or hazardous air pollutants, "HAPs") from utility steam electric generating units. As a result of that finding, EPA must adopt emission limitations for hazardous air pollutants that are based on the emissions of the cleanest existing sources.[5] These emission limitations are known as Maximum Achievable Control Technology (MACT). Although EPA was required to adopt MACT standards within two years after issuing its finding in 2000, the rules have been tied up in litigation.

On March 16, 2011, EPA proposed MACT emission limits for electric generating units. The final utility MACT rule, expected in late 2011, will establish emission limits for various toxic pollutants including mercury, acid gases, and non-mercury metals. As required under the Clean Air Act, the EPA's emissions limitations for existing units will be based on emissions achieved at the lowest

[5] Clean Air Act §112(d)

emitting 12% of electric generating units in the nation. The best-controlled units in the country use wet scrubbers (i.e., wet FGD systems), selective catalytic reduction (SCR) systems, and baghouses to control HAPs. In addition, activated carbon injection (ACI) may be required to control mercury.

In the proposed rule, EPA describes controls that will comply with a MACT rule, finding that combinations of existing control technologies, such as FGD scrubbers and SCR are useful in conjunction with baghouses and ACI for reducing mercury emissions:

> EPA projects that for acid, companies will likely use dry scrubbing and sorbent injection technologies rather than wet scrubbing. For non-Hg metal HAP controls, EPA has assumed that companies with ESPs [electrostatic precipitators] will likely upgrade them to FFs [fabric filter baghouses]. As a number of units that in the MACT floor for non-Hg HAP metals only had ESPs installed, this is likely a conservative assumption. For Hg, EPA projects that companies will comply either through the collateral reductions created by other controls (e.g. scrubber/SCR combination) or ACI. [proposed rule, page 442]

NAAQS and the Cooling Water Intake Structure Rule

Additional environmental rules under consideration that could impact Schiller's economic situation, and which are included in the High Environmental Costs case, include the following.

The National Ambient Air Quality Standards (NAAQS)

EPA promulgates "National Ambient Air Quality Standards" (NAAQS) pursuant to the authority granted by Clean Air Act §109 (42 U.S.C. §7409). Primary NAAQS are set to protect public health and secondary NAAQS to protect public welfare. The NAAQS are supposed to be evaluated and revised if necessary to protect public health and welfare at five-year intervals. EPA is currently working to improve NAAQS for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), ozone, and fine particulate matter, known as $PM_{2.5}$.

When EPA sets new standards for these pollutants, states must review air quality data and designate areas as either in "attainment" or "nonattainment." In nonattainment areas, sources must automatically comply with emission reduction requirements known as "Reasonably Available Control Technology" (RACT), and "new sources" (which includes major modifications at existing sources), must comply with very strict emissions reductions consistent with "lowest achievable emissions reductions" (LAER).

States containing areas that are designated nonattainment for any of the pollutants discussed above must develop a State Implementation Plan (SIP), to bring the air quality into compliance with the applicable NAAQS. Should counties in New Hampshire violate the standards, the state would develop SIPS requiring emissions reductions. To the extent that coal-fired units contribute to non-attainment, they will likely require controls to reduce overall emissions to help bring areas into attainment.

In the High Environmental Costs case, we assume that NAAQS will be strengthened for sulfur dioxide (effective in 2017) and for ozone (effective in 2018), in accordance with the following developments:

- SO_2: EPA adopted a new one hour average NAAQS for SO2 in 2010.6 All areas must attain the standard by 2017.
- Ozone: The EPA has proposed a new standard, and a final rule is expected by July 29, 2011.7 Final area designations will be due by late 2013 with attainment required by 2018.

The Clean Water Act Cooling Water Intake Structure Rule

On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants.8 Section 316(b) requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Under this new rule, EPA set new standards reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

The rule provides that:

- Existing facilities that withdraw more than two million gallons per day (MGD) would be subject to an upper limit on fish mortality from impingement, and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 million gallons per day would be required to conduct an entrainment characterization study for submission to the Director to establish a "best technology available" for the specific site.

In the High Environmental Costs case, we assume a 2017 deadline for compliance with the proposed Cooling Water Intake Structures rule, in accordance with the following developments:

EPA will finalize the rule in July 2012, and the regulations will become effective within 60 days thereafter. EPA stipulates that "as proposed, facilities would have to comply with the impingement mortality requirements as soon as possible."[9] However, facilities would have five years, and up to eight years on appeal, to comply with the impingement mortality requirements; and up to eight years at the discretion of the Director to comply with the entrainment provisions.

Therefore, Synapse assumes an outer compliance deadline of 2017 for impingement, and 2020 for entrainment.

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[6] 75 Fed. Reg. 35520 (June 22, 2010)
[7] 75 Fed. Reg. 2938 (Jan. 19, 2010).
[8] 33 U.S.C. § 1326.
[9] EPA. March 28, 2011. NPDES—Proposed Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities. EPA. p. 262

4. Input Assumptions for Cash Flow Analysis

Synapse's analysis of Schiller 4 and 6's performance and costs is based on public data from EIA, FERC, and ISO-NE. Thus, while it may not reflect precise details of Schiller operations, we believe it gives an accurate overall picture of Schiller's economic situation.

The details of our Reference Case calculations are shown in Exhibit 5, below.

This exhibit has been structured for convenience into a format that parallels the Newington analysis presented in Exhibit G.1 of the IRP.

The historic data for 2008 through 2010 has been extracted from the FERC Form 1 data filed by the company with the exclusion of the values associated with the wood burning unit 5. Going forward, we generally project values from 2010 increasing with inflation. One major exception is for the energy price, which in 2011 is based on actual market prices and current futures, and from 2012 on is based on AESC 2011. We have also adjusted the future prices to reflect the fact that a greater percentage of the output of Schiller units 4 and 6 occurs during on-peak load periods than off-peak load periods.

Note that the use of the AESC price is a conservative assumption since it represents an avoided cost of what the energy price would be if there were no new energy efficiency programs. The implementation of such programs would actually lower loads and the actual market prices would be below those values. The same rule applies for capacity costs, which would also be lower as the result of load reductions associated with EE programs.

5. Results of Cash Flow Analysis

Considering all expenses and revenues, our analysis shows that Schiller 4 and 6 had net revenues of about $3.3 million in 2008 and losses of $25.7 and $17.0 million in 2009 and 2010 (line 30). The projected loss for 2011 is $17.5 million. These calculations include various fixed costs such as depreciation and return on the rate base.[10]

The Net Cash Flow line in Exhibit 5 shows the results if depreciation and return on rate base are excluded. Still, the units lose money in all years except 2008.

One notable fact is that the units appear to be losing money on their generation operations. For example, the Variable Expenses line includes just Fuel and Allowances expenses. When that is compared with the Energy Revenues, these units appear to be losing money in all years except 2008. The primary reason for this is that wholesale market energy prices have dropped precipitously since 2008, while the fuel and other generation costs for these units have not. As stated above, wholesale market energy prices—and thus energy market revenues for these units—are expected to rise only slightly over the next ten years. We have seen no indication from PSNH that operating costs for these units are expected to decrease.

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[10] The historic expense and net revenue values differ slightly from those in Exhibit 4 since we have added here a nominal property tax item at 0.5% of the plant value.

Exhibit 5: Reference Case Revenue Requirements Analysis for Schiller Units 4 & 6 (All values in $1,000 nominal). Notes are listed on the following page.

	Notes	Historic 2008	2009	2010	Future 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	NPV 2011-2015	NPV 2011-2020
Expenses																
Non-Fuel O&M	1	13,012	11,764	10,022	10,000	10,200	10,404	10,612	10,824	11,041	11,262	11,487	11,717	11,951	$41,877	$73,933
Additional Environmental O&M	2				0	0	0	0	285	285	285	285	285	285		
Allowances	2	2,760	3,560	3,171	3,217	3,169	3,180	3,204	3,230	3,257	3,284	12,461	14,743	17,111	$12,909	$39,761
Total Non-Fuel O&M	3	15,773	15,324	13,193	13,217	13,369	13,584	13,816	14,055	14,298	14,546	23,948	26,459	29,062	$54,786	$113,694
Fuel and Fuel Related Expenses	4	32,222	28,229	24,836	25,700	26,214	26,738	27,273	27,819	28,375	28,942	29,521	30,112	30,714	$107,623	$190,008
Property Tax	5	416	416	416	416	416	416	416	583	583	583	583	583	583	$1,793	$3,423
Depreciation Expense	6	2,078	2,078	2,078	2,078	2,078	2,078	2,078	3,751	3,751	3,751	3,751	3,751	3,751	$9,544	$20,037
Total Expenses	**7**	**50,488**	**46,046**	**40,522**	**41,411**	**42,076**	**42,815**	**43,582**	**46,207**	**47,006**	**47,822**	**57,803**	**60,904**	**64,110**	**$173,746**	**$327,162**
Plant Values																
Capital Additions - General	8	0	0	0	0	0	0	0	0	0	0	0	0	0		
Capital Additions - Environmental	8	0	0	0	0	0	0	0	33,462	0	0	0	0	0		
Gross Plant Value	9	83,107	83,107	83,107	83,107	83,107	83,107	83,107	116,569	116,569	116,569	116,569	116,569	116,569		
Accum. Depreciation	10	40,694	42,771	44,849	46,927	49,004	51,082	53,160	56,910	60,661	64,412	68,163	71,914	75,664		
Net Plant Value	11	42,413	40,336	38,258	36,180	34,103	32,025	29,947	59,659	55,908	52,157	48,406	44,655	40,905		
Working Capital	12															
Year End Fuel Inventory	13	*7,945*	*6,960*	*6,124*	6,337	6,464	6,593	6,725	6,859	6,997	7,136	7,279	7,425	7,573		
Emissions Inventory	14															
Accum. Deferred Income Tax	15															
M&S Inventory	16															
Total Rate Base	17	50,358	47,296	44,382	42,517	40,566	38,618	36,672	66,518	62,904	59,293	55,685	52,080	48,478		
Average Return on Rate Base	18	10.80%	10.98%	10.63%	11.09%	11.09%	11.09%	11.09%	11.09%	11.09%	11.09%	11.09%	11.09%	11.09%		
Return on Rate Base	19	5,439	5,193	4,718	4,715	4,499	4,283	4,067	7,377	6,976	6,576	6,176	5,776	5,376	$19,854	$37,296
Revenue Requirements	**20**	**55,926**	**51,239**	**45,239**	**46,126**	**46,575**	**47,098**	**47,649**	**53,584**	**53,982**	**54,398**	**63,978**	**66,680**	**69,486**	**$193,600**	**$364,458**
Revenues																
Generation (GWh)	21	693.4	481.1	434.3	450.0	450.0	450.0	450.0	450.0	450.0	450.0	450.0	450.0	450.0		
Average Price ($/MWh)	22	80.01	43.90	54.44	54.4	54.4	54.5	57.0	63.2	65.5	66.8	75.6	78.4	81.5		
Energy Revenue	23	55,473	21,122	23,641	24,471	24,471	24,545	25,633	28,454	29,465	30,052	34,015	35,270	36,692	$102,432	$194,226
Capacity (MW)	24	96.01	96.01	96.01	96.01	96.01	96.01	96.01	96.01	96.01	96.01	96.01	96.01	96.01		
Capacity Price	25	39.6	46.3	48.0	43.2	34.8	35.5	36.2	36.8	15.4	23.2	33.0	37.8	53.9		
Capacity Revenue	26	3,802	4,449	4,604	4,148	3,337	3,404	3,472	3,538	1,482	2,223	3,167	3,624	5,172	$14,513	$22,923
Ancillary	27	0	0	0	0	0	0	0	0	0	0	0	0	0		
Total Revenue	**28**	**59,275**	**25,572**	**28,245**	**28,619**	**27,808**	**27,949**	**29,105**	**31,991**	**30,947**	**32,275**	**37,182**	**38,894**	**41,865**	**$116,945**	**$217,149**
Net Revenue	**29**	**3,349**	**-25,668**	**-16,995**	**-17,507**	**-18,766**	**-19,149**	**-18,544**	**-21,592**	**-23,036**	**-22,123**	**-26,796**	**-27,786**	**-27,621**	**($76,655)**	**($147,309)**
Net Cash Flow	30	8,787	-20,475	-12,277	-12,792	-14,268	-14,866	-14,477	-14,215	-16,060	-15,547	-20,620	-22,010	-22,245	($56,801)	($110,013)
Generation Operations																
Variable Expenses	31	34,982	31,789	28,007	28,917	29,383	29,918	30,477	31,049	31,632	32,227	41,982	44,854	47,825	$120,533	$229,769
Energy Revenue	32	55,473	21,122	23,641	24,471	24,471	24,545	25,633	28,454	29,465	30,052	34,015	35,270	36,692	$102,432	$194,226
Net Margin	33	20,491	-10,667	-4,366	-4,446	-4,912	-5,373	-4,844	-2,595	-2,167	-2,175	-7,967	-9,584	-11,133	($18,101)	($35,542)

Notes for Exhibit 5: Reference Case Revenue Requirements Analysis for Schiller Units 4 & 6

1	Historic values from FERC Form 1 and then increased at inflation in the future
2	Historic values from FERC Form 1 and then based on AESC emission prices and emission rates from CAMD.
3	Sum of 1 & 2
4	Based on 2010 value from Form 1 adjusted for assumed generation (21) and then increased at inflation.
5	Nominal 0.5% of gross plant value. Roughly consistent with Newington analysis.
6	2010 value from data request. Constant except for effects of capital additions.
7	Sum of above expenses
8	Mid case environmental controls. Twenty year depreciation life for item 6 above.
9	2010 value from data request. Will increase with capital additions.
10	2010 value from data request CLF-021. Increases with future capital additions.
11	Net value is Gross less accumulated Depreciation.
12	Unknown, zero used.
13	Estimated at 90 days of annual fuel expenses.
14	Unknown, zero used.
15	Unknown, zero used.
16	Unknown, zero used.
17	Total rate base is sum of above values.
18	Average return rate from Newington analysis. IRP, Exhibit G.7
19	Return rate times rate base
20	Sum of Total Expenses plus Return on Rate Base
21	From FERC data. Extrapolated at 2009 & 2010 values into future.
22	Historic energy prices from FERC Form 1. Future energy prices based on 2010 relationship of hourly generation and price data applied to AESC 2011 peak and off-peak price forecast.
23	Energy revenue is generation times market price.
24	Annual capacity from CELT
25	Capacity price from AESC 2011
26	Capacity revenue is product of above
27	Ancillary revenues are unknown but likely small.
28	Total revenue is sum of above revenues.
29	Net revenue is based on total requirements including return on rate base.
30	Net Cash Flow excludes return on rate base expense.
31	Fuel + Allowances
32	Energy Revenue
33	Net Margin (32 - 31)

For summary purposes, we have also calculated the net present value (i.e., the difference between the present value of cash inflows and the present value of cash outflows) of various cost and revenue streams over the period from 2011 – 2020, as was done for the Newington analysis. Our Reference Case shows revenue requirements of $364 million and revenues of $217 million for a negative net revenue value of $147 million. This is shown above in Exhibit 5 and summarized in Exhibit 6 below.

While our Reference Case, which is based on public data and the recently completed AESC study, is the most likely situation, we have also evaluated a number of alternatives cases, which are outlined in the Executive Summary.

As mentioned earlier, the Newington Market Prices case uses the capacity and energy prices from the Newington CUO analysis in Appendix G of the LCIRP. On a NPV basis that increases revenues by almost $50 million. However, the prices used in that analysis are higher than current ISO-NE capacity and energy prices, and also above the current futures. Thus they do not appear to be representative. For this case, we also use emission costs that assume no significant future CO_2 price increase. Even with all these changes, the Schiller coal-fired units have a negative net present value (NPV) revenue worth of $66 million for the 10-year period 2011 – 2020.

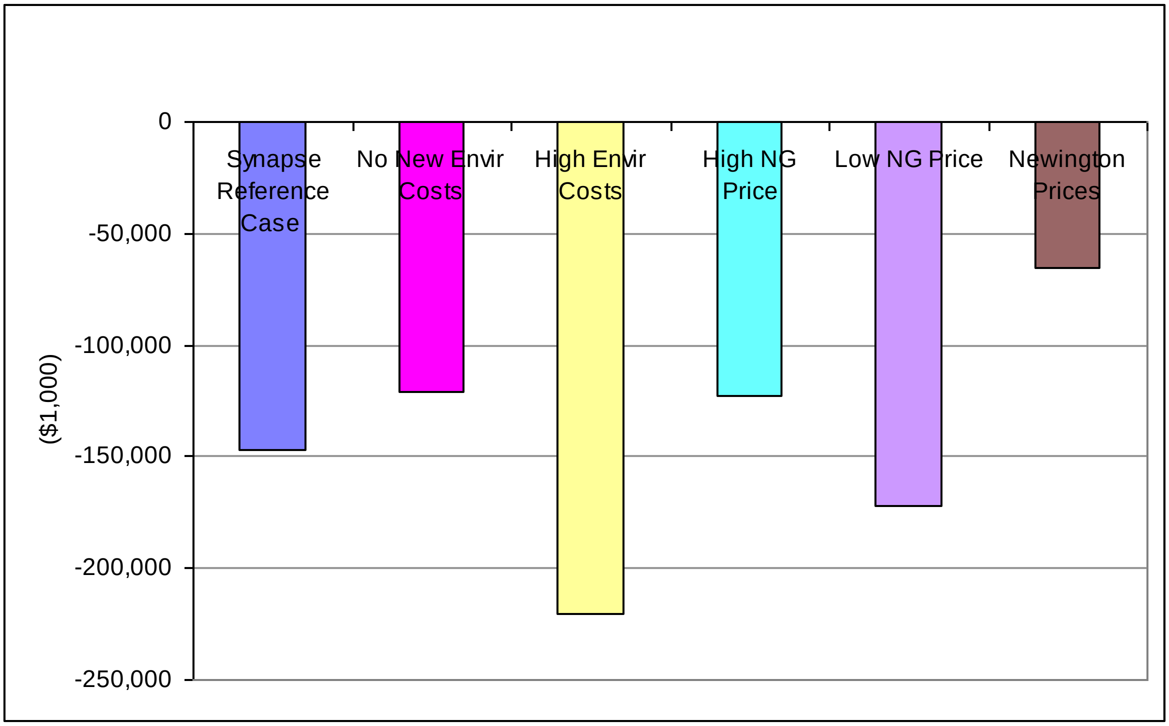
We also looked at two cases with higher and lower natural gas prices based on the AESC study (the Low Gas Prices and High Gas Prices cases). Gas prices primarily affect the wholesale energy price and thus the energy revenues. As shown in Exhibits 6 and 7 below, none of these significantly change the negative net revenue situation for the Schiller coal units.

Exhibit 6: Alternative Case Comparisons - NPV Analysis 2011 – 2020 (All values in thousand 2011 dollars.)

Category & Case	Synapse Reference Case	No New Envir Costs	High Envir Costs	High NG Price	Low NG Price	Newington Prices
Total Expenses	$327,162	$304,764	$354,124	$327,162	$327,162	$327,162
Return on Rate Base	$37,296	$26,470	$83,223	$37,296	$37,296	$37,296
Total Revenue Requirements	**$364,458**	**$331,234**	**$437,347**	**$364,458**	**$364,458**	**$364,458**
Energy Revenues	$194,226	$187,071	$194,226	$218,677	$169,776	$272,278
Capacity Revenues	$22,923	$22,923	$22,923	$22,923	$22,923	$26,673
Other Revenues	$0	$0	$0	$0	$0	$0
Total Revenues	**$217,149**	**$209,994**	**$217,149**	**$241,600**	**$192,699**	**$298,951**
Net Revenue	**($147,309)**	**($121,240)**	**($220,197)**	**($122,858)**	**($171,759)**	**($65,507)**

The net present value of Schiller units 4 and 6 under each case is presented in graphic form in Exhibit 7.

Exhibit 7: Schiller 4 and 6 NPV, 2011 – 2020 (All values in thousand 2011 dollars.)



6. Conclusions & Recommendations

Schiller units 4 and 6 have been losing money for the past two years, and will continue to lose money over the next ten years. This conclusion remains true even if one were to adopt the optimistic energy revenue assumptions used in the Newington CUO study, and still further even if these units were subject to no additional capital expenditures to meet upcoming environmental regulations. Ratepayers in PSNH territory should not be subject to these costs, and certainly not without proper planning by the Company. The New Hampshire Public Utilities Commission should require an independent Continued Unit Operations study on the Schiller station because these units are losing money each year, and will lose more when required to invest hundreds of millions of dollars to meet environmental regulations.

While the AESC 2011 and other studies project a modest increase in wholesale energy prices in the future, an increase large enough to turn around the economic shortcomings of units 4 and 6 seems unlikely—especially when the likelihood of stricter EPA regulations on coal-fired units is considered.

These calculations are based on public sources and may not correspond precisely to PSNH internal accounts. However, we believe that they fairly capture the overall economic situation, and we welcome more precise numbers from the Company.

Further analysis could focus on sensitivities in costs of emission controls for these units. But given their age, operating costs, low reliability, and high heat rates, there is not likely to be any economic future for these units.

7. About the Authors

Doug Hurley

Doug Hurley is an associate with Synapse Energy Economics, where he represents the interests of our consumer advocate, environmental, and renewable resource clients at numerous ISO-NE and PJM stakeholder meetings. He was the lead client representative for three members of the Alternative Resource (AR) sector in the LICAP Settlement Conferences which, with help from other parties, successfully included demand response and energy efficiency in the design of the new capacity market. Mr. Hurley is currently serving in his second year as the vice-chair of NEPOOL's AR Sector, and has now spent four years actively advising numerous clients participating in the Forward Capacity Market with energy efficiency and distributed generation resources.

Prior to joining Synapse, Mr. Hurley was the head of the West Coast research arm of a website hosting company, and spent seven years as a technology consultant for Ernst & Young. Mr. Hurley graduated with a B.S. in Electrical Engineering from Cornell University.

David White

David White is a senior consultant with Synapse Energy Economics. The primary focus of his work is the technical analysis and modeling of electricity system operations and expansion, electricity industry regulation, energy efficiency programs, renewable resource technologies, and clean air regulations and policies. Dr. White has modeled most of the North American Electric Reliability Council (NERC) regions in the United States and Canada. Many of these projects have involved examining proposed mergers and their potential effects on market power and market prices. A recent focus has been on the analysis of long-term generation expansion plans and the role of uncertainty in those analyses.

Dr. White's recent work includes consulting on electric industry restructuring, stranded costs, system benefits, market power, mergers and acquisitions, generation asset valuation and divestiture, power plant costs and performance, renewable resources, power supply contracts and performance standards, green marketing of electricity, environmental disclosure, climate change policy, environmental externalities valuation, energy conservation and demand-side management, electric power system reliability, and electricity market simulation modeling for price forecasting and market power analysis.

He holds a PhD in engineering systems from the Massachusetts Institute of Technology and BS and MS degrees in physics. He has analyzed energy systems and been involved with computer modeling since the mid 1970s, including five years at the MIT Energy Laboratory. Dr. White worked with Energy Systems Research Group (later Tellus Institute) where he had a lead in developing many computer modeling systems for energy and environmental analysis.