the previous 5 years prices was used to set the baseline prices, which were then adjusted for nominal value using the same GDP index used to adjust the fuel prices for future years.

3.4 Frequency Regulation Pricing

For frequency regulation prices, there are a number of factors that influence the market clearing prices. These include energy prices, regulation requirement (which changes from hour to hour and seasonally), as well as availability of regulation supply. Given the small size of the regulation market, the market has seen wide fluctuations in these prices over the past 5 years since introduction of the NYISO's SMD 2 Market Design. As a result, it was decided to use a Neural Network modeling technique to predict the forward regulation prices using the forecasted energy prices and anticipated regulation requirements based on wind penetration. Neural Network is an artificial intelligence process takes input and output through a decision process to train the software. Once trained the software can predict the output from the input data.

The NYISO also has carried out extensive analysis of potential impact of wind generation on regulation requirement (NYISO Growing Wind Final Report of the 2010 Wind Generation Study). The following tables show the proposed changes in regulation requirements in coming years as certain levels of Wind Generation penetration occurs in the NYISO grid. Cells in blue indicate hours when the regulation requirement is higher than the original NYISO requirements, and cells in orange indicate hours when the regulation requirement was reduced as it was expected that wind will contribute in reducing regulation requirements for those hours.

Study Year 2011 (34,768MW Peak Load)

2011	April - May			June - August			Sept - Oct			Nov - March		
HB	Current Weekday Regulation Requirement	Wind Level 3500MW	Wind Level 4250MW	Current Weekday Regulation Requirement	Wind Level 3500MW	Wind Level 4250MW	Current Weekday Regulation Requirement	Wind Level 3500MW	Wind Level 4250MW	Current Weekday Regulation Requirement	Wind Level 3500MW	Wind Level 4250MW
0	150	175	175	175	225	225	180	175	200	190	200	200
1	150	175	175	175	175	200	180	175	175	190	175	200
2	150	175	175	175	175	175	180	150	175	190	175	175
3	150	175	200	175	175	200	180	175	200	190	150	175
4	150	225	225	175	225	225	180	225	250	190	175	175
5	175	225	225	200	250	275	250	275	300	250	225	225
6	275	225	225	275	275	275	275	275	275	275	275	275
7	275	200	225	275	275	275	275	250	275	275	275	275
8	275	200	200	275	275	275	275	225	225	275	275	275
9	200	175	175	250	225	225	260	200	225	250	225	225
10	175	200	200	240	225	225	250	175	200	250	175	200
11	150	200	225	210	250	275	210	200	200	210	175	200
12	150	175	175	175	225	250	180	200	225	180	175	200
13	150	175	175	175	225	250	180	200	225	180	175	175
14	150	175	175	175	250	275	180	175	200	180	175	175
15	175	175	200	175	225	225	190	175	200	190	225	225
16	200	175	200	250	250	250	250	200	225	275	275	275
17	200	200	225	250	250	250	250	250	275	275	300	300
18	200	225	225	250	250	250	250	275	300	275	250	250
19	200	250	275	250	250	250	250	250	275	250	250	250
20	200	200	225	250	250	250	250	250	250	250	200	225
21	200	200	225	250	250	275	250	250	250	250	225	225
22	175	200	200	225	275	275	240	200	200	240	200	200
23	150	200	200	175	275	275	190	225	250	190	200	200

- **The weighted average across all hours for the year shows the regulation requirements increase in 2011 by: 5MW with 3500MW of wind, 14MW with 4250MW of wind**

Study Year 2013 (35,475MW Peak Load)

2013	April - May			June - August			Sept - Oct			Nov - March		
HB	Current Weekday Regulation Requirement	Wind Level 4250MW	Wind Level 6000MW	Current Weekday Regulation Requirement	Wind Level 4250MW	Wind Level 6000MW	Current Weekday Regulation Requirement	Wind Level 4250MW	Wind Level 6000MW	Current Weekday Regulation Requirement	Wind Level 4250MW	Wind Level 6000MW
0	150	175	200	175	225	275	180	200	225	190	200	225
1	150	175	225	175	200	250	180	200	225	190	200	250
2	150	175	200	175	175	225	180	175	200	190	175	225
3	150	225	250	175	200	225	180	225	250	190	175	200
4	150	275	300	175	250	275	180	275	300	190	225	250
5	175	300	325	200	275	300	250	325	350	250	275	300
6	275	250	275	275	300	325	275	275	300	275	325	350
7	275	250	250	275	275	275	275	275	300	275	275	300
8	275	200	250	275	275	275	275	225	275	275	275	275
9	200	225	250	250	225	275	260	225	250	250	225	275
10	175	225	250	240	225	275	250	175	225	250	200	275
11	150	200	225	210	275	275	210	200	250	210	225	300
12	150	200	250	175	250	300	180	200	250	180	200	250
13	150	225	275	175	225	275	180	200	250	180	200	225
14	150	200	250	175	275	325	180	200	225	180	175	200
15	175	225	275	175	250	300	190	200	225	190	225	250
16	200	175	225	250	250	325	250	225	250	275	275	300
17	200	200	250	250	250	325	250	275	300	275	300	325
18	200	225	275	250	250	275	250	275	325	275	250	275
19	200	275	325	250	250	300	250	275	325	250	250	325
20	200	225	275	250	275	325	250	250	300	250	225	275
21	200	225	275	250	250	325	250	250	275	250	225	275
22	175	225	250	225	275	325	240	225	250	240	250	300
23	150	225	250	175	275	325	190	250	275	190	200	250

- **The weighted average across all hours for the year shows the regulation requirements increase in 2013 by: 22MW with 4250MW of wind, 60MW with 6000MW of wind**

Study Year 2018 (37,130MW Peak Load)

2018	April - May			June - August			Sept - Oct			Nov - March		
HB	Current Weekday Regulation Requirement	Wind Level 6000MW	Wind Level 8000MW	Current Weekday Regulation Requirement	Wind Level 6000MW	Wind Level 8000MW	Current Weekday Regulation Requirement	Wind Level 6000MW	Wind Level 8000MW	Current Weekday Regulation Requirement	Wind Level 6000MW	Wind Level 8000MW
0	150	225	250	175	250	300	180	225	275	190	250	275
1	150	225	275	175	250	325	180	250	300	190	250	300
2	150	225	275	175	225	275	180	225	250	190	225	300
3	150	275	300	175	250	275	180	275	300	190	225	250
4	150	325	350	175	300	325	180	325	350	190	250	275
5	175	325	350	200	300	325	250	375	400	250	300	325
6	275	275	300	275	350	375	275	325	350	275	350	375
7	275	300	300	275	300	375	275	325	375	275	300	375
8	275	275	300	275	275	325	275	300	350	275	275	350
9	200	250	275	250	275	325	260	250	300	250	275	325
10	175	275	300	240	250	300	250	225	275	250	250	300
11	150	225	275	210	275	325	210	275	300	210	300	300
12	150	250	325	175	275	375	180	250	300	180	250	300
13	150	275	350	175	275	350	180	250	300	180	225	275
14	150	225	300	175	325	400	180	225	275	180	225	275
15	175	250	325	175	300	350	190	250	300	190	250	325
16	200	225	275	250	325	400	250	275	300	275	300	350
17	200	250	300	250	325	400	250	325	350	275	350	400
18	200	275	325	250	275	350	250	300	325	275	300	350
19	200	325	375	250	300	375	250	325	375	250	325	400
20	200	275	325	250	350	425	250	300	375	250	300	375
21	200	275	325	250	350	425	250	300	375	250	275	325
22	175	250	275	225	350	400	240	250	325	240	275	350
23	150	250	300	175	300	350	190	275	325	190	250	325

- **The weighted average across all hours for the year shows the regulation requirements increase in 2018 by: 66MW with 6000MW of wind, 116MW with 8000MW of wind**

Since the regulation requirement could change with the wind penetration levels, two regulation price forecasts were generated for the base case and high wind scenario. The chart below shows the differences in wind penetration level for the 2 scenarios.

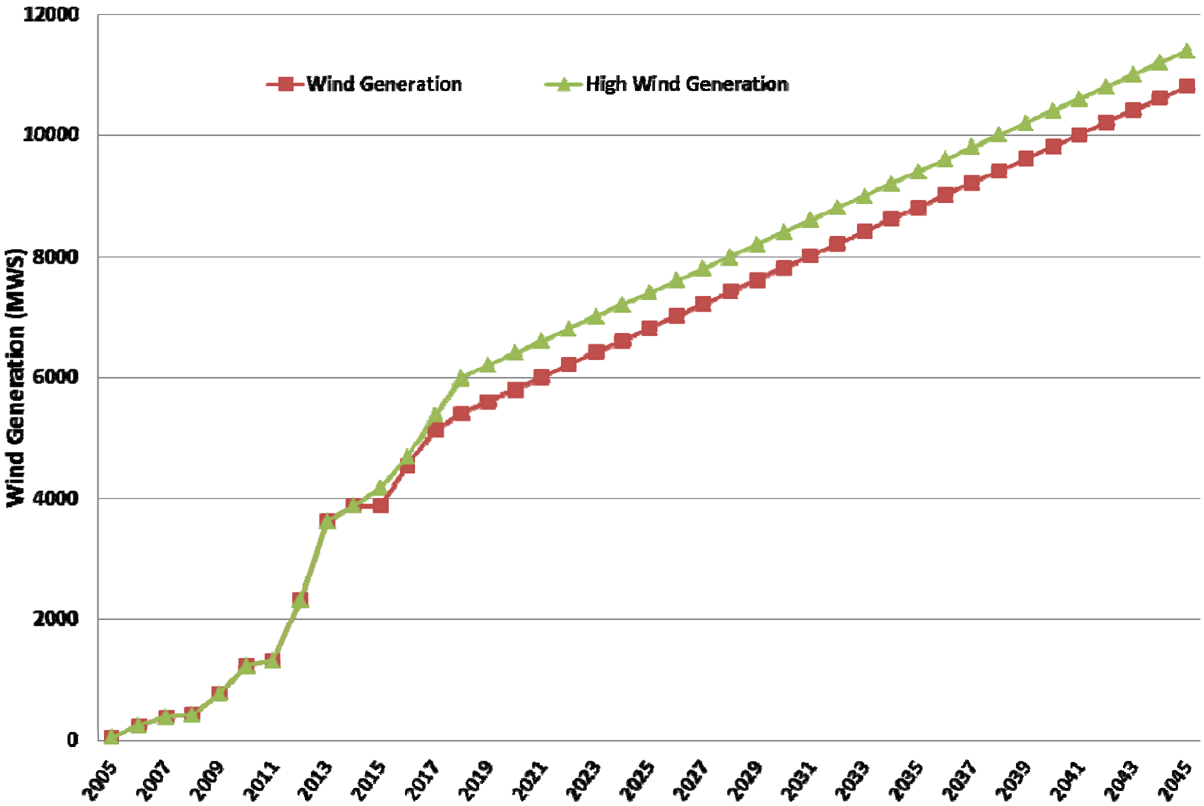

Figure 11: Wind penetration under base case and high wind scenario in NY

The chart below shows the difference in the average regulation prices between the base case and high wind scenarios. Since for most of the years the wind penetration level with in both scenarios falls under similar buckets for regulation requirements (i.e. 4.2 GW to 6 GW, 6 GW to 8 GW and 8 GW and above), the model predicts differences in the regulation prices only for 2027 – 32 period.

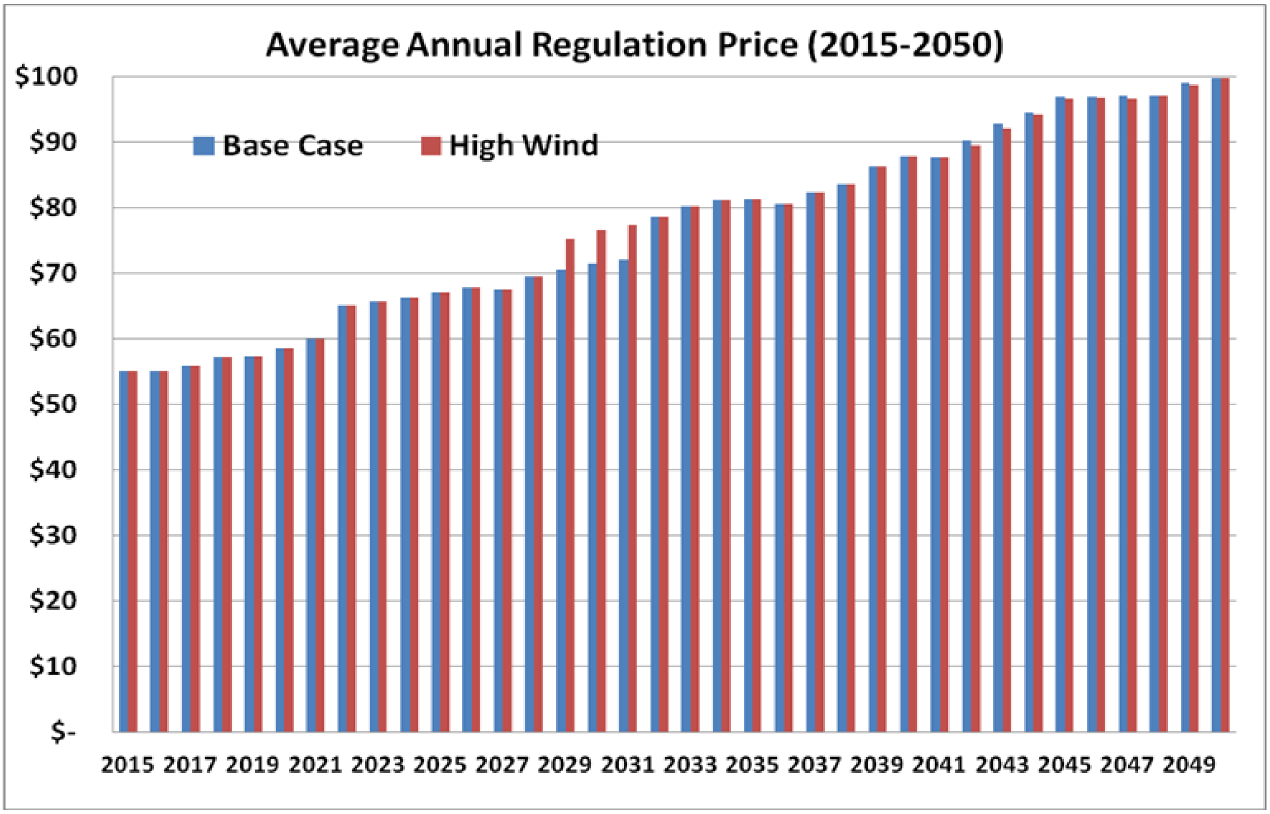

Figure 12: Average Regulation Prices for base case and high wind scenario

3.5 Capacity Price Forecasting

For forecasting the capacity prices, the historical capacity prices was used for the "Rest of State" region that applies to Zone C for years when no capacity additions were required. The historical prices for capacity in the Zone C were ~$25,000 / MW-Year. "Rest of State" is currently considered to be all Zones except for Zone J (New York City) and Zone K (Long Island). The NYISO Capacity Demand Curve Study, which sets the cost of new entry in the "Rest of State" establishes an administrative cost of capacity at the 100% requirement including the Installed Reserve Margin at $7.5/kW-month or ~$90,000 /MW-year. This represents the revenue that would be required for new peaking unit to meet the Capability Period Peak Capacity Requirements.

Since the capacity addition module of the economic dispatch model only adds new capacity when the reserve margins would fall under 15%, it was assumed that for such years the capacity prices be at level of $90,000 / MW-Year in 2009 real $. For future years, when there was no capacity addition is required, it was assumed the capacity prices will remain on an average to the levels observed in "Rest of the State" during the period from 2005-10 of $25,000 / MW-Year (in 2009 Real $). The same GDP index applied to the fuel prices is used to escalate the capacity prices for future years.

Figure below shows the results of the capacity price projections for the duration of the proposed CAES project. The jump in the capacity prices correspond to the years when the model projects need for new capacity addition in NY.

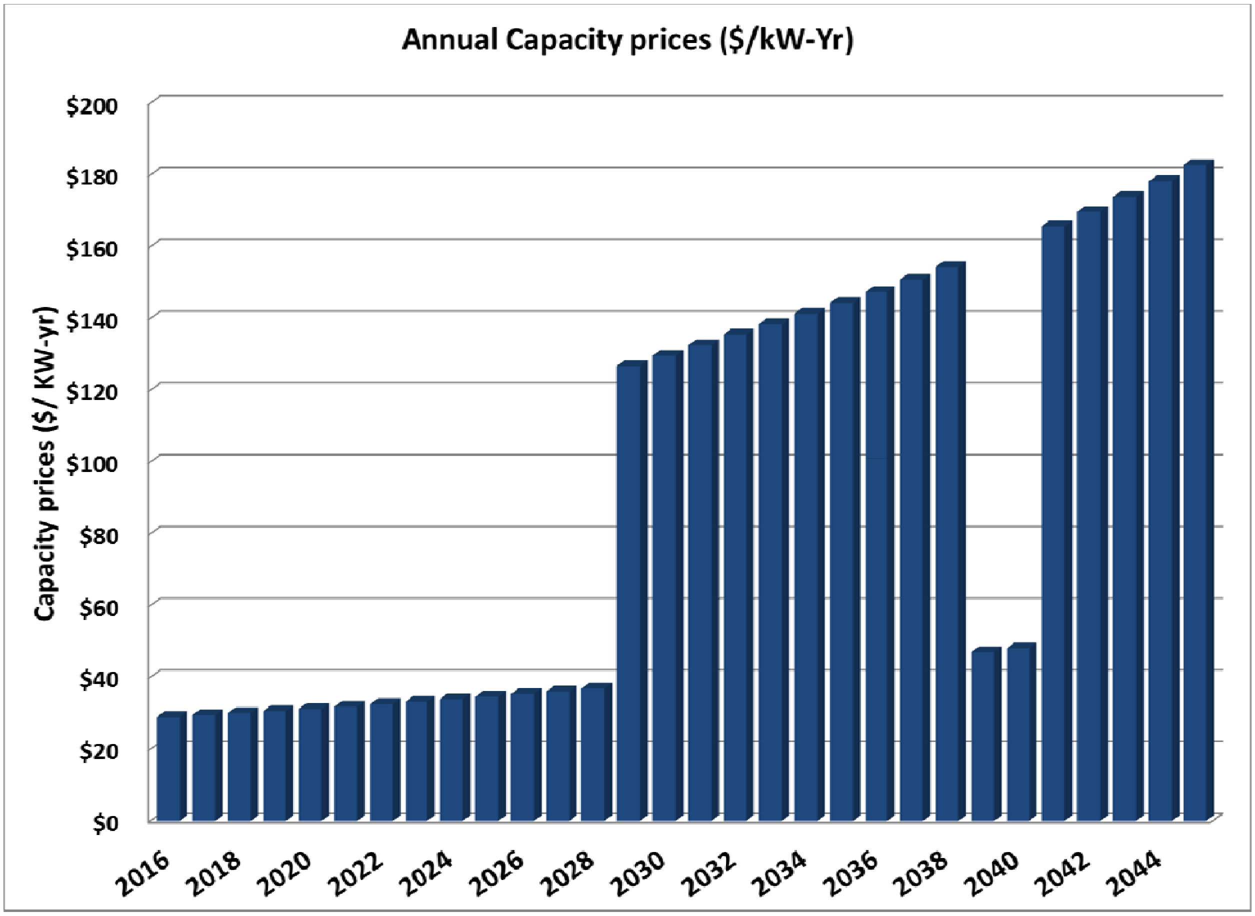

Figure 13: Capacity price forecast for Rest of the State Region of NYISO

3.6 Market Price Scenarios

NYISO markets are currently dealing with number of issues that will influence the proposed CAES plant economics during the course of the planned 30 year operating life (2016-2045). These issues include potential changes in the supply mix due to various environmental rule changes, potential retirement of coal and nuclear plants, merchant plant additions, and significant addition to renewable generation, particularly wind.

To assess the sensitivity of the analysis, the CAES Dispatch Model includes scenario analysis capability to understand the impact of the following scenarios on the operation and resulting net revenue expectations of the facility. The additional market scenarios are based on the scenarios identified in the NYISO Congestion Assessment and Reliability Study

(CARIS) and vetted through the NYISO Stakeholder process. The scenarios included relate directly to the operation of the CAES facility in Zone C and are listed below:

3.6.1 Base Case

The load forecast used in the CAES base case was taken directly from the 2011 NYISO Load & Capacity Data Report, referred to as the Gold Book. The 2011 Gold Book forecast for peak load reflects an annual average growth rate of 0.73% for years 2011 through 2021. The 2011 growth rate is lower than the 2010 growth rate due to a lower econometric forecast and an increase in the projected amounts of energy savings from the Energy Efficiency Portfolio program. The base case includes a 0.8% peak load growth rate from 2021 through the study horizon.

The chart below shows the anticipated load growth over the decision horizon used in the base case vs. the RNA 15*15 scenario.

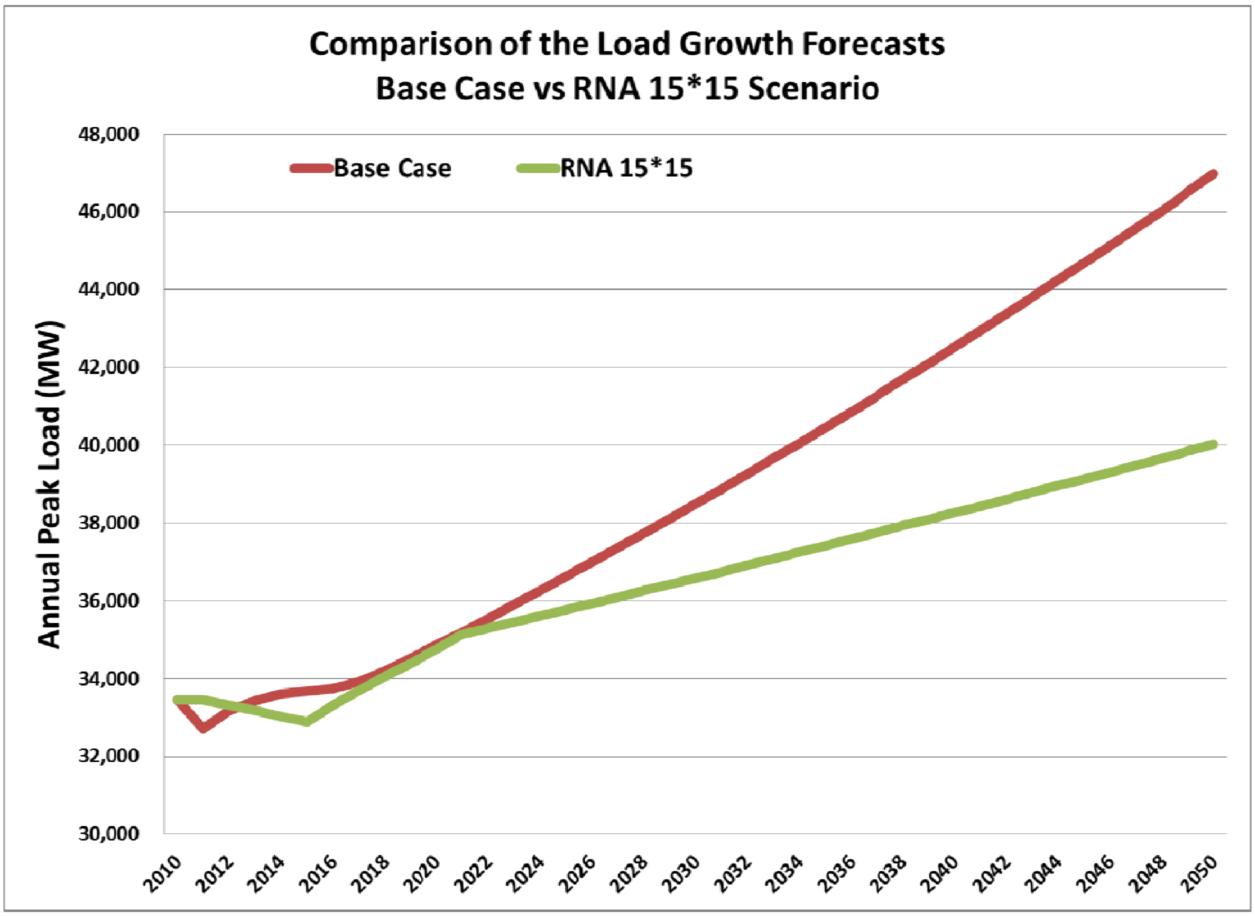

Figure 14: Anticipated load growth under base case scenario vs. the RNA 15*15 scenario

The starting point for the fuel forecast used in the CAES base case came from the 2010 U.S. Energy Information Administration (EIA) long term forecast of delivered fuel prices. The natural gas price forecast included in the CAES base case reflects 105% of the forecast Henry Hub prices to account for delivery to New York with an additional 5.5% added to account for delivery to NYISO Zone C according to the methodology used for NYISO CARIS studies. We have also adjusted the US Energy Information Administration's (EIA), Annual Energy Outlook (AEO) forecasts from the Real 2009 dollars to the nominal dollars for the corresponding year with the Gross Domestic Product (GDP) index from the AEO forecast. This is consistent with the methodology used by NYISO for CARIS studies. Seasonal variations were then applied to the annual average fuel price to get the month by month variations using the seasonal variation data used by NYISO for CARIS studies.

As explained later, we used natural gas prices of one standard deviation above and below the base case for generating the natural gas forecasts for the low gas and high gas scenario. Following figure shows the three natural gas price forecasts used in this analysis.

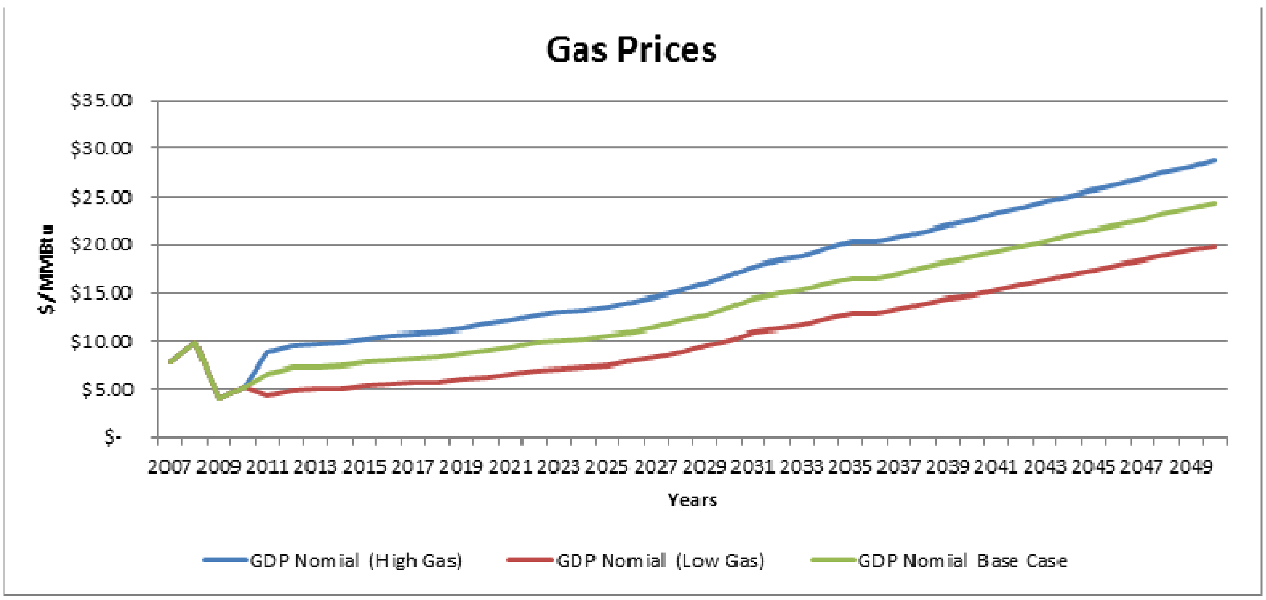

Figure15: Forecasted average natural gas prices for each year using AEO 2010 forecast adjusted for upstate NY in nominal $

Environmental mandates and emissions costs were developed from preliminary NYISO data from the 2011 CARIS process. CO_2 Regional Greenhouse Gas Initiative (RGGI) emission allowances are forecast to remain at the offer floor until 2013 when a reset by the RGGI States places upward pressure on prices with allowances reaching $10/ton in 2015. RGGI allowance prices are forecast to increase 2.5% annually thereafter. The EPA's Cross-State Air Pollution Rule (CSAPR) goes into effect 1/1/2012 regulating SO_2 and NO_x. The EPA provided an estimate of allowance costs:

	Emission Allowance Prices	(2007$/Ton)
	2012	2014 forward
Annual SO2	$1000	$1100
Annual NOx	$500	$600
Ozone Season NOx	$1300	$1500

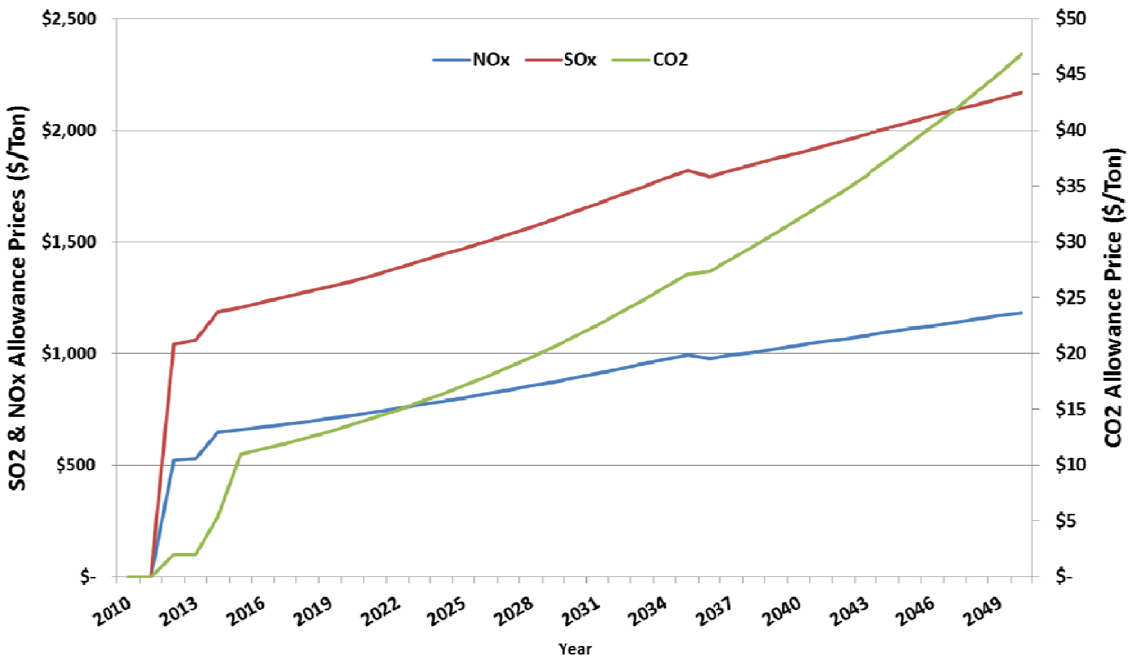

Figure 16**: Emission allowance price assumptions used under base case**

The CAES base case assumes that all coal fired generation located in Upstate New York will be retired by 2015 and that all nuclear generation is retired sixty years after the original licensing date. The base case also assumes that projects in the NYISO Interconnection Queue that have accepted their cost allocation in the Class Year process and have an interconnection agreement in process will be on-line by their projected in-service dates. The following renewable projects are included in the supply stack coming on-line by 2015.

Queue			Date	SP	WP	Type/	Location		Interconnection			Last	Availabilit	Proposed In-Service	
Pos.	Owner/De	Project Name	of IR	(MW)	(MW)	Fuel	ounty/Stat	Z	Point	Utility	S	Update	of Studies	Original	Current
119	ECOGEN,	Prattsburgh Wir	5/20/02	78.2		W	Yates, NY	C	Eelpot Rd-Flat St. 1	NYSEG	10	9/30/10	SRIS, FS	2005/02	2012/05
147	NY Windp	West Hill Windf	4/16/04	31.5		W	Madison, N	C	Oneida-Fenner 115I	NM-NG	10	9/30/10	SRIS, FS	2006/Q4	2012/09
161	Marble Riv	Marble River Wi	12/7/04	84	84	W	Clinton, NY	D	Willis-Plattsburgh V	NYPA	11	7/31/11	SRIS, FS	2006	2012/10
166	St. Lawren	St. Lawrence W	2/8/05	79.5	79.5	W	Jefferson,	E	Lyme Substation 1:	NM-NG	10	6/30/11	SRIS, FS	2006/12	2013/09
171	Marble Riv	Marble River II V	2/8/05	132.3	132.3	W	Clinton, NY	D	Willis-Plattsburgh V	NYPA	11	7/31/11	SRIS, FS	2007/12	2012/10
182	Howard W	Howard Wind	3/21/05	57.4	57.4	W	Steuben, N	C	Bennett-Bath 115k\	NYSEG	12	6/30/11	ES, SRIS, F	2007/10	2011/12
186	Jordanville	Jordanville Winc	4/1/05	80	80	W	Herkimer,	E	Porter-Rotterdam 2:	NM-NG	11	6/30/10	SRIS, FS	2006/12	2011/12
197	PPM Roar	Roaring Brook \	7/1/05	78	78	W	Lewis, NY	E	Boonville-Lowville 1:	NM-NG	11	3/31/11	ES, SRIS, F	2009/12	2012/12
207	Cape Vinc	Cape Vincent	1/12/06	210	210	W	Jefferson,	E	Rockledge Substati	NM-NG	10	6/30/11	ES, SRIS, F	2009/Q4	2013/09
213	Noble Envi	Ellenburg II Win	4/3/06	21	21	W	Clinton, NY	D	Willis-Plattsburgh V	NYPA	10	6/4/10	SRIS, FS	2007/10	2011/10
		CY 2009													
222	Noble Ball	Ball Hill Windpa	7/21/06	90	90	W	Chautauqu	A	Dunkirk-Gardenville	NM-NG	9	2/16/10	FES, SRIS	2008/10	2011/12
		CY 2010													
237	Allegany V	Allegany Wind	1/9/07	72.5	72.5	W	Cattaraugu	A	Homer Hill – Dugan	NM-NG	9	6/30/10	FES, SRIS	2009/10	2011/10
254	Ripley-We	Ripley-Westfielc	8/14/07	124.2	124.2	W	Chautauqu	A	Ripley - Dunkirk 23(	NM-NG	9	6/30/10	FES, SRIS	2007/12	2011/12
263	Stony Cree	Stony Creek W	10/12/07	88.5	88.5	W	Wyoming,	C	Stolle Rd - Meyer 2	NYSEG	9	2/28/11	FES, SRIS	2010/01	2012/12
330	Long Islan	Upton Solar Far	4/7/09	31.5	32	S	Suffolk, NY	K	8ER Substation 69I	LIPA	9, 12	12/31/10	SRIS	2011/05	2011/05
		other non-class gens													
180A	Green Pov	Cody Rd	3/17/05	10	10	W	Madison, N	C	Fenner - Cortland 1	NM-NG	11	3/31/11	None	None	2011/Q4
204A	Duer's Pat	Beekmantown \	10/31/05	19.5	19.5	W	Clinton, NY	D	Kents Falls - Sciota	NYSEG	10	4/30/11	None	2008/06	2013/06

The following figures show the generation retirements by fuel type, generation additions by fuel type and the resultant generation mix by fuel type over the decision horizon.

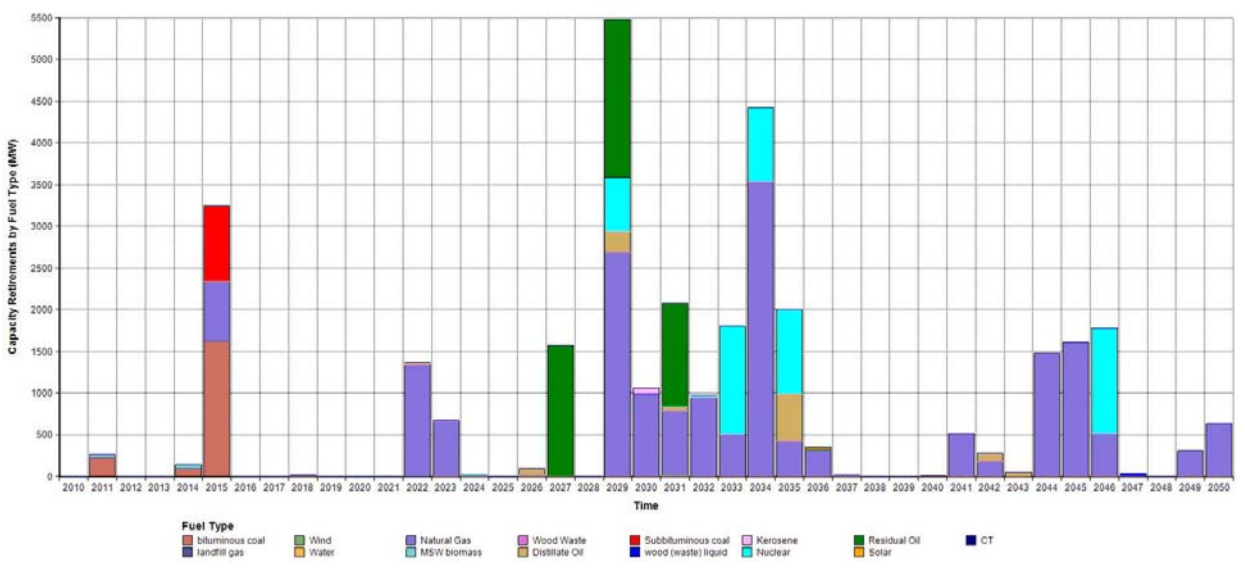

Figure17**: Anticipated Generation Retirements under Base Case Scenario**

In the Supply queue, the NYISO Gold Book was used for the historic supply fleet and the current supply base with additions of generation as noted in the September 2011 Interconnection queue. Beyond 2018 (the date for the last projects identified in the queue), the model attempts to predict the generation additions using the logic that non-wind generation will be added in the supply mix only when the reserve margin requirements dictate the addition. Thus, generation is assumed to get added as total installed capacity based on the load growth approaches a 15% Reserve Margin. At this capacity need point, new generation blocks of 500 MW combined cycle plants and 200 MW combustion turbines were introduced into the system in a ratio of (70:30). This ratio is based on historical average generation additions in Mid-Atlantic region. After 2018, wind will be added to the supply fleet at a rate of 200 MW per year. Wind is anticipated to be economical with the subsidies and will continue to get added irrespective of the reserve margin requirements. The main reason for capping the wind additions at 200 MW / year was based on anticipated challenges for interconnection and transmission availability.

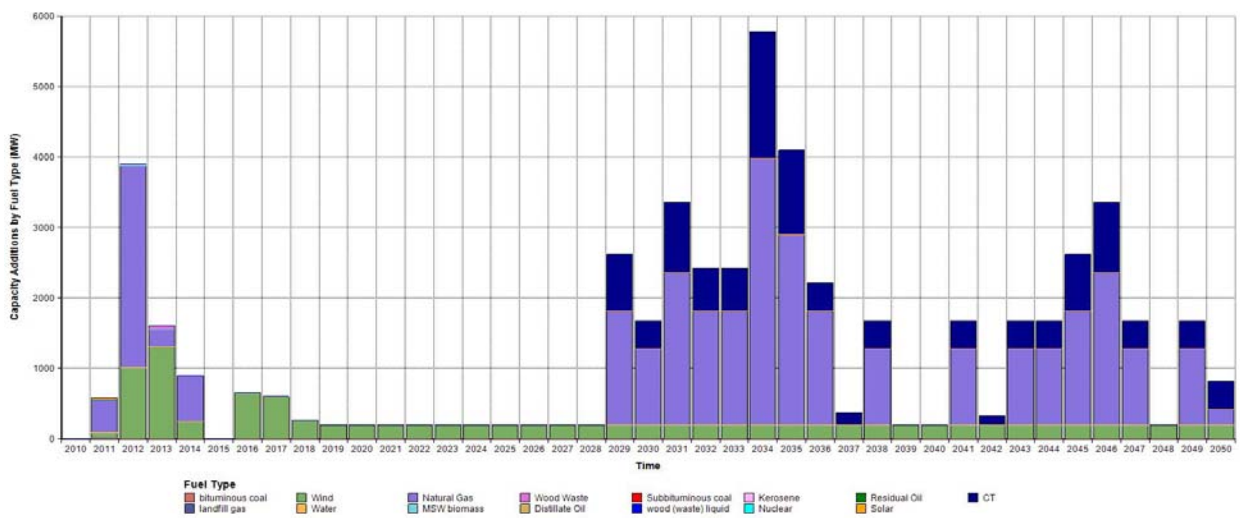

Figure 18: Anticipated capacity additions under base case scenario

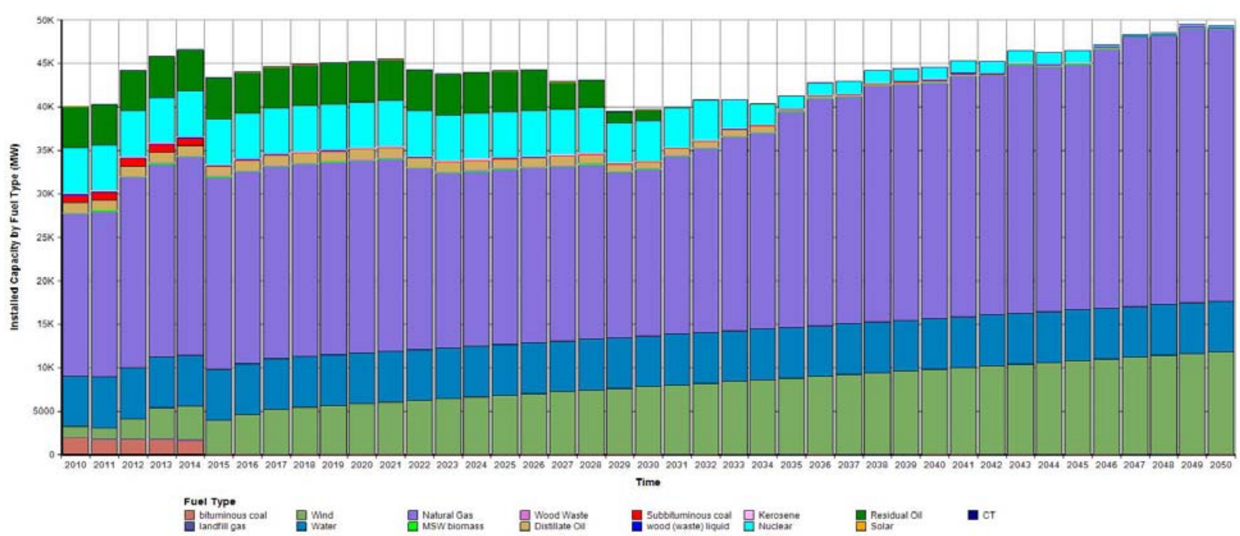

Figure19**: Anticipated capacity mix by fuel type under base case scenario**

3.6.2 Indian Point Retirement Scenario

The NRC licenses for Indian Point 2 and 3 expire in 2013 and 2015, respectively. This scenario assumes that both units are retired by 2016 and therefore the CAES evaluation does not include them in the supply mix. This has impact on both the energy prices throughout the State and the accelerated capacity additions required for maintaining the 15% reserve margin required under NERC criteria.

Charts below show the generation retirements forecasted for this scenario. Please note the two large retirements in light blue in 2013 and 15 representing the Indian Point Nuclear Units.

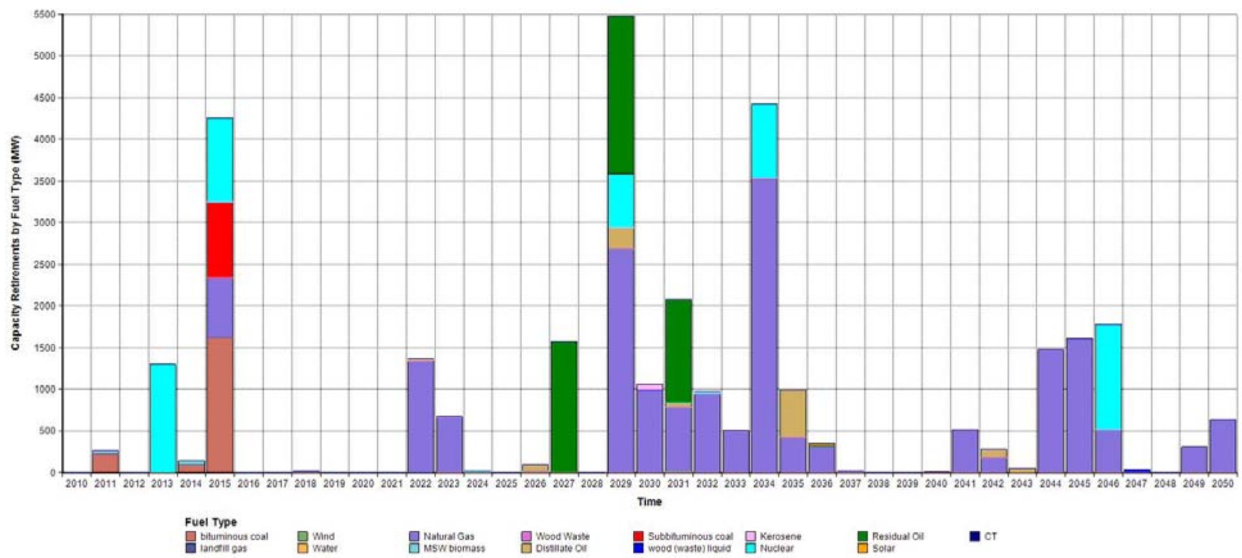

Figure 20: Anticipated generation retirements under the Indian Point Retirement Scenario

The Indian Point retirement results in higher capacity additions in 2029 as compared to the base case scenario to maintain the same reserve margin considering the retirement of the 2 nuclear facilities which under base case scenarios would have been operational in 2029.

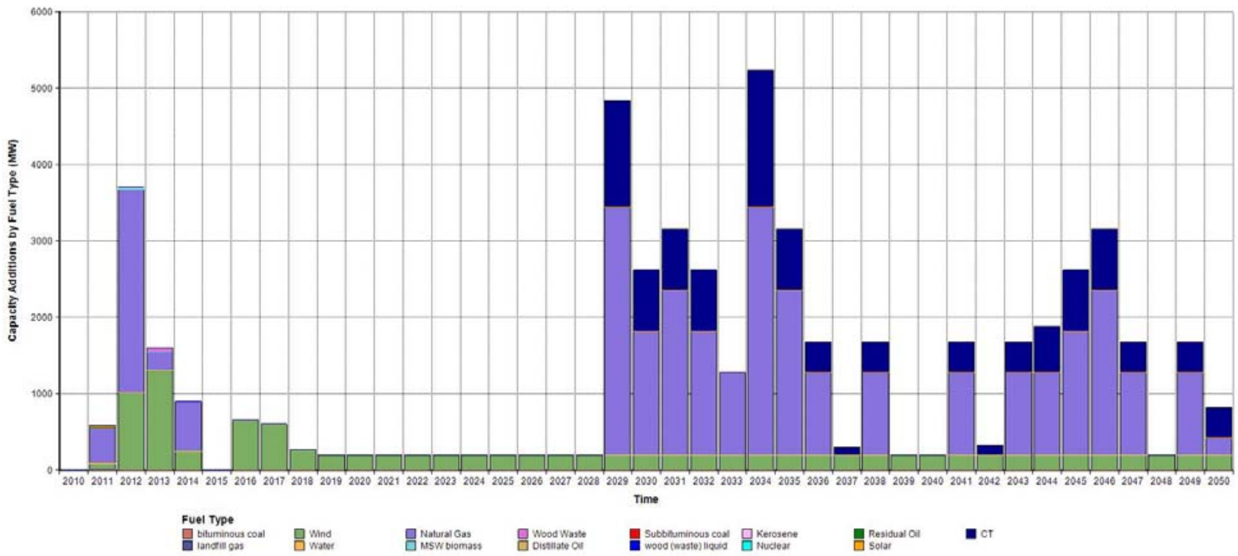

Figure 3: Anticipated generation additions under the Indian Point Retirement Scenario

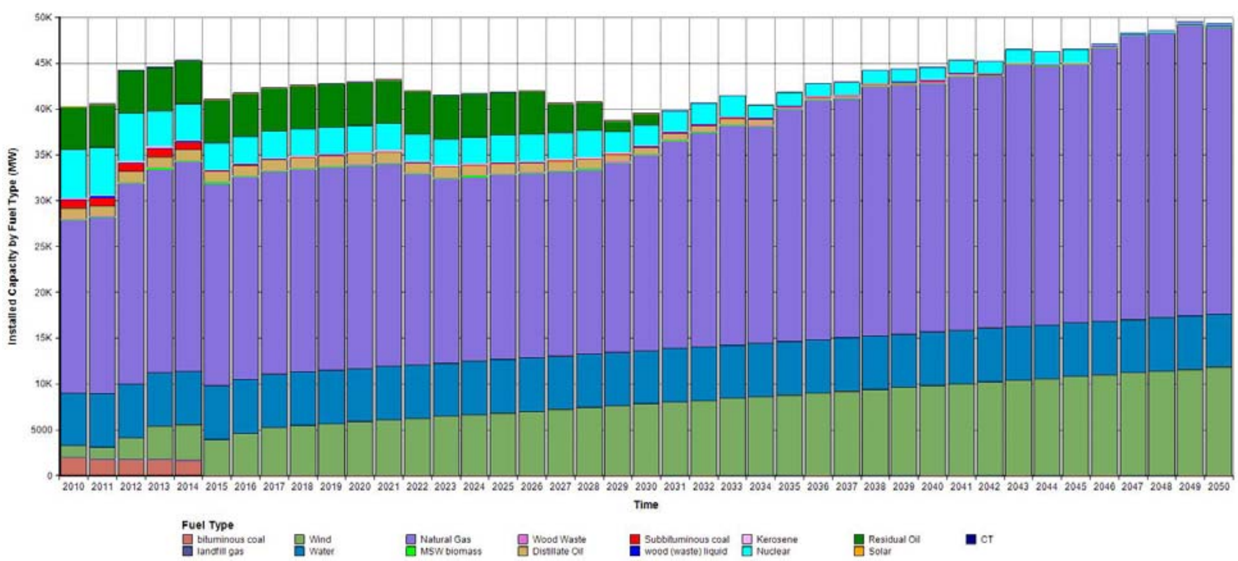

Figure 4: Anticipated generation mix by fuel type under the Indian Point Retirement scenario

3.6.3 Electric Energy Portfolio Standard (EEPS) Achieved and Low Load Growth Scenario

The Electric Energy Portfolio Standard (EEPS) scenario models New York's policy goals to serve 30% of the state's energy needs with renewable resources and reduce energy usage by 15% both by the year 2015 This program is commonly referred to as the 45x15. As reflected in the NYISO's 2010 RNA, in this scenario peak load forecast in MWs through 2020 are:

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
32,945	32,805	32,662	32,521	32,377	32,794	33,172	33,529	33,866	34,227

The projected average load growth of 0.45% beyond 2021 was used to forecast the loads though 2045. This results in approximately 4000 MWs of lower peak load of 40 GWs in 2050 as compared to the base case scenario. Following figure shows the anticipated peak load.

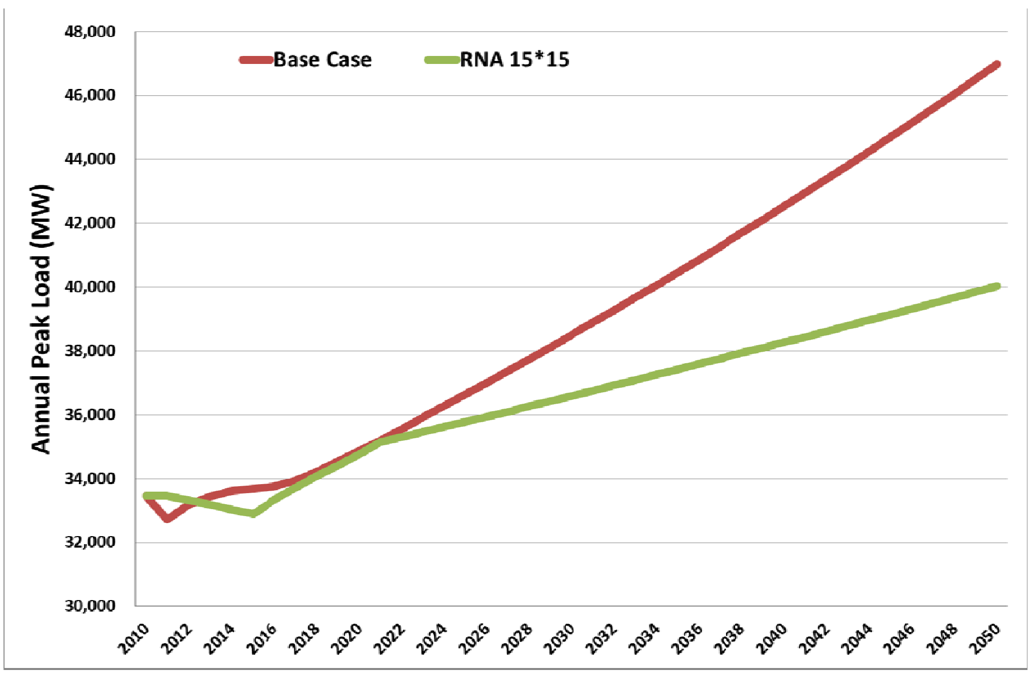

Figure 52: Comparison of the load projections for base case vs. the RNA 15*15 scenario

High Natural Gas Price Scenario

The high natural gas price scenario will reflect gas prices that are one standard deviation ($2.22/mmbtu) above the natural gas prices used for base case scenario. based on the fuel forecast used in the CAES base case from the 2010 U.S. Energy Information Administration (EIA) long term forecast of delivered fuel prices. The natural gas price forecast included in the CAES high natural gas reflects 105% of the forecast Henry Hub prices to account for delivery to New York with an additional 5.5% added to account for delivery to NYISO Zone C. The anticipated natural gas prices are shown in Figure15 for the LBMP modeling we applied the seasonal adjustments to come up with the monthly fuel prices using same methodology described in base case.

3.6.4 Low Natural Gas Price Scenario

The low natural gas price scenario will reflect gas prices that are one standard deviation below mean ($2.22) based on the fuel forecast used in the CAES base case came from the 2010 U.S. Energy Information Administration (EIA) long term forecast of delivered fuel prices. The natural gas price forecast included in the CAES low natural gas price case reflects 105% of the forecast Henry Hub prices to account for delivery to New York with an additional 5.5% added to account for delivery to NYISO Zone C. The anticipated natural gas prices are shown in Figure15.

3.6.5 High Wind Scenario

For the LBMP modeling we applied the seasonal adjustments to come up with the monthly fuel prices using same methodology described in base case.

The High Wind scenario assumes that the wind projects currently under the NYISO interconnection queue will be built and wind generation will continue to be added at a rate of 200 MWs / year rate until the wind capacity maximum reaches a level of 12 GW in New York, which is assumed as the maximum amount of wind that can be installed in New York.

The following chart shows the anticipated generation additions and resultant installed capacity by fuel type under this scenario. Under this scenario, the wind penetration reaches the 12 GW cap in 2048. Since the anticipated CAES facility life is 30 years (2016-2045), this assumption has no impact on the project evaluation.

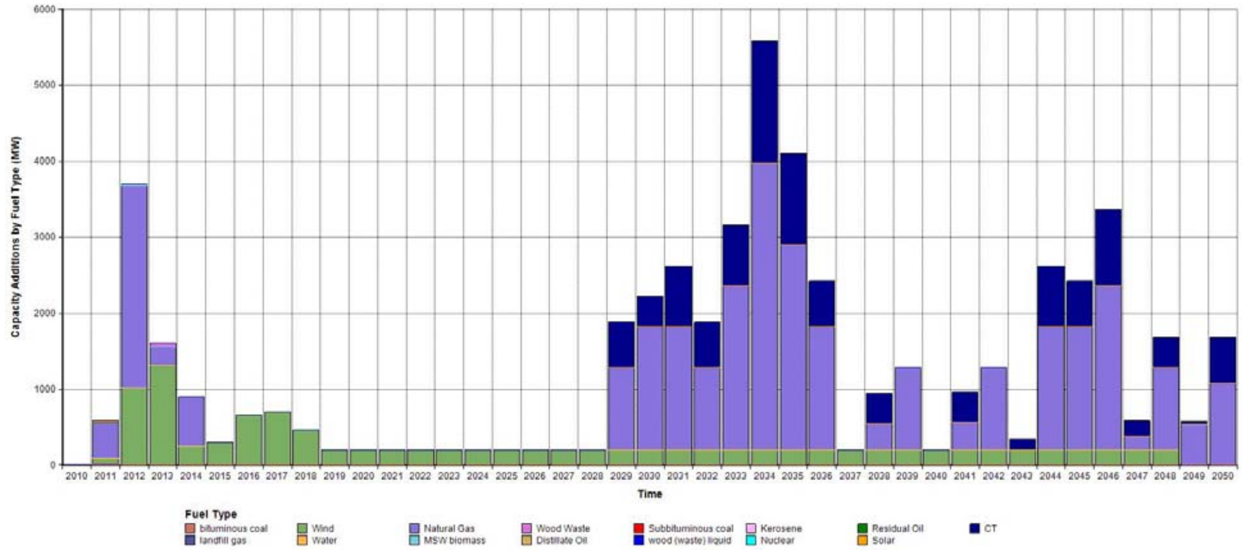

Figure 23: Anticipated capacity additions under High Wind scenario

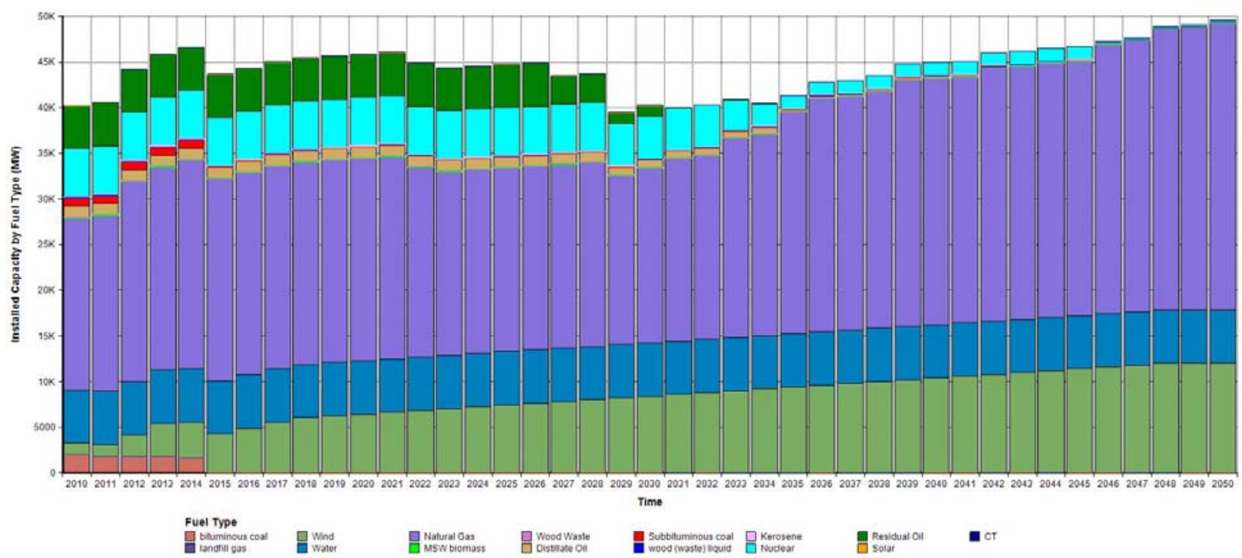

Figure 24: Installed capacity in NYISO under High Wind Scenario

The figure below shows the difference in the projected average LBMPs till 2045 under different scenarios.

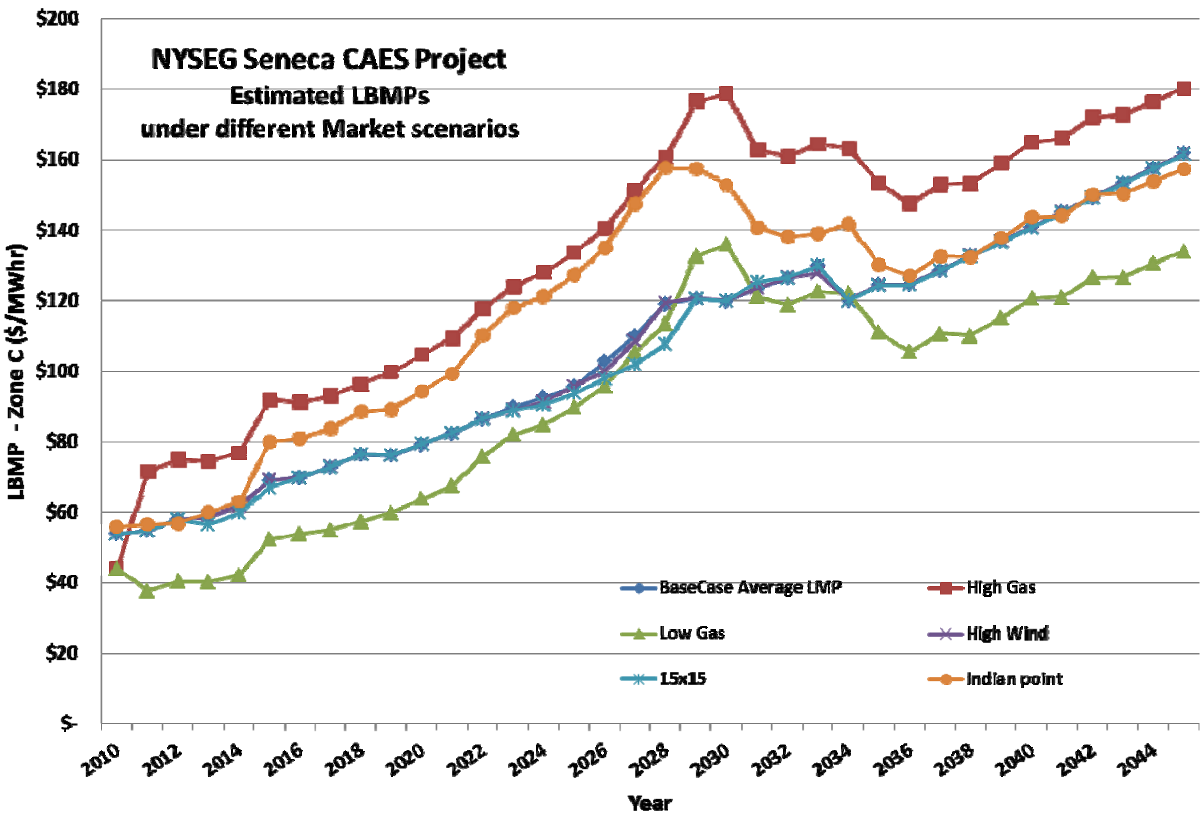

Figure 6: Projected average LBMPs under different scenarios

Figure below shows the projected capacity prices under 2 scenarios where there is a difference in the capacity additions from year to year. These are base case and the Indian Point Retirement Scenario.

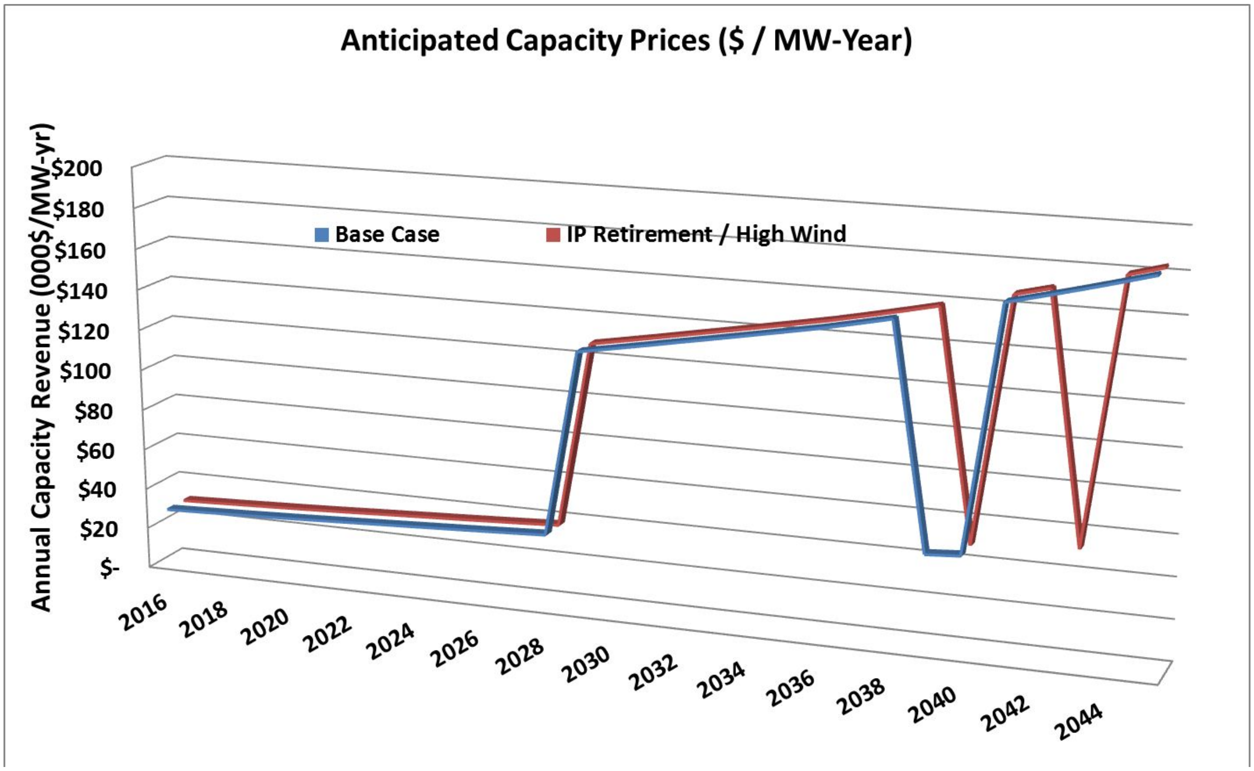

Figure 7: Capacity price forecast under base case and Indian Point Retirement scenario

4 Dispatch Modeling

4.1 Background

There are two CAES plants currently operating in the world. The McIntosh CAES plant in Alabama was designed to store as compressor air the lower cost excess coal power that is available in the off peak periods and then release the stored energy in the compressed air to generate electricity during the higher cost energy periods during the peak periods of the day. The Huntorf CAES plant in Germany is mainly used for peak shaving and operating reserve.

For the NYSEG Seneca CAES Project, the charging of the compressed air storage area, in this case the salt cavern, is accomplished in the off peak periods of the weekday and over the weekend periods when energy prices are low. This mode of operation help supports the electric system where the off peak loads may not be large enough to maintain the supply fleet operational for the following day's peak load requirements. This is especially important in systems that have a considerable amount of nuclear or other types of generation that can only be backed down to a certain level of operation or need to taken off line.