The Economics of Closed Cycle Cooling in New York

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Executive Summary

Detailed analysis of closed cycle cooling for all power plants in New York State makes four significant findings. Most important, it identifies two old, inefficient power plants that could be closed without affecting the level of reserve capacity (see page 17).

1. Environmental compliance at the Oswego Steam Station implies plant closure or repowering. This is an uncompetitive oil plant that only generated power 0.06% of the time in 2008. The effect of its closure on price and reliability would be inconsequential.
2. Assuming the passage of aggressive carbon surcharge legislation as well as closed cycle cooling, the C.R. Huntley Generating Station near Tonawanda is a candidate for closure or repowering. Replacement by a combined-cycle natural gas plant would ensure significant air quality benefits (see page 21).
3. The change in electricity prices as a result of requiring closed cycle cooling would be less than 1 percent.
4. An opportunity exists to reduce the cost of power by reforming the current wholesale electricity market mechanism which results in high prices for New Yorkers.

The analysis shows that these two plants seldom set the price of electricity in New York (see page 20). The prices received by the plants in this study are more than enough to pay the costs of environmental compliance. Allowing these plants to operate with sub-standard cooling systems while imposing massive burdens on public water bodies and ecosystems is both unfair to New Yorkers and to the power producers owning modern plants that efficiently use fuel and water.

Given these findings, the power industry in New York could easily bear the additional cost of closed-cycle cooling. In addition, a requirement for closed cycle cooling would cost power customers very little, would have no adverse impacts on reliability, and would improve air quality.

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The Eastern Environmental Law Center asked us to review the cooling water intake structures policy issued on March 4, 2010 with special emphasis on the economic analysis contained in Table 6 in Appendix A of the draft BTA policy of the New York State Department of Environmental Conservation.[1]

Table 6 contains a preliminary analysis of the economic impacts of bringing the cooling systems of 27 New York facilities into environmental compliance. However, the analysis while useful is neither detailed nor complete. The concept behind the table is to compare revenues from the New York Independent System Operator's energy market with the capital and O&M costs associated with environmental compliance. On the far right of the table is a "Cost-Revenue Ratio" reflecting a rule of thumb appreciation of the economic impact.

Table 6: Estimated compliance costs for the steam electric industry in New York State.

Facility Name	Capital Costs	Operation & Maintenance Costs (20 years)	Total Costs	20-year Revenue	Cost - Revenue Ratio
Indian Point	$1,079,451,875	$345,424,600	$1,424,876,475	$24,168,528,480	5.9
Astoria Generating	$540,431,250	$172,938,000	$713,369,250	$6,232,600,000	11.4
Oswego Steam Station	$539,120,833	$172,518,667	$711,639,500	$523,857,252	135.8
Ravenswood	$536,076,042	$171,544,333	$707,620,375	$7,796,876,244	9.1
Northport	$361,728,958	$115,753,267	$477,482,225	$15,362,526,680	3.1
Roseton	$356,807,188	$114,178,300	$470,985,488	$3,183,683,722	14.8
Bowline 1&2	$351,553,958	$112,497,267	$464,051,225	$1,414,251,573	32.8
Huntley	$325,904,479	$104,289,433	$430,193,913	$2,409,262,820	17.9
Arthur Kill	$274,956,250	$87,986,000	$362,942,250	$1,855,000,000	19.6
Fitzpatrick	$240,153,125	$76,849,000	$317,002,125	$8,038,232,251	3.9
Poletti	$239,617,396	$76,677,567	$316,294,963	$3,582,202,485	8.8
Dunkirk	$222,971,250	$71,350,800	$294,322,050	$3,573,800,000	8.2
Ginna	$188,923,542	$60,455,533	$249,379,075	$4,612,289,070	5.4
Nine Mile Point	$188,723,125	$60,391,400	$249,114,525	$16,490,083,300	1.5
Danskammer	$176,324,271	$56,423,767	$232,748,038	$3,490,140,317	6.7
Port Jefferson	$153,704,167	$49,185,333	$202,889,500	$3,162,734,117	6.4
EF Barrett	$113,447,396	$36,303,167	$149,750,563	$2,865,381,700	5.2
AES Somerset	$107,346,250	$34,350,800	$141,697,050	$5,792,311,378	2.4
AES Cayuga (Milliken)	$84,406,250	$27,010,000	$111,416,250	$2,697,921,458	4.1
Glenwood	$66,939,167	$21,420,533	$88,359,700	$952,476,512	9.3
Russell	$48,285,000	$15,451,200	$63,736,200	$1,433,606,013	4.4
AES Greenidge	$43,552,083	$13,936,667	$57,488,750	$1,048,558,645	5.5
AES Westover(Goudey)	$39,258,542	$12,562,733	$51,821,275	$879,510,146	5.9
Far Rockaway	$32,182,292	$10,298,333	$42,480,625	$559,636,320	7.6
East River	$122,177,083	$39,096,667	$161,273,750	$1,126,860,000	14.3
Black River Power	$21,197,917	$6,783,333	$27,981,250	$497,623,667	5.6
Brooklyn Navy Yard	$21,197,917	$6,783,333	$27,981,250	$2,935,918,696	1.0
Total Compliance Costs:	**$6,476,437,604**	**$2,072,460,033**	**$8,548,897,638**	**$126,685,872,845**	**6.7**

[1] CP-nn / Best Technology Available (BTA) for Cooling Water Intake Structures, New York State Department of Environmental Conservation, March 4, 2010, page 14.

While the table does give an overall sense of the relative impacts, its problems can be briefly itemized:

1. The revenues used are both incomplete and anachronistic. While zonal energy costs are an important component of revenues in the New York ISO, other revenues[2] – most significantly uplift payments – also play a significant role in certain areas of the state. New York ISO prices are extremely volatile, so the use of 2007 prices with average generation for a period across five years will give incorrect results.[3]
2. Multiplying 2007 prices by twenty years is very likely to give a biased forecast of actual revenues. This is especially true given the enormous increase in New York ISO prices in 2008 as well as long-term forecasts available from the U.S. Energy Information Administration.
3. The impact on a specific facility cannot be estimated by considering only its revenues. A plant with high revenues may well be the least profitable plant if its fuel and O&M costs approximate its revenues. As discussed below, a correct analysis compares the net income against the expected cost of environmental compliance.

While incomplete, Table 6 largely matches the results of the detailed analysis undertaken in this report.

Can the Required Environmental Compliance Measures Be Prudently Undertaken?

1. What is the impact on the plant owner of environmental compliance?
2. What is the impact on society of environmental compliance?

The first question is relatively straightforward. Almost every car owner faces this question at some point. The value of a car must be compared against the incremental cost of repairs. The owner of an older car must compare the cost of a new transmission against an estimate of the continued usefulness of the vehicle. A relatively new vehicle will receive repairs. An older, less viable one will be sold to the junkyard.

Metaphorically speaking, this is the same economic decision to be made by a plant owner facing a major environmental upgrade. Will the future expected net income – revenues minus operating costs – of the plant be greater than the predicted cost of environmental compliance? If they are, the plant owner will

[2]Other revenues are composed of ancillary services, immediately responsive generating capacity (spinning reserve), capacity needed to serve load in the event of a contingency (supplemental reserve), and make-whole payments by an RTO/ISO to a utility (uplift). See, for example, http://www.ferc.gov/docs-filing/eqr/soft-tools/eqrdatadictionary.pdf

[3]Ibid., page 20.

decide to continue operating. If they are not, the plant owner will decline to make the required investment and instead retire the facility. While this decision may prove stressful for shareholders in the short term, it is one of the business issues addressed regularly by management found in SEC 10Ks and other financial filings. The lifetime of electric generation facilities is usually limited to 35 to 50 years and closure is usually related to an economic change that does not meet this simple test.

Analyzing this decision would be difficult without the ready source of data on future fuel costs, O&M, and electric prices in New York issued annually by the U.S. Energy Information Administration. The most recent forecast is the Annual Energy Outlook 2010 (AEO 2010), which analyzes electric operations separately for New York State.[4]

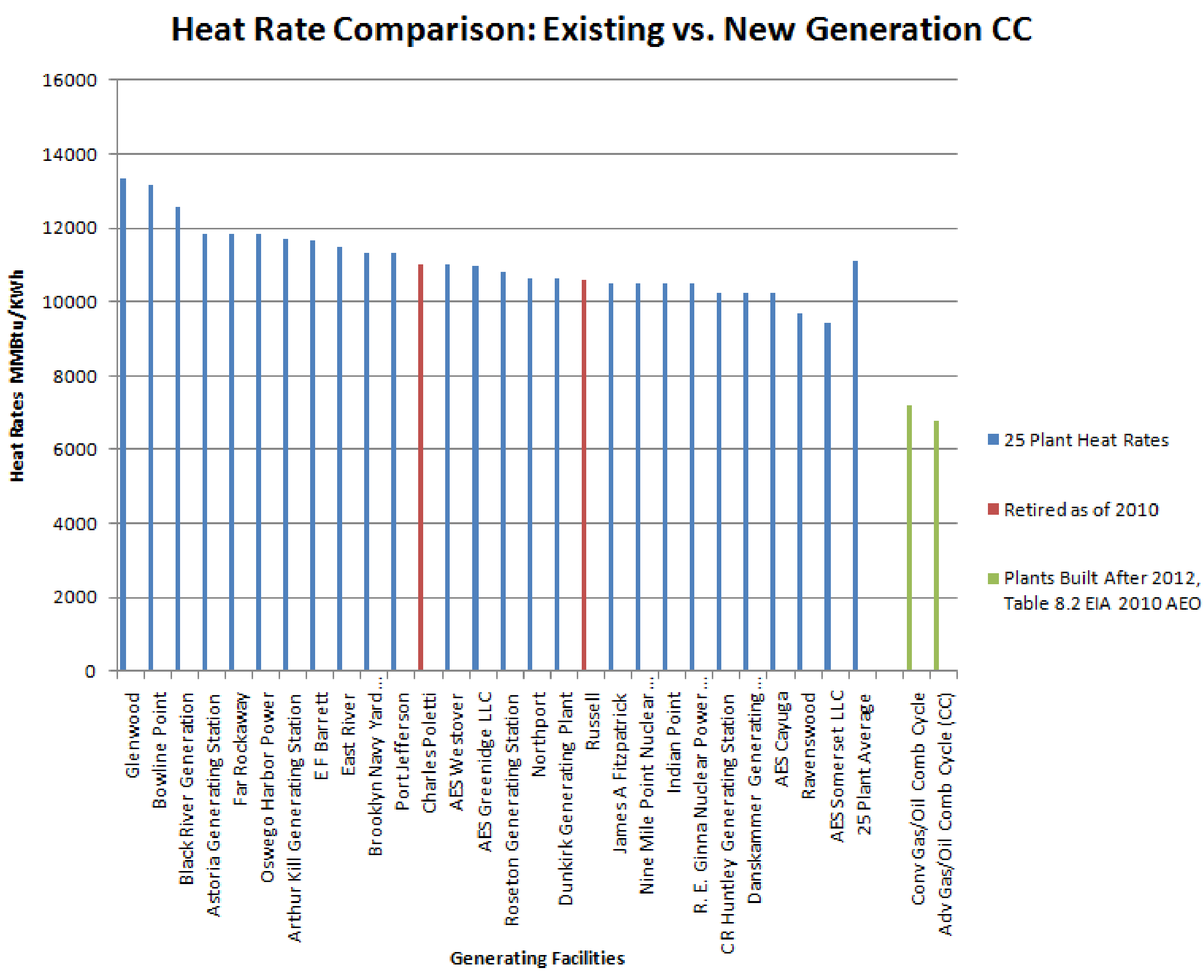
Given the data available on each of the 25 plants (two of the 27 plants are no longer in operation and do not require analysis), it is relatively easy to model plant operations, revenues, and incremental costs over the next 25 years.[5] The expected net revenues are then brought to current dollars using the real tax-adjusted weighted cost of capital for each facility.[6] If discounted net revenue is greater than the cost of environmental compliance, the plant will continue operating. If not, the rational profit-seeking company will close the plant, repower it, or replace it with a more efficient plant that uses either dry cooling or wet closed-cycle cooling.

The second question is more complex. Electric rates in New York reflect bulk market costs and local distribution costs. The latter will be unaffected by environmental compliance. Bulk market costs may well be affected if a number of the plants are closed if forced to meet environmental standards. The impact on prices is twofold. First, closure of a number of plants may affect the load/resource balance in New York. If so, new plants would need to be brought on line to meet the state's needs for capacity. Second, the elimination of plants or changes in the marginal costs of plants may affect the energy market in New York.

A priori, the impact on consumers may well be beneficial. Elimination of older, less efficient facilities via replacement with more efficient facilities can have the impact of reducing energy costs as well as plant emissions. The heat rates of the plants in the BTA Policy Technical Document have significantly larger

[4]Annual Energy Outlook 2010, Report #:DOE/EIA-0383(2010), May 11, 2010. A glossary of technical terms is in Appendix A to our report.
[5]For the five Long Island plants in the analysis, this prediction is difficult, because the Long Island Power Authority has a long-term power purchase agreement in place, but it expires in 2013. Because it is not possible to predict what any new contract might contain, our analysis assumes that the plants on Long Island become part of the larger New York ISO market.
[6]Black River Generation had no readily available financial filings. In this case we assume the average discount rate of the remaining 24 facilities.

incremental costs than newer units. Average heat rates for the plants in the BTA Policy Technical Document were much higher than that of a modern combined cycle unit, as the following graph shows.[7]



In this case, the analysis is straightforward since only the Oswego Steam Station is likely to face closure as a result of the BTA policy alone. The unit neither dramatically changes the load/resource balance in New York, nor provides significant energy to meet New York's energy requirements to impact the state's energy markets. Even when adding in a scenario for the future pricing of carbon, as prudent entrepreneurs have already started to do, only C.R. Huntley in addition to Oswego would go offline. Again, the loss of Huntley would not cause any major effect on price or reliability.

[7] Average heat rates for the plants in the BTA Policy Technical Document were much higher than a modern combined cycle unit. Heat rates from plants built after 2012 appear in AEO 2010 at http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf#page=3

Our report assumes throughout that the New York markets are efficient, meaning that bids and prices will reflect the producers' true marginal costs. This very conservative assumption is a "worst case" for the plants studied since it assumes that average wholesale prices in New York will reflect average marginal costs over time. In reality, prices in New York are often higher than marginal costs; hence our assumption would have the effect of overestimating the negative financial effects of environmental compliance.

Modeling Impacted Electric Facilities 2010 through 2035

On an annual basis, the U.S. Energy Information Administration undertakes a detailed 25-year forecast of energy for the United States. The most recent forecast, AEO 2010, was issued on May 11, 2010. The forecast contains detailed subforecasts by energy type and geographic area; we use the electricity module for the state of New York. The benefits of having a detailed forecast of New York include:

1. The forecast is impartial. The EIA has taken no position in the current proceeding.
2. AEO 2010 is the product of a modeling process undertaken for many years. The EIA's forecasts have been reviewed and tested in many arenas. They are relied upon to set U.S. policy by the U.S. government in many venues.
3. The AEO is well-documented with thousands of pages of detailed analysis standing behind the forecast.

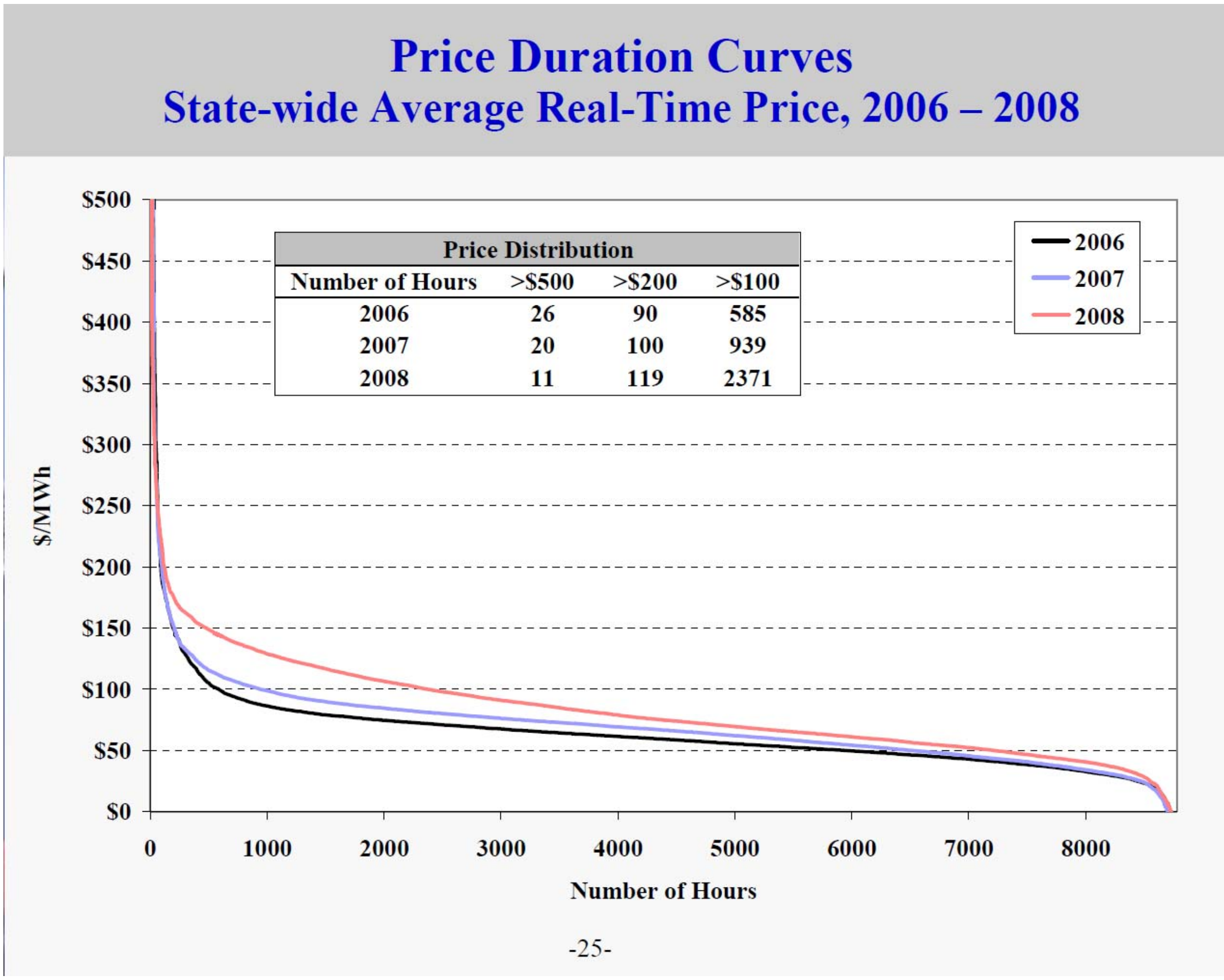
Since the volatility of New York ISO prices is high, we adjust the average levels forecasted by the EIA by the actual prices from 2008 in order to reflect generation opportunities for high-price units like the Oswego Steam Station. We also conduct a sensitivity case using EIA fuel forecasts to observe the potential impact of carbon tax or cap and trade policy changes.

The New York Independent System Operator Markets

For the past decade, the New York ISO has operated a highly stylized administrative system of prices. The basic structure resembles a market with bids, bidders, and a market settlement mechanism. Unlike a market in the more traditional sense, the bids, bidders, and the settlement mechanism are complex and secretive.

Overall, market results in New York are both higher and more volatile than would exist in an open market. For the purposes of this report we have assumed the distribution of electric prices by subregion from 2008 and escalated the curve using the most recent forecast of New York electric operations from the U.S. Energy Information Administration.

The following chart illustrates the distribution of prices in New York. Prices above $150/MWh would not normally occur without extensive system emergencies or significant market power. The EIA's forecast, for example, does not produce prices above $153.39/MWh over the period from 2008 through 2035. The New York ISO, however, experienced day ahead prices as high as $378.82/MWh in 2008.[8]



In analyzing the revenue prospects of eligible plants we set the mean of the actual 2008 price distribution to the forecasted value from the EIA. This approach provides a simulation of the higher volatility experienced in New York, while following the levels predicted in the detailed EIA forecasts for the next 25 years.

The New York ISO also administers capacity markets, markets for ancillary services, and specific reliability-related dispatch payments. The reliability-related dispatch payments are loosely based on plant bids. Payments in this case are described by the phrase "uplift".

[8] 2008 State of the Market Report, David Patton, page 25.

Ancillary service and uplift revenues for 2008 are taken from each plant owner's Electric Quarterly Reports to the Federal Energy Regulatory Commission. Capacity revenues are based on capacity prices forecasted in AEO 2010.[9]

The first step is to calculate the weighted, tax-adjusted real cost of capital. The initial step in the calculation of the cost of capital is to find the cost of equity. We use the Capital Asset Pricing Model to calculate this cost.

1. Beta

The beta coefficient (β) of an asset is a statistic that describes the correlation between its rate of return and that of the financial market as a whole. A positive beta indicates that the asset's returns generally follow the overall market's returns. It is found by dividing the covariance between the rates of return of the asset and the market by the variance of the rate of return of the market:

$$\beta_a = \frac{\mathrm{Cov}(r_a, r_p)}{\mathrm{Var}(r_p)},$$

where r_a is the rate of return from holding the asset and r_p is the rate of return in the market.

The most recent market beta is obtained for each plant owner from the Market Club.[10] It is then used to calculate the expected rate of return on equity:

$$y = t_R + t_p * \beta,$$

where y is the cost of equity, t_R is the risk-free rate of return, and t_p is the risk premium.

2. Tax-Adjusted Cost of Capital

Cost of capital is the cost of obtaining capital for long-term investment in plant and equipment. Companies create value for their shareholders by earning a return on their invested capital that exceeds the cost of obtaining that capital. The cost of obtaining the capital is usually expressed as a percentage of the amount of capital obtained. For example, in the case of debt, the cost of capital is the rate of interest paid on the debt. In the case of equity, it is the expected yield on the market value of outstanding common stock.

[9] AEO 2010, New York Prices by Time Slice.
[10] Market Club, Charting: Quotes and Fundamental Data, Members Section.

For each power plant, we estimate the cost of capital by calculating the average of the owner company's costs of debt and equity, weighted by the proportion each respective component of capital constitutes in the company's capital structure.[11] Cost of debt is the average annual rate at which the company pays out interest on its total outstanding long-term debt, i.e. the ratio of its total interest expenditures in a given year to its total outstanding long-term debt in that year. Since interest expenditures are tax deductible, only the after-tax portion of the debt is taken into consideration when determining the cost of debt to the company.[12] Similarly, the cost of equity is the market yield on the outstanding shares of the company. In accordance with the standard Capital Asset Pricing Model (CAPM), we estimate it by adding to the prevailing risk-free rate of return in the economy a company-specific risk premium that is found by adjusting the market specific risk premium with the beta coefficient of the individual companion that market (see above).

This method of accounting for a company's overall cost of capital is known as its Weighted Average Cost of Capital (WACC):

$$\text{WACC} = \frac{(\text{Debt})(1 - \text{tax rate})}{(\text{Debt} + \text{Equity})}(\text{Cost of Debt}) + \frac{(\text{Equity})}{(\text{Debt} + \text{Equity})}(\text{Cost of Equity}),$$

$$\text{Cost of Debt} = \frac{\text{Interest Expense}}{\text{Outstanding Long–Term Debt}}$$

$$\text{Cost of Equity} = \text{Riskless Return} + \beta_{company} * (\text{Market Return} - \text{Riskless Return})$$

We take the expected rate of return in the market to be 9% and the prevailing risk-free rate of return to be 4.28%, which is the average of the 30-year U.S. Treasury bond yields in 2008.[13] The tax-adjusted WACCs range from 4.92% for East River Generating Station and Brooklyn Navy Yard Cogeneration to 8.35% for the AES plants, Cayuga, Greenidge, Somerset, and Westover.

Plants owned by companies with low betas have lower WACCs than plants owned by companies with high betas. For example, East River Generating Station, owned by Consolidated Edison Company of New York, has a relatively low beta (0.3) and a relatively low tax-adjusted WACC (4.92%). Conversely, AES

[11] Publicly traded companies provide their income statements and balance sheets in Form 10-Ks filed at the U.S. Securities and Exchange Commission. Black River Generation did not have readily available financial filings. In this case, we assume the average discount rate of the remaining 24 facilities.

[12] We assume a 35% federal income tax rate.

[13] Average U.S. Treasury yield rate for 2008 is at http://www.federalreserve.gov/releases/h15/data/Annual/H15_TCMNOM_Y30.txt

Cayuga, owned by AES Eastern Energy, has a relatively high beta (1.45) and a relatively high tax-adjusted WACC (8.35%).

3. Tax-Adjusted Real Discount Rate

The value of a company, an asset, or a project, is estimated by adding up the net present values of its future cash flows. It is standard practice to discount the cash flows using the weighted average cost of capital of the company. However, because we report our results in real terms (2008 dollars), we convert the plants' nominal WACCs to real WACCs with the assumption of a 3.5% average annual inflation rate over the horizon of interest to us.

$$\text{Real WACC} = \frac{1 + \text{Nominal WACC}}{1 + \text{Expected Inflation Rate}} - 1$$

The tax-adjusted real discount rates range from 1.37% for Brooklyn Navy Yard and East River to 4.69% for the AES plants.

The estimated future profits of the plants are then discounted at the real tax-adjusted discount rate to 2008 dollars and added up for comparison with the estimated costs of the closed-cycle cooling systems over the 25 years.

4. Fuel Costs

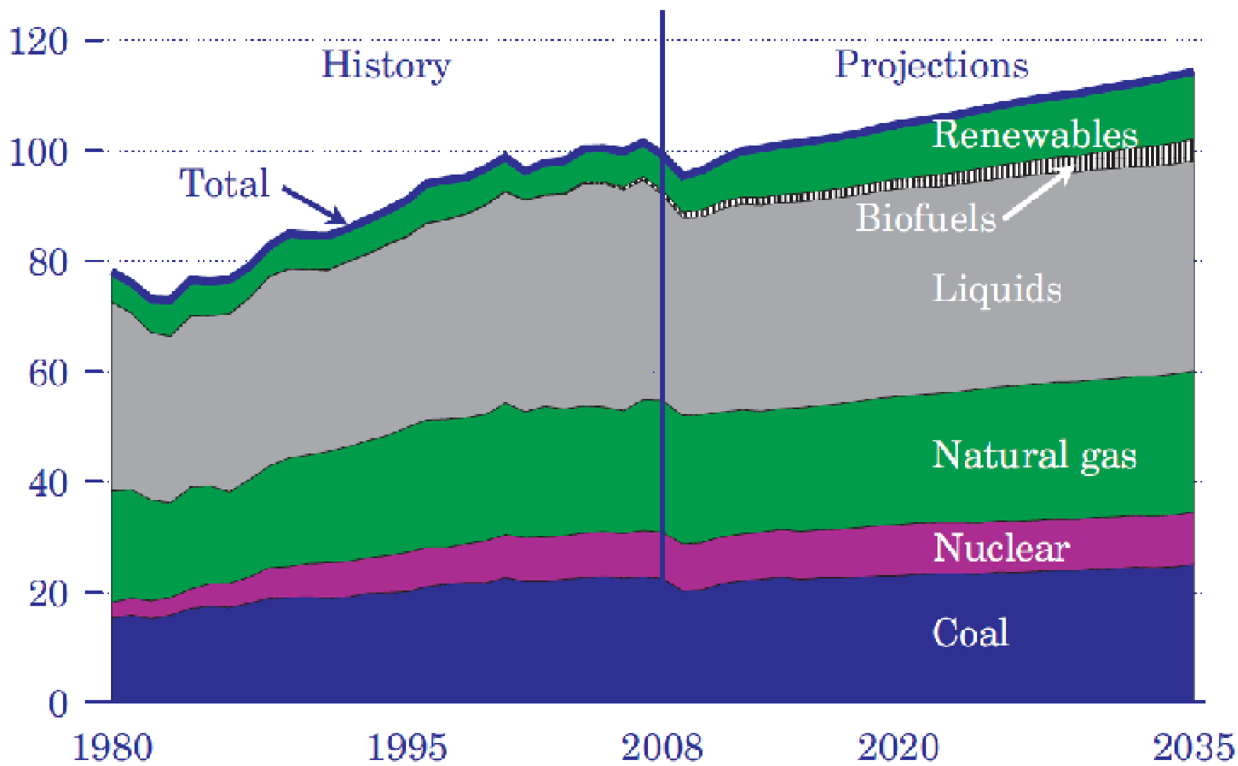
Estimated fuel prices are taken from the EIA which projects fuel prices up to 2035.[14] On the demand side, the AEO predicts moderate growth in energy consumption. Total primary energy consumption increases by 14% between 2008 and 2035, an average annual growth rate of 0.5%, which is well below the predicted 2.4% growth rate of national economic output.[15] This difference is the result of the U.S. economy decreasing in energy intensity, as well as increased efficiency of energy-consuming appliances, vehicles, and structures.

[14] AEO 2010, Electricity Generation & Renewable Resources, Table 77 Electric Power Projections for EMM Region Northeast Power Coordinating Council/ New York at http://www.eia.doe.gov/oiaf/aeo/supplement/index.htmlhttp://www.eia.doe.gov/oiaf/aeo/supplement/sup_elec.xls

[15] AEO 2010, Executive Summary at http://www.eia.doe.gov/oiaf/aeo/pdf/execsummary.pdf

On the supply side, there is a declining reliance on imported liquid fuels, but much of this slack is taken up by strong growth in generation from renewable sources. The increased production of shale gas is predicted to offset the decline in gas production from other sources, making natural gas a viable option for electricity production.

U.S. primary energy consumption, 1980-2035 (quadrillion Btu) [16]



AEO 2010 forecasts a steady increase in the price of every fuel except uranium. The price of petroleum increases most drastically between 2010-2035 with a 74% increase in the price of distillate fuel oil and a 104% increase in the price of residual fuel oil. Coal only sees a 22% price increase, but this assumes there will be no legislation restricting carbon emissions.

5. O&M Costs

Operations and maintenance costs for a power plant include labor, materials and supplies, contractor services, licensing fees, and miscellaneous costs, such as employee expenses and regulatory fees.[17] We

[16] Ibid.

estimate the O&M costs for each unit using the Nuclear Energy Institute's annual report, *US Electricity Costs and Components*, which gives the average cost of different electricity production components by fuel type.[18]

U.S. Electricity Production Costs and Components
1995 - 2009, In 2009 cents per kilowatt-hour

NUCLEAR ENERGY INSTITUTE

	Total Production Costs				Operations & Maintenance Costs				Fuel Costs			
Year	Coal	Gas	Nuclear	Petroleum	Coal	Gas	Nuclear	Petroleum	Coal	Gas	Nuclear	Petroleum
1995	2.56	3.73	2.69	5.83	0.61	0.71	1.89	1.64	1.96	3.02	0.80	4.20
1996	2.41	4.56	2.52	5.93	0.54	0.70	1.80	1.36	1.88	3.86	0.72	4.57
1997	2.33	4.62	2.64	5.33	0.52	0.67	1.93	1.16	1.81	3.95	0.71	4.17
1998	2.28	4.04	2.45	3.75	0.55	0.61	1.75	0.72	1.73	3.44	0.70	3.03
1999	2.20	4.37	2.21	4.50	0.52	0.51	1.57	1.02	1.67	3.86	0.64	3.47
2000	2.15	7.24	2.16	6.48	0.51	0.57	1.56	0.80	1.63	6.67	0.60	5.69
2001	2.20	7.30	2.05	5.99	0.54	0.64	1.48	0.82	1.66	6.66	0.56	5.17
2002	2.18	4.63	2.01	5.71	0.55	0.62	1.49	0.93	1.63	4.01	0.53	4.78
2003	2.15	6.37	1.98	6.86	0.55	0.66	1.44	1.09	1.60	5.72	0.53	5.77
2004	2.23	6.40	1.93	6.52	0.57	0.55	1.41	0.98	1.66	5.85	0.53	5.54
2005	2.42	7.99	1.87	8.94	0.57	0.53	1.38	0.97	1.85	7.47	0.49	7.97
2006	2.52	6.91	1.90	10.31	0.59	0.54	1.42	1.38	1.93	6.37	0.49	8.93
2007	2.57	6.68	1.89	10.78	0.60	0.52	1.39	1.45	1.96	6.16	0.50	9.33
2008	2.80	7.80	1.96	17.63	0.60	0.53	1.46	1.94	2.20	7.27	0.51	15.69
2009	2.97	5.00	2.03	12.37	0.67	0.56	1.46	2.55	2.30	4.44	0.57	9.82

6. Hours of Operation

Hours of operation are calculated as the sum of hours in a year where the plant's zonal Locational Based Marginal Price (LBMP)[19] exceeds its Total Marginal Cost (TMC) of production. LBMP is defined as the value in dollars per megawatt-hour of energy injected into the grid at a particular location.[20] Plant LBMPs are reported by NY ISO's 15 zones. For a plant X in year Y in NY ISO zone k, the number of hours of operation is given by:

$$\text{Hours of operation}_{X,Y} = \sum_{i=1}^{8760} \text{LBMP}_{Y,k,i} > \text{TMC}_X$$

[17]Nuclear Energy Institute, Costs: Fuel, Operation and Waste Disposal at http://www.nei.org/resourcesandstats/nuclear_statistics/costs

[18]Nuclear Energy Institute, U.S. Electricity Costs and Production Components (1995-2009) at http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/graphicsandcharts/uselectricityproductioncostsandcomponents

[19]NYISO LBMP database at http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp

[20]NYISO technical bulletin 026, 12/5/2008 at http://www.nyiso.com/public/webdocs/documents/tech_bulletins/tb_062.pdf

Note that in the above equation the sum range will change from 8760 to 8784 for leap years. In 2008, Arthur Kill Generating Station, owned by NRG Energy and operating in NYISO zone J, operated 1640 out of 8784 hours.

Total Marginal Cost is defined as the sum of Marginal Fuel Cost and O&M costs. Marginal Fuel Cost is calculated as the product of fuel prices forecasted by the AEO 2010[21] and the plants' corresponding heat rates[22] O&Ms are the values reported in 2008 by the Nuclear Energy Institute.[23] Therefore, for a plant X in year Y the Total Marginal Cost is:

$$\text{TMC}_{X,Y} = \left(\text{Marginal Fuel Cost}_{X,Y}\right) + \left(\text{Marginal O\&M}_{X}\right)$$

TMC for Arthur Kill Generating Station in 2008 was equal to $128.25/MWh, where the Marginal Fuel Cost was $122.75/MWh and the O&M cost was $5.50/MWh. The formula for calculating the Marginal Fuel Price is given below in Section 8, Heat Rates.

We use the number of hours of operation to calculate the energy revenue, which is defined as the product of the number of hours of operation, the corresponding LBMP, and the nameplate capacity of the plant.[24] Total plant costs are also calculated as the product of the number of hours of operation, nameplate capacity, and the total marginal cost as defined above.

The maximum hours of operation of any plant is limited to the fraction of hours in a year equal to the Weighted Equivalent Availability Factor (WEAF) listed in the North American Electric Reliability Corporation Generating Availability Data System (GADS).[25] This factor takes into account the forced and scheduled outages that restrict the plants to operating for a smaller number of hours per year than may be economically desirable for them.

[21] AEO 2010, Electricity Generation & Renewable Resources: Table 77 Electric Power Projections for EMM Region Northeast Power Coordinating Council/ New York at http://www.eia.doe.gov/oiaf/aeo/supplement/index.htmlhttp://www.eia.doe.gov/oiaf/aeo/supplement/sup_elec.xls

[22] Data calculated from the EIA Form-923 Database (Form 923 is a combined form for reporting EIA-906, EIA-920, EIA-423, FERC-423, and EIA-767, i.e. heat and power, monthly costs and fuel quantity, and operation and design aspects) at http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html and http://www.eia.doe.gov/pub/electricity/f906920_2008.zip

[23] NEI Report, US Electricity Production Costs and Components (1995-2009) at http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/graphicsandcharts/uselectricityproductioncostsandcomponents/http://www.nei.org/filefolder/US_Electricity_Production_Costs_and_Components.xls

[24] EIA definition of nameplate capacity at http://www.eia.doe.gov/glossary/glossary_g.htm

[25] NERC GADS downloadable database at http://www.nerc.com/page.php?cid=4|43

7. Uplift and Ancillary Service Charges

Ancillary services for 2008 are calculated as the sum of all revenues (other than energy and capacity) listed in the Federal Energy Regulatory Commission's Electric Quarterly Reports for the operator and/or parent company of an individual plant. The FERC EQRs summarize market-based power sales, cost-based power stales, and transmission service by company for each quarter. [26,27]

In 2008 the ancillary revenue for Arthur Kill Generating Station was $47,512,707.81, and included revenues from Black Start Services, Reactive Supply and Voltage Control, Regulation and Frequency Response, Spinning Reserve, Supplemental Reserve, and Uplift payments.

Subsequent to 2008, ancillary services are calculated as the product of 2008 ancillary services, and the ratio of subsequent energy and capacity revenue to the 2008 energy and capacity revenue. Ancillary revenue for a plant X, in year Y, is given as:

$$\text{Ancillary Revenue}_{X,Y} = \text{Ancillary Revenue}_{2008}\left(\frac{\text{Energy and Capacity Revenue}_{X,Y}}{\text{Energy and Capacity Revenue}_{2008}}\right)$$

The forecasted ancillary revenue for Arthur Kill Generating Station in 2012 is calculated to be $45,438,105.53 using the formula above.

8. Heat Rates

Heat rate is a measure of plant efficiency expressed as the ratio of the total fuel consumption in MMBtus to net generation in MWhs. Total fuel consumption and net generation can be calculated from the AEO 2008.[28] Heat rates for all 25 plants are assumed to be constant from 2008 to 2035, based on the heat rates in 2008. The heat rate of a plant X in 2008 is given by:

$$\text{Heat Rate}_X = \frac{\text{Fuel Consumption MMBtu}_X}{\text{Net Generation}_X}$$

Heat rate is used to convert fuel prices given in the AEO 2010[29] from dollars per MMBtu to Dollars per MWh. The marginal fuel cost of a plant X, in year Y, is equal to:

[26] FERC EQR Accessing Data: http://eqrdds.ferc.gov/eqrdds/newapp/emailinfo.aspx
[27] FERC EQR Description: http://www.ferc.gov/docs-filing/eqr.asp
[28] Data calculated from EIA Form-923 Database at http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html And http://www.eia.doe.gov/pub/electricity/f906920_2008.zip
[29] AEO 2010, Electricity Generation & Renewable Resources: Table 77 Electric Power Projections for EMM Region Northeast Power Coordinating Council/ New York at

$$\text{Marginal Fuel Cost}_{X,Y} = (\text{Heat Rate}_X)(\text{EIA Fuel Price}_Y)$$

We adjust the heat rate to reflect a 3% increase as a result of the installation of a closed cycle cooling system.

9. LBMP Calculation

We forecast the plants' energy revenues between 2010 and 2035 using the EIA's annual electricity generation price forecasts for the New York region between 2008 and 2035.[30] The EIA's price estimates are renormalized using the actual hourly electricity prices recorded at the New York ISO in 2008.[31] From that point on, the NY ISO prices by zone in 2008 are assumed to grow at the annual rates forecasted by the EIA until 2035.

The energy revenues are calculated by multiplying the forecasted hourly prices by the plants' average available generating capacities and estimated number of hours of operation in each year (see above).

Results

Our results indicate that only one of the 25 operating plants will be closed by compliance with the closed cycle cooling requirement alone. Our results agree with the analysis in the draft of the BTA policy's Appendix A that the unit most threatened by environmental compliance is the Oswego Steam Station.

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http://www.eia.doe.gov/oiaf/aeo/supplement/index.htmlhttp://www.eia.doe.gov/oiaf/aeo/supplement/sup_elec.xls

[30] AEO 2010, New York Prices by Time Slice.

[31] NY ISO Day-Ahead Market Locational-based Marginal Prices (Zonal) for 2008 at http://mis.nyiso.com/public/P-2Alist.htm

Table 2: Forecasted Impact of Closed Cycle Cooling System Implementation on Steam Plants in New York State

Facility Name	Result	Calculated Capacity Factor	Actual 2008 Capacity Factor	Nameplate Capacity (MW) Reduced By	NYISO Zone	Heat Rate (Btu/kwh)	WEAF	Fuel Name	Real Tax-Adjusted Discount Rate	Net Present Value of 2010-2035 Net Income	CCC Capital Costs
AES Cayuga	Open	85.15%	79.27%	312.83	C	$ 10,249.42	85.20%	Coal	4.69%	$930,395,539.55	$84,406,250.00
AES Greenidge LLC	Open	84.80%	51.32%	157.14	C	$ 10,995.45	85.03%	Coal	4.69%	$457,362,000.30	$43,552,083.00
AES Somerset LLC	Open	83.56%	93.28%	635.45	A	$ 9,444.68	83.96%	Coal	4.69%	$1,722,484,742.03	$107,346,250.00
AES Westover	Open	84.78%	48.87%	115.24	C	$ 11,030.17	85.03%	Coal	4.69%	$333,546,503.42	$39,258,542.00
Arthur Kill Generating Station	Open	32.65%	14.81%	903.75	J	$ 11,706.61	87.70%	Natural Gas	2.84%	$3,329,899,532.32	$274,956,250.00
Astoria Generating Station	Open	31.84%	18.99%	1,305.62	J	$ 11,847.69	87.70%	Natural Gas	1.76%	$5,724,217,072.30	$540,431,250.00
Black River Generation	Open	85.86%	98.25%	53.35	E	$ 12,560.73	85.88%	Coal	3.09%	$267,258,892.09	$21,197,917.00
Bowline Point	Open	14.46%	2.20%	1,076.70	G	$ 13,164.48	87.70%	Natural Gas	2.93%	$1,085,149,217.43	$351,553,558.00
Brooklyn Navy Yard Cogeneration	Open	35.10%	69.98%	312.34	J	$ 11,322.35	85.77%	Natural Gas	1.37%	$1,113,482,268.76	$21,197,917.00
C R Huntley Generating Station	Open	81.83%	65.22%	423.60	A	$ 10,261.42	83.04%	Coal	2.84%	$1,353,321,075.52	$325,904,479.00
Charles Poletti	Retired	2.88%	26.38%	898.22	J	$ 11,036.14	85.50%	Residual Fuel Oil	3.09%	$268,339,852.67	$239,617,396.00
Danskammer Generating Station	Open	83.04%	58.58%	521.28	G	$ 10,255.50	83.04%	Coal	1.67%	$3,246,748,135.89	$176,324,271.00
Dunkirk Generating Plant	Open	80.89%	77.54%	543.69	A	$ 10,614.62	83.04%	Coal	2.84%	$2,079,915,393.10	$222,971,250.00
E F Barrett	Open	37.77%	20.16%	666.58	K	$ 11,682.40	80.46%	Natural Gas	3.07%	$1,648,055,155.75	$113,447,396.00
East River	Open	33.99%	45.89%	708.29	J	$ 11,492.47	80.46%	Natural Gas	1.37%	$2,322,608,778.17	$122,177,083.00
Far Rockaway	Open	36.63%	7.36%	213.40	K	$ 11,830.26	85.60%	Natural Gas	3.07%	$633,698,254.22	$32,182,292.00
Glenwood	Open	25.33%	2.65%	446.20	K	$ 13,345.53	84.10%	Natural Gas	3.07%	$837,464,400.34	$66,939,167.00
Indian Point	Open	88.50%	86.02%	2,301.20	H	$ 10,488.00	88.50%	Uranium	2.31%	$16,985,767,917.81	$1,079,451,875.00
James A Fitzpatrick	Open	89.86%	89.03%	855.54	C	$ 10,488.00	89.86%	Uranium	2.31%	$5,269,139,592.64	$240,153,125.00
Nine Mile Point Nuclear Station	Open	88.50%	88.82%	1,844.07	C	$ 10,488.00	88.50%	Uranium	4.17%	$8,009,429,228.75	$188,723,125.00
Northport	Open	46.27%	33.71%	1,517.08	K	$ 10,621.06	87.70%	Natural Gas	3.07%	$4,464,617,914.75	$361,728,958.00
Oswego Harbor Power	Closed	0.09%	0.60%	1,751.72	C	$ 11,816.14	85.50%	Residual Fuel Oil	2.84%	$470,840,047.82	$539,120,833.00
Port Jefferson	Open	40.64%	19.42%	568.42	K	$ 11,320.95	84.10%	Natural Gas	3.07%	$1,975,570,474.01	$153,704,167.00
R. E. Ginna Nuclear Power Plant	Open	84.43%	90.94%	593.74	B	$ 10,488.00	84.43%	Uranium	4.17%	$2,280,800,918.43	$188,923,542.00
Ravenswood	Open	46.23%	15.89%	2,546.25	J	$ 9,691.71	87.70%	Natural Gas	3.39%	$8,890,771,988.49	$536,076,042.00
Roseton Generating Station	Open	1.60%	4.22%	1,204.74	G	$ 10,826.74	85.50%	Residual Fuel Oil	1.67%	$505,361,591.18	$356,807,188.00
Russell	Retired	81.84%	0.10%	2,450.22	B	$ 10,592.17	82.24%	Coal	2.86%	$8,686,256,419.85	$48,285,000.00

The results are quite robust under a variety of modeling values. For example, even under the cap and trade assumptions discussed below, the capital costs of environmental compliance would not cause an additional closure unless increased by 41%.

Economic Implications of the Closure of the Oswego Steam Station

The load resource balance in New York is summarized in Table V-2a of the 2010 Gold Book.[32] The Gold Book, an annual reference document prepared by the New York ISO, includes information on system loads, specific generating resources, load resource balance, and transmission.

Table 3: New York Control Area Load / Resource Balance Forecast

		MEGAWATT											
	SUMMER CAPABILITY	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Totals**
Fossil	Steam Turbine (Oil)	1685.5	1685.5	1685.5	1685.5	1685.5	1685.5	1685.5	1685.5	1685.5	1685.5	1685.5	
	Steam Turbine (Oil & Gas)	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	
	Steam Turbine (Gas)	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	
	Steam Turbine (Coal)	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	
	Combined Cycle	7996.4	8655.4	8655.4	8655.4	8655.4	8655.4	8655.4	8655.4	8655.4	8655.4	8655.4	
	Jet Engine (Oil)	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	
	Jet Engine (Gas & Oil)	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	
	Combustion Turbine (Oil)	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	
	Combustion Turbine (Oil & Gas)	1573.8	1573.8	2086.3	2086.3	2086.3	2086.3	2086.3	2086.3	2086.3	2086.3	2086.3	
	Combustion Turbine (Gas)	1207.8	1207.8	1757.8	1849.0	1849.0	1849.0	1849.0	1849.0	1849.0	1849.0	1849.0	
	Internal Combustion	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	
Pumped Storage	Pumped Storage Hydro	1376.6	1406.6	1406.6	1406.6	1406.6	1406.6	1406.6	1406.6	1406.6	1406.6	1406.6	
Nuclear	Steam (PWR Nuclear)	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	
	Steam (BWR Nuclear)	2628.1	2628.1	2628.1	2796.1	2796.1	2796.1	2796.1	2796.1	2796.1	2796.1	2796.1	
Renewable (5)	Conventional Hydro	4177.0	4177.0	4177.0	4177.0	4177.0	4177.0	4177.0	4177.0	4177.0	4177.0	4177.0	
	Internal Combustion (Methane)	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	
	Steam Turbine (Wood)	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	
	Steam Turbine (Refuse)	245.7	245.7	245.7	245.7	245.7	245.7	245.7	245.7	245.7	245.7	245.7	
	Wind (6)	124.1	124.1	125.6	125.6	125.6	126.2	126.2	126.2	126.2	126.2	126.2	
	EXISTING GENERATING FACILITIES	37415.8	38104.8	39168.8	39428.0	39428.0	39428.6	39428.6	39428.6	39428.6	39428.6	39428.6	
	Special Case Resources - SCR (3)	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	
Changes	Additions	659.0	1064.0	91.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**1814.2**
	Reratings	30.0	0.0	168.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	**198.6**
	Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
	NYCA RESOURCE CAPABILITY	40355.8	41419.8	41679.0	41679.0	41679.6	41679.6	41679.6	41679.6	41679.6	41679.6	41679.6	
Contracts	Net Purchases and Sales (1) (7)	1541.9	1228.2	1260.6	1951.6	1901.6	1901.6	1901.6	1901.6	1901.6	1901.6	1901.6	
	TOTAL RESOURCE CAPABILITY	41897.7	42648.0	42939.6	43630.6	43581.2	43581.2	43581.2	43581.2	43581.2	43581.2	43581.2	
	BASE FORECAST												
	Peak Demand Forecast	33025.1	33160.5	33367.3	33736.9	33897.0	34021.0	34193.1	34414.3	34672.3	34985.8	35333.7	
	Expected Reserve	8872.6	9487.5	9572.3	9893.7	9684.2	9560.2	9388.1	9166.9	8908.9	8595.4	8247.5	
	Reserve Margin % (4)	26.9	28.6	28.7	29.3	28.6	28.1	27.5	26.6	25.7	24.6	23.3	
	Proposed Resource Changes (2)	3.2	136.0	978.7	1637.6	1663.7	1558.4	1558.4	1558.4	1558.4	1558.4	1558.4	
	Adjusted Resource Capability	41900.9	42784.0	43918.3	45268.2	45244.9	45139.6	45139.6	45139.6	45139.6	45139.6	45139.6	
	Adjusted Expected Reserve	8875.8	9623.5	10550.9	11531.3	11347.9	11118.5	10946.4	10725.3	10467.3	10153.8	9805.9	
	Adjusted Reserve Margin %	26.9	29.0	31.6	34.2	33.5	32.7	32.0	31.2	30.2	29.0	27.8	

The purpose of this table is to estimate whether the capacity resources in New York are sufficient to meet projected requirements. The structure of the table itemizes and totals all generating facilities.

[32] 2010 Load & Capacity Data, New York Independent System Operator, April 2010, page 72.

The resource capability is compared to the base forecast. Finally, the reserve margin for New York is calculated.

Although the estimates of acceptable reserve margins vary by jurisdiction, the acceptable range is 7% to 15%. The lowest estimate in the 2010 Gold Book is a reserve margin of 26.9% in 2010. This is highlighted in yellow.

The Oswego Steam Station is the first resource in Table V-2a. It is quite easy to recalculate this table assuming that this unit is retired in 2010. We also assume a 3% reduction in the capacity of plants which have implemented closed cycle cooling systems.

Table 4: New York Control Area Load / Resource Balance Forecast Without Oswego Steam Station

		MEGAWATT										
	SUMMER CAPABILITY	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Fossil	Steam Turbine (Oil)	0	0	0	0	0	0	0	0	0	0	0
	Steam Turbine (Oil & Gas)	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8	7962.8
	Steam Turbine (Gas)	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3	1257.3
	Steam Turbine (Coal)	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1	2620.1
	Combined Cycle	7996.4	8655.4	8655.4	8655.4	8655.4	8655.4	8655.4	8655.4	8655.4	8655.4	8655.4
	Jet Engine (Oil)	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9
	Jet Engine (Gas & Oil)	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1
	Combustion Turbine (Oil)	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8	1003.8
	Combustion Turbine (Oil & Gas)	1573.8	1573.8	2086.3	2086.3	2086.3	2086.3	2086.3	2086.3	2086.3	2086.3	2086.3
	Combustion Turbine (Gas)	1207.8	1207.8	1757.8	1849	1849	1849	1849	1849	1849	1849	1849
	Internal Combustion	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1
Pumped Storage	Pumped Storage Hydro	1376.6	1406.6	1406.6	1406.6	1406.6	1406.6	1406.6	1406.6	1406.6	1406.6	1406.6
Nuclear	Steam (PWR Nuclear)	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9	2643.9
	Steam (BWR Nuclear)	2628.1	2628.1	2628.1	2796.1	2796.1	2796.1	2796.1	2796.1	2796.1	2796.1	2796.1
Renewable	Conventional Hydro	4177	4177	4177	4177	4177	4177	4177	4177	4177	4177	4177
	Internal Combustion (Methane)	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7
	Steam Turbine (Wood)	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1
	Steam Turbine (Refuse)	245.7	245.7	245.7	245.7	245.7	245.7	245.7	245.7	245.7	245.7	245.7
	Wind (6)	124.1	124.1	125.6	125.6	125.6	126.2	126.2	126.2	126.2	126.2	126.2
	EXISTING GENERATING FACILITIES	35730.3	36419.3	37483.3	37742.5	37742.5	37743.1	37743.1	37743.1	37743.1	37743.1	37743.1
	Special Case Resources - SCR (3)	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0	2251.0
Changes	Additions	659.0	1064.0	91.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CCC Capacity Decrease	-699.0	-699.0	-699.0	-699.0	-699.0	-699.0	-699.0	-699.0	-699.0	-699.0	-699.0
	Reratings	30.0	0.0	168.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0
	Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	NYCA RESOURCE CAPABILITY	37971.3	39035.3	39294.5	39294.5	39295.1	39295.1	39295.1	39295.1	39295.1	39295.1	39295.1
Contracts	Net Purchases and Sales (1) (7)	1541.9	1228.2	1260.6	1951.6	1901.6	1901.6	1901.6	1901.6	1901.6	1901.6	1901.6
	TOTAL RESOURCE CAPABILITY	39513.2	40263.5	40555.1	41246.1	41196.7	41196.7	41196.7	41196.7	41196.7	41196.7	41196.7
	BASE FORECAST											
	Peak Demand Forecast	33025.1	33160.5	33367.3	33736.9	33897.0	34021.0	34193.1	34414.3	34672.3	34985.8	35333.7
	Expected Reserve	6488.1	7103.0	7187.8	7509.2	7299.7	7175.7	7003.6	6782.4	6524.4	6210.9	5863.0
	Reserve Margin % (4)	19.6	21.4	21.5	22.3	21.5	21.1	20.5	19.7	18.8	17.8	16.6
	Proposed Resource Changes (2)	3.2	136.0	978.7	1637.6	1663.7	1558.4	1558.4	1558.4	1558.4	1558.4	1558.4
	Adjusted Resource Capability	39516.4	40399.5	41533.8	42883.7	42860.4	42755.1	42755.1	42755.1	42755.1	42755.1	42755.1
	Adjusted Expected Reserve	6491.3	7239.0	8166.5	9146.8	8963.4	8734.1	8562.0	8340.8	8082.8	7769.3	7421.4
	Adjusted Reserve Margin %	19.7	21.8	24.5	27.1	26.4	25.7	25.0	24.2	23.3	22.2	21.0

The revised table indicates that there is no problem meeting a prudent reserve margin in New York after the Oswego Steam Station is retired. The details from AEO 2010 corroborate the retirements in the oilpowered steam category, but are not reported on a unit by unit basis. For example, Table 77, Electric Power Projections for EMM Region New York, indicates an 850 megawatt retirement in 2010.[33]

The energy implications of the Oswego Steam Plant closure are also inconsequential. In 2008, the capacity factor of this unit was only 6/10ths of 1%. Overall, our modeling indicates that it would be dispatched at 1/10 of 1% over the next 25 years.

The Economic Impact of Parasitic Losses

We use 3% as an estimate of the parasitic losses associated with the adoption of the closed cycle cooling equipment.

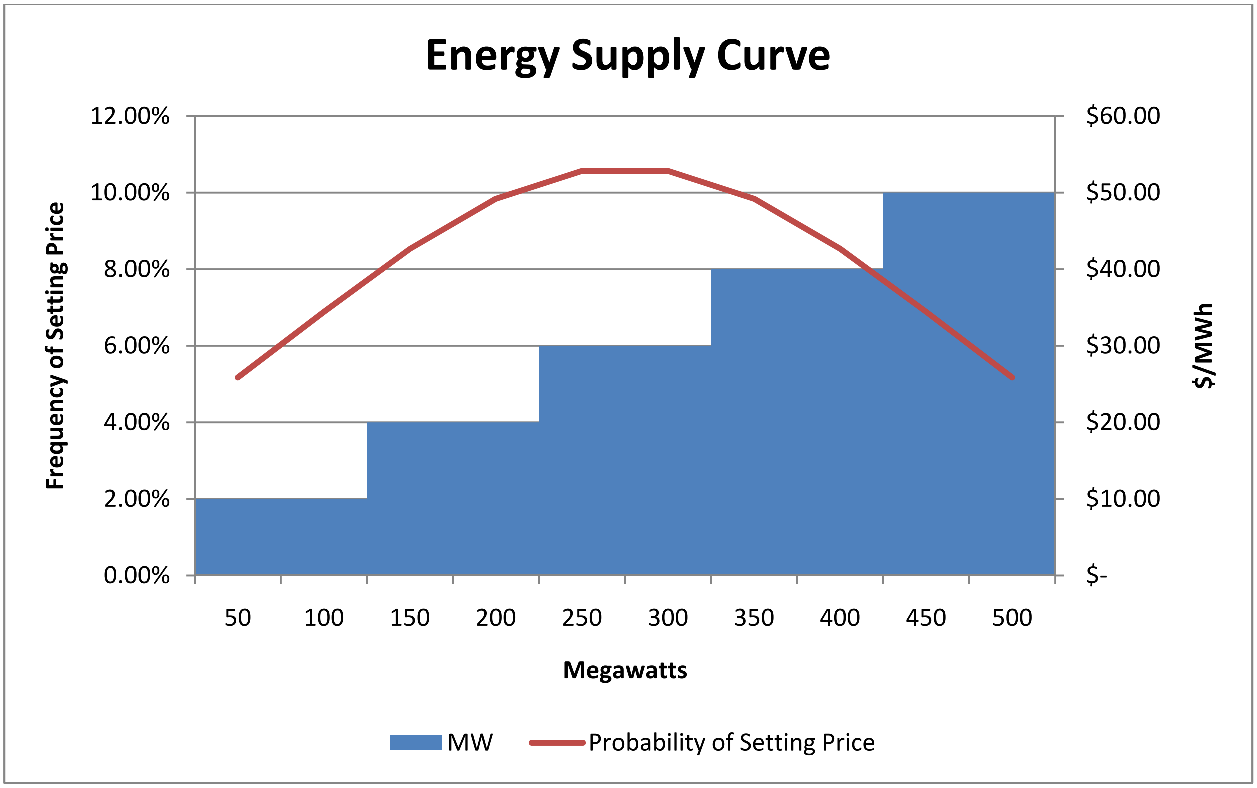
This increase in the marginal cost of the 25 units will only affect prices during the brief periods in a year when these units are on the economic margin. Unfortunately, there is incomplete information on how often the 25 units are price-setters. In 2008, the highest demand in New York was 32,432 megawatts versus a total resource capability of 40,554,4.[34,35] Of the 40,554.4 megawatts available to meet demand, 25,697.6 megawatts were provided by plants identified in the CP-nn / Best Technology Available (BTA) for Cooling Water Intake Structures policy.

Economic theory leads us to presume the placement of a plant in the dispatch order will be based on its marginal cost. The chart below shows a hypothetical energy supply curve based on five power plants – each with a capacity of 100 megawatts:

[33] AEO 2010, Electricity Generation & Renewable Resources: Table 77 Electric Power Projections for EMM Region Northeast Power Coordinating Council/ New York at http://www.eia.doe.gov/oiaf/aeo/supplement/index.htmlhttp://www.eia.doe.gov/oiaf/aeo/supplement/sup_elec.xls

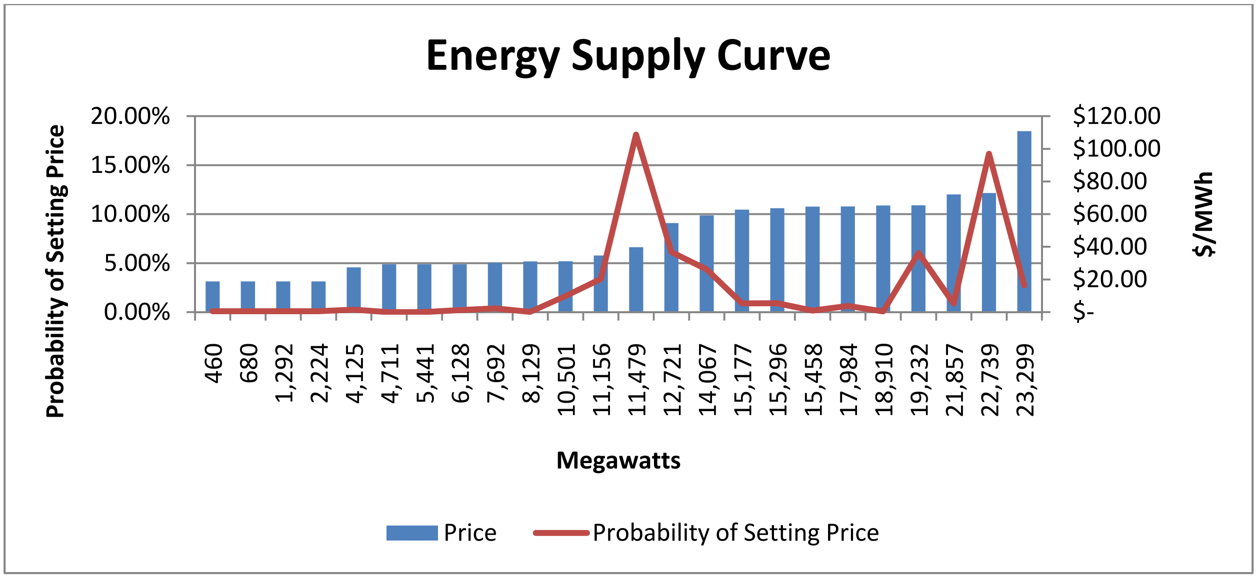
[34] 2010 Gold Book, page 20.

[35] 2008 Gold Book, page 66.



If the energy demand is 300 megawatts, the price setting unit would be the one whose marginal cost is $30/MWh. Small shanges in marginal costs for other units will not affect prices. There will be no impact on price for the fourth and fifth plants since their energy is not called upon. By the same token, the first two plants' marginal costs will not have an impact on price, since it is the third plant whose bid sets the market price. If demand follows the usual bell-shaped curve, the plants on the tails of the distribution wil have a smaller chance of setting the price. In the chart above, the third plant with a marginal cost of $30.00/MWh will set the price 40.7% of the year. The fifth plant will only set prices 14.2% of the year.

Extending this approach to marginal costs and prices experienced in 2010 produces the following chart:



Prices in New York are *not* normally distributed. The chart shows that the probability of setting prices varies dramatically between units. Units with low marginal costs, i.e. New York's nuclear stations, are seldom on the margin, so the 3% increase in their marginal costs will have little impact on market prices. By the same token, many of the plants with high marginal costs rarely set market prices, so their impact is minimal as well.

Weighting the incremental marginal cost by the probability that each specific plant will set prices at the New York ISO indicates that the impact on energy prices in New York will be slightly less than $1/MWh in 2010. The most recent data on electric prices indicates that consumers paid $151.70/MWh in February 2010.[36] The impact on consumers will be less than 1%.

Cap and Trade, CLEAR, or EPA Rule Impacts

The current state of public policy on carbon emissions is in some disarray. Recent press reports indicate that the Kerry Lieberman bill is unlikely to pass in 2010.[37] Even if passed, the bill is unclear on the operation of the mechanics; hence, modeling its impact on New York is problematic. Similarly, other rules in progress could require additional investment, particularly for coal-fired plants. Given the potential impact on the units under study that are fueled by coal is important, however. Because a prudent entrepreneur would evaluate both the cost of environmental upgrades and the potential for a significant surcharge on carbon in deciding whether to keep a plant open, we explore a scenario that

[36]See http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_a.html

[37]"Senate Gets a Climate and Energy Bill, Modified by a Gulf Spill That Still Grows", *The New York Times,* May 12, 2010 at http://www.nytimes.com/2010/05/13/science/earth/13climate.html

assumes that the price of coal will approximate the price of natural gas under cap and trade or one of its alternatives. This effectively more than doubles the cost of fuel to the coal units.

Given our assumption, an additional unit, C.R. Huntley, would close. The combination of a significant surcharge to fuel costs for carbon, plus the implementation of a closed cycle cooling system, reduces the expected income of this plant – net cooling capital and O&M expense – to less than zero.

Repowering or replacing C.R. Huntley with a comparable combined cycle natural gas plant would result in decreased air emissions and would generate 51% fewer CO_2 emissions, from 2,073,693 tons in 2009, to 1,017,194 tons annually.[38] SO_2 emissions would decrease 99%, from 6,018 tons in 2009, to 5 tons annually and NO_x emissions would decrease 88%, from 1,541 tons to 192 tons annually.[39] These results appear in Table 5.

Table 5: Repowering C.R. Huntley emissions data

Plant	CO_2 Mass (tons)	SO_2 Mass (tons)	No_x Mass (tons)
C.R. Huntley 2009	2,073,693	6,018	1,541
Natural Gas Combined Cycle	1,017,194	5	192

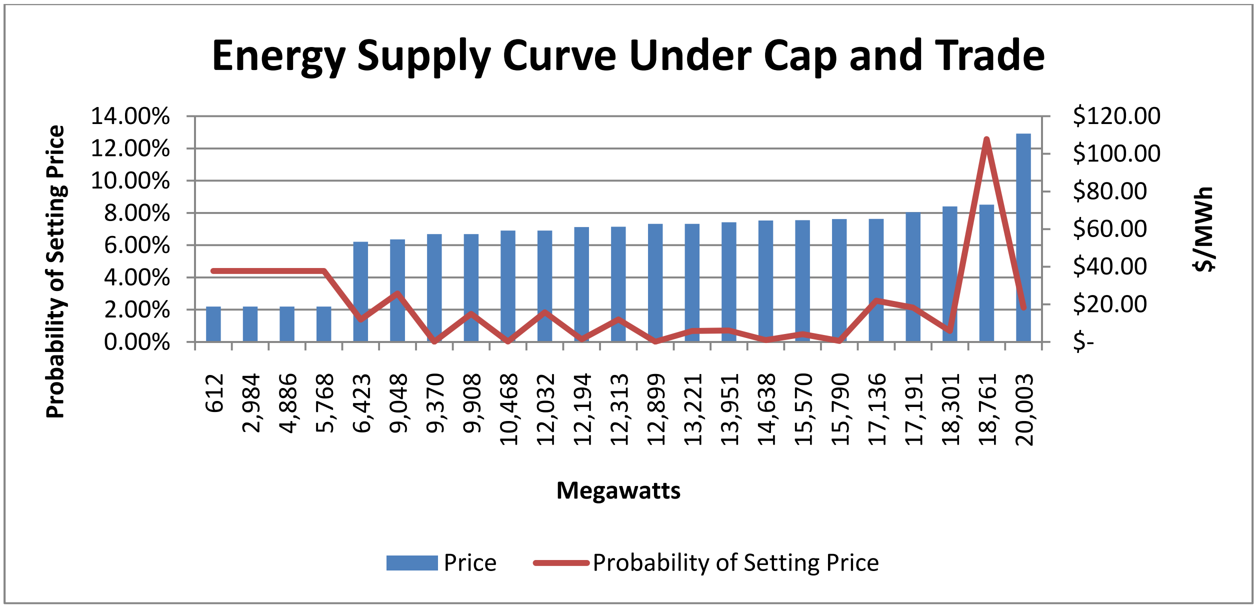
As a result of repowering C.R. Huntley, total emissions of CO_2, SO_2 and NO_x from the 25 plants studied would drop 4%, 15%, and 7%, respectively from their 2009 levels.

[38]Emissions Calculations are based on 2009 EPA data on emissions from combined cycle natural gas plants that came on-line in 2008; see http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard
[39]The change in SO_2 and NO_x emissions, while dramatic, is consistent with a combined cycle natural gas plant; see http://docs.google.com/viewer?a=v&q=cache:hhoExZMt2RoJ:www.netl.doe.gov/energy-analyses/pubs/deskreference/B_NGCC_051507.pdf+SO2+combined+cycle&hl=en&gl=us&pid=bl&srcid=ADGEESgthw4Pa5e03-wXo1Dc1PIiMKzaPimeGlfBnA0W9fyl5irFAqXzc3lrmK3bp_eMyx3AacKk2Paaf0RDBdEOGE5HGhUPjELGbTrZgh2WULFEFifPZrTG5xozyd-g0cwVgFfoIsPN&sig=AHIEtbTBFNPxMs9MN84byGbnZiZi1rc_cQ

Table 6: Forecasted Impact of Closed Cycle Cooling System Implementation on Steam Plants in New York State Under the Cap and Trade Scenario

Facility Name	Result	Calculated Capacity Factor	Nameplate Capacity (MW) Reduced By	NYISO Zone	Heat Rate (Btu/kwh)	WEAF	Fuel Name	Real Tax-Adjusted Discount Rate	Net Present Value of 2010-2035 Net Income	CCC Capital Costs
AES Cayuga	Open	12.01%	312.83	C	$ 10,249.42	85.20%	Cap and Trade	4.69%	$173,140,019.00	$84,406,250.00
AES Greenidge LLC	Open	8.88%	157.14	C	$ 10,995.45	85.03%	Cap and Trade	4.69%	$72,326,689.95	$43,552,083.00
AES Somerset LLC	Open	9.93%	635.45	A	$ 9,444.68	83.96%	Cap and Trade	4.69%	$312,159,912.82	$107,346,250.00
AES Westover	Open	8.76%	115.24	C	$ 11,030.17	85.03%	Cap and Trade	4.69%	$50,903,724.90	$39,258,542.00
Arthur Kill Generating Station	Open	32.65%	903.75	J	$ 11,706.61	87.70%	Natural Gas	2.84%	$3,329,899,532.32	$274,956,250.00
Astoria Generating Station	Open	31.84%	1,305.62	J	$ 11,847.69	87.70%	Natural Gas	1.76%	$5,724,217,072.30	$540,431,250.00
Black River Generation	Open	19.08%	53.35	E	$ 12,560.73	85.88%	Cap and Trade	3.09%	$69,078,084.61	$21,197,917.00
Bowline Point	Open	14.46%	1,076.70	G	$ 13,164.48	87.70%	Natural Gas	2.93%	$1,085,149,217.43	$351,553,558.00
Brooklyn Navy Yard Cogeneration	Open	35.10%	312.34	J	$ 11,322.35	85.77%	Natural Gas	1.37%	$1,113,482,268.76	$21,197,917.00
C R Huntley Generating Station	Closed	6.79%	423.60	A	$ 10,261.42	83.04%	Cap and Trade	2.84%	$176,059,894.16	$325,904,479.00
Charles Poletti	Retired	2.88%	898.22	J	$ 11,036.14	85.50%	Residual Fuel Oil	3.09%	$268,339,852.67	$239,617,396.00
Danskammer Generating Station	Open	32.28%	521.28	G	$ 10,255.50	83.04%	Cap and Trade	1.67%	$1,344,114,035.01	$176,324,271.00
Dunkirk Generating Plant	Open	5.77%	543.69	A	$ 10,614.62	83.04%	Cap and Trade	2.84%	$597,410,741.01	$222,971,250.00
E F Barrett	Open	37.77%	666.58	K	$ 11,682.40	80.46%	Natural Gas	3.07%	$1,648,055,155.75	$113,447,396.00
East River	Open	33.99%	708.29	J	$ 11,492.47	80.46%	Natural Gas	1.37%	$2,322,608,778.17	$122,177,083.00
Far Rockaway	Open	36.63%	213.40	K	$ 11,830.26	85.60%	Natural Gas	3.07%	$633,698,254.22	$32,182,292.00
Glenwood	Open	25.33%	446.20	K	$ 13,345.53	84.10%	Natural Gas	3.07%	$837,464,400.34	$66,939,167.00
Indian Point	Open	88.50%	2,301.20	H	$ 10,488.00	88.50%	Uranium	2.31%	$16,985,767,917.81	$1,079,451,875.00
James A Fitzpatrick	Open	89.86%	855.54	C	$ 10,488.00	89.86%	Uranium	2.31%	$5,269,139,592.64	$240,153,125.00
Nine Mile Point Nuclear Station	Open	88.50%	1,844.07	C	$ 10,488.00	88.50%	Uranium	4.17%	$8,009,429,228.75	$188,723,125.00
Northport	Open	46.27%	1,517.08	K	$ 10,621.06	87.70%	Natural Gas	3.07%	$4,464,617,914.75	$361,728,958.00
Oswego Harbor Power	Closed	0.09%	1,751.72	C	$ 11,816.14	85.50%	Residual Fuel Oil	2.84%	$470,840,047.82	$539,120,833.00
Port Jefferson	Open	40.64%	568.42	K	$ 11,320.95	84.10%	Natural Gas	3.07%	$1,975,570,474.01	$153,704,167.00
R. E. Ginna Nuclear Power Plant	Open	84.43%	593.74	B	$ 10,488.00	84.43%	Uranium	4.17%	$2,280,800,918.43	$188,923,542.00
Ravenswood	Open	46.23%	2,546.25	J	$ 9,691.71	87.70%	Natural Gas	3.39%	$8,890,771,988.49	$536,076,042.00
Roseton Generating Station	Open	1.60%	1,204.74	G	$ 10,826.74	85.50%	Residual Fuel Oil	1.67%	$505,361,591.18	$356,807,188.00
Russell	Retired	8.17%	2,450.22	B	$ 10,592.17	82.24%	Cap and Trade			

At higher fuel costs, the affected coal units are on the margin for fewer hours over the year. This reduces the wholesale price impact on consumers significantly.



After assuming that coal prices per mmbtu equal natural gas prices, the 2010 impact on wholesale prices is only $.76/MWh.

Renewable Portfolio Standards

In 2004 the New York Public Service Commission issued a renewable portfolio standard (RPS) with the goal of increasing the percentage of electricity from renewable sources to at least 25% by the end of 2013.[40] As of 2009 more than 1,164 MW of renewable capacity had been contracted, as evidenced by the additional generation capacity cited by the 2010 NYISO Gold Book.[41] This program is funded by a premium charged to electricity customers. NY PSC specified an escalating annual collection schedule totaling $741.5 million. One possible effect of the closure of the Oswego plant (as well as the Huntley plant under the cap and trade scenario) would be to facilitate the achievement of the RPS goal by reducing the amount of available capacity. Since many renewable technologies provide low marginal cost energy, the increasing renewable sector is likely to reduce the rate impact to consumers.

[40] New York Renewable Portfolio Standard Program Evaluation Report, New York State Energy Research and Development Authority, 2009 at http://www.nyserda.org/Energy_Information/NY%20Renewable%20Portfolio%20Standard%20Program%20Evaluation%20Report%20%282009%20Review%29-FINAL.pdf

[41] 2010 Load & Capacity Data, New York Independent System Operator, April 2010, page 63.

Appendix A: Glossary

AEO: Annual Energy Outlook produced by U.S. Department of Energy's Energy Information Administration

Ancillary Services: Necessary services that must be provided in the generation and delivery of electricity. As defined by the Federal Energy Regulatory Commission, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and the economic dispatch of plants); contractual agreements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves)

Baseload: The minimum amount of electric power delivered or required over a given period of time at a steady rate

Baseload Capacity: The generating equipment normally operated to serve loads on an around-the-clock basis

Baseload Plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously; these units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs

Beta (β): Describes a particular asset's returns in relation to the financial market as a whole; an asset with a positive beta is generally positively correlated with the market

British Thermal Unit (BTU): Amount of heat required to increase the temperature of a pint of water (weighing exactly 16 ounces) by one degree Fahrenheit; describes both the amount of heat energy in fuels and the ability of appliances and air conditioning systems to produce heating or cooling

Cap and Trade: Program enacted to promote environmentally-friendly policies by mandating emissions; the emissions allowance is strictly controlled and must not exceed a predetermined cap amount; emissions permits are provided to businesses, and are capped by government; businesses are able to transfer these permits to other capped businesses if the business determines that it will not need all the permits provided

Capacity: Amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer

Capital Asset Pricing Model (CAPM): Standard model in finance that describes the relationship between expected return and risk of an asset

Carbon Tax: A direct tax on greenhouse gas emissions to encourage companies to curb their emissions and protect the environment

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines; the exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity; the process increases the efficiency of the electric generating unit

Combined Cycle Unit: An electric generating unit consisting of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust gas of the combustion turbine(s)

Cost of Capital: Cost of obtaining capital for long-term investment in plant and equipment; the cost of obtaining it is usually expressed as a percentage of the amount of capital obtained

Cost of Debt: Average annual rate at which a company pays out interest on its total outstanding long-term debt, i.e. the ratio of its total interest expenditures in a given year to its total outstanding long-term debt in that year

Cost of Equity: The market required rate of return on a company's outstanding shares

Day-Ahead Market: The forward market for energy and ancillary services to be supplied during the settlement period of a particular trading day that is conducted by the Independent System Operator, the power exchange, and other scheduling coordinators; the market closes with the ISO's acceptance of the final day-ahead schedule

Day-Ahead Schedule: A schedule prepared by a scheduling coordinator or the ISO before the beginning of a trading day; this schedule indicates the levels of generation and demand scheduled for each settlement period that trading day

Distribution Cost: The cost of distributing electricity to the ultimate consumer

Electric Quarterly Report (EQR): Quarterly reports filed at FERC by public utilities and power marketers that summarize the contractual terms and conditions for market-based power sales, cost-based power sales, and transmission services

Federal Energy Regulatory Commission (FERC): A quasi-independent regulatory agency within the U.S. Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification

Fuel Costs (Fuel Expenses): Costs including the fuel used in the production of steam or driving another prime mover for the generation of electricity; other associated expenses include unloading the shipped fuel and all handling of the fuel up to the point where it enters the first bunker, hopper, bucket, tank, or holder in the boiler-house structure

Generator: A machine that converts mechanical energy into electrical energy; can also refer to the entire generation facility (also see Plant)

Grid: The layout of an electrical distribution system

Heat Rate: A measure of plant efficiency expressed as the ratio of the total fuel consumption in mmbtus to net generation in MWhs

Locational-based Marginal Price (LBMP): value in dollars per megawatt-hour of energy injected into the grid at a particular location

Marginal Cost: The variable costs of labor and materials and an estimated portion of fixed costs such as administration overheads and selling expenses

Marginal Fuel Cost: the product of fuel prices forecasted by the EIA and the plants' corresponding heat rates as calculated by the EIA

Megawatt (MW): One million watts

Megawatt-hour (MWh): One million watt hours

MMBtu (mmbtu): A thousand thousand BTUs

Nameplate Capacity: The rated output of a generator under specific conditions designed by the manufacturer (usually indicated on a physical nameplate attached to the generator)

New York Independent System Operator (NY ISO): The independent, non-profit organization that coordinates regional transmission in a non-discriminatory manner and ensures the safety and reliability of the electric system and that is regulated by the federal government (FERC)

North American Electric Reliability Corporation: The self-regulatory organization subject to oversight by FERC and governmental authorities in Canada that ensures the reliability of the bulk power system in North America

O&M: Self-explanatory; operations and maintenance is a term of industry

Outage: The period during which a generating unit, transmission line, or other facility is out of service, due to an emergency, maintenance, etc. (outages can also be scheduled)

Parasitic Loss: Reduction in energy and capacity caused by environmental compliance; in this case, the energy cost of closed cycle cooling equipment

Plant: A facility at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy; a plant may contain more than one type of prime mover; electric utility plants exclude facilities that satisfy the definition of a qualifying facility under the Public Utility Regulatory Policies Act of 1978

Power: The rate at which energy is transferred; electrical energy is usually measured in watts; also used for a measurement of capacity

Renewable Resources: Naturally, but flow-limited resources that can be replenished, and are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time; some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades, or perhaps centuries, they can probably be replenished; renewable energy resources include: biomass, hydro, geothermal, solar and wind; in the future, they could also include the use of ocean thermal, wave, and tidal action technologies; utility renewable resource applications include: bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies

Tax-Adjusted Real Discount Rate: The tax-adjusted interest rate at which an agent discounts future events in preferences in a multi-period model

Total Marginal Cost: The sum of Marginal Fuel Cost and O&M costs

Uplift payments: Payments made to ensure reliable and economic unit commitment

Watt: The electrical unit of power; the rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor

Weighted Average Cost of Capital (WACC): Cost of acquiring debt and/or equity capital, computed on the basis of interest rate, income tax rate, and return on equity goal; usually expressed as a percentage, it is used as a discount rate to determine present value of specific investments

Weighted Equivalent Availability Factor (WEAF): Maximum hours of operation of any plant is limited to the fraction of hours in a year equal to the Weighted Equivalent Availability Factor; Equivalent Availability Factor (EAF) is a weighted average of the percentage of full energy production capacity achievable

Zone: A defined region of a wholesale electricity market in which one price is set for electricity produced in that zone

From various sources including http://www.eia.doe.gov/cneaf/electricity/page/glossary.html