Outlook for the New York wholesale power market and analysis of the drivers of transmission congestion within the New York Markets

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Prepared for

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by

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1 Executive Summary

Key findings

Several factors will combine to significantly reduce congestion in the energy market between western and eastern NY over the next 20 years:

- The decline in locational natural gas price difference between western and eastern NY
- Gradual retirements of baseload generation in western NY together with the entry of new CCGT resources in eastern NY
- NYISO's flat energy demand forecast for the state over the next 10 years

London Economics International LLC ("LEI") has been engaged by the Hudson Valley Smart Energy Coalition ("HVSEC") to assist in the New York Public Service Commission ("NY PSC") Case 13-E-0488 *In the Matter of Alternating Current Transmission Upgrades Comparative Proceeding*. This NY PSC proceeding has been established to evaluate proposed AC transmission line upgrades that would increase internal transmission interface limits between the western regions of the state and the Lower Hudson Valley ("LHV"). Several transmission project proposals by four developers are currently being evaluated by the NY PSC in this proceeding. The idea for such transmission projects originated following the Governors' Energy Highway initiative, where it was proposed that new transmission be built to relieve congestion costs in the LHV and thereby reduce the cost of electricity (energy and capacity) for eastern NY residents. In the context of relieving congestion, LEI was asked by the HVSEC to provide its own independent outlook for the New York wholesale power market for the longer term and the potential level of congestion costs that could be expected between western and eastern New York.[1]

1.1 Scope of analysis

LEI prepared a forward-looking market study of the energy and capacity prices based on its current base case outlook over the 2016-2034 horizon for the New York wholesale electricity market, preparing results based on three separate natural gas pricing scenarios. With these different outlooks for energy and capacity prices in New York, LEI then assessed the magnitude of congestion in the energy markets over the Central-East ("C/E") interface, which separates western (zones A through E) and eastern NY (zones F through K), and the UPNY/SENY interface which limits flows into the LHV under certain circumstances. LEI also examined the

[1] London Economics International is a global economic, financial and strategic advisory professional services firm specializing in energy, water and infrastructure. LEI's principals have testified before the NY PSC on issues related to the benefits of new transmission infrastructure, as well as the tradeoffs between generation and transmission. LEI's market analysis has also supported power plant investment and financings. Please refer to Appendix A for LEI's qualifications and experience in the New York markets.

capacity market-related congestion based on capacity price differences that arise between the NYCA zone and LHV zone (also known as New Capacity Zone or "NCZ").

LEI was not engaged to directly assess or otherwise evaluate the potential impacts of any of the proposed AC transmission projects under review by the NY PSC in Case 13-E-048. LEI's outlook for the NYISO wholesale electricity markets employs the current transmission topology[2] (albeit integrating transmission solutions previously accepted by the NY PSC such as the Transmission Owners Transmission Solution ("TOTS")). Therefore, LEI cannot calculate any benefit to consumers or production cost savings value that could result from the proposed transmission projects.

1.2 Summary of projected market trends

LEI's base case outlook for energy and capacity prices over the 2016 to 2034 horizon assumes normal conditions in terms of weather, demand and operations of generation. LEI relies on NYISO's 2015 Load and Capacity Report ("Gold Book") for the energy and peak load forecast as well as details regarding the capacity and location of existing generators within the New York Control Area ("NYCA"). LEI further introduces additional new generation if and when it is economically feasible given the simulated market dynamics.

Because of the large percentage of generators within the NYCA that rely on natural gas as their fuel, the price of natural gas has a strong impact on electricity price levels and the market value of transmission congestion. However, there is a lot of uncertainty in how natural gas prices will evolve in the future. For this reason, LEI elected to model three different natural gas price scenarios.

LEI's first natural gas scenario (*Marcellus Shale gas with pipeline expansion)* assumes that the price differential between western and eastern NY natural gas prices remains low over the forecast horizon as new pipeline capacity continues to be built to take away low cost Marcellus shale gas supply from the Mid-Atlantic region and bring it into New York and the New England region. Therefore, this scenario assumes that the long-term trend in prices for natural gas across the NYCA is linked to the price of supply from the Marcellus Shale region, rather than conventional gas supply from the Gulf region.

The second natural gas scenario (*Henry Hub gas with pipeline expansion)* assumes that the marginal supply of gas in NYCA is linked to supplies originating from the Gulf region (based on the price of gas at the Henry Hub ("HH") as forecast in EIA's Annual Energy Outlook); conventional gas supply is more expensive than Marcellus Shale supply under normal operating ranges. In this scenario, LEI used forward prices for the first three years and a Levelized Cost of Pipeline ("LCOP") model for the longer term forecast. In LCOP, gas price spread between two pricing hubs is assumed not to exceed the levelized cost of building a new

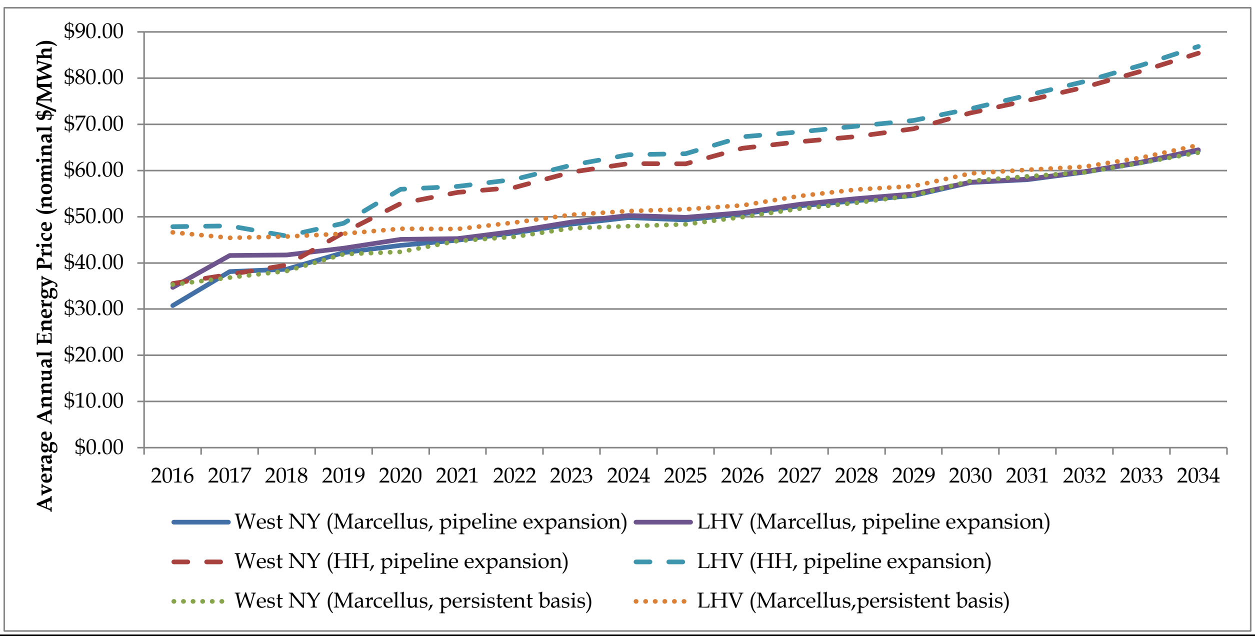
[2] LEI's study does not assume any new transmission capability built in NY or retired over the forecast horizon with the exception of the TOTS project

pipeline between the two hubs. This levelized cost therefore effectively sets a long-term price cap on the transportation cost or basis differential between two pricing hubs. As a result, this scenario also assumes a build-out of new pipeline capacity in the Northeast United States, which will reduce the basis differential between natural gas prices in eastern and western NY.

The final natural gas scenario (*Marcellus Shale gas with persistent basis differential)* assumes that natural gas prices in eastern NY will trade at a premium to western NY, similar to what has been observed historically, even under normal conditions. In this scenario, LEI assumes that the marginal source of supply originates from the Marcellus Shale region, resulting in price levels which are lower than in the Henry Hub gas scenario above. However, because of more limited pipeline build-out in the Northeast, there is a persistent differential in gas prices which gradually declines from $0.90/MMBtu to $0.30/MMBtu over the modeling time horizon.

Energy prices as modeled under LEI's outlook are highest under the *Henry Hub gas with pipeline expansion* scenario given the overall gas price levels as compared to the *Marcellus Shale gas with pipeline expansion* scenario. Furthermore, energy price levels over time under the *Marcellus Shale gas with persistent basis differential* scenario converge to the *Marcellus Shale gas with pipeline expansion* scenario. Figure 1 illustrates the resulting energy prices for the West NY[3] (NYISO zones A through E) and LHV (NYISO zones G, H and I) zones under all 3 natural gas price scenarios.

Figure 1. Forecasted annual energy market prices in the West NY and LHV zones



[3] POOLMod's West NY zone, encompassing NYISO zones A through E, corresponds to the more generic western NY region

The *Henry Hub gas with pipeline expansion* results in the highest prices overall because the long term forecast for Henry Hub prices is much higher than the price for natural gas in the Marcellus Shale region. Furthermore, energy price separation between West NY and the LHV zones in LEI's projections is reduced over time as the basis differential between natural gas prices in eastern versus western NY declines and also as a result of new generation coming online in the LHV, New York City ("NYC") and Long Island ("LI").

The *Marcellus Shale gas with pipeline expansion* and *Marcellus Shale gas with persistent basis differential* scenarios both exhibit similar pricing levels and trends over time. However, while prices between West NY and the LHV converge in the former scenario over the forecast horizon, price separation is present in the latter scenario, but even then it declines over time in line with the difference between natural gas prices in western versus eastern NY.

Under the *Henry Hub gas with pipeline expansion* scenario, the gas price outlook through 2018 is similar to current forward prices and as such the resulting energy prices are consistent with forward energy prices for western versus eastern NY. Furthermore, historical and forward implied market heat rates allow for a comparison of price trends by normalizing for gas price levels. LEI's forecast is aligned with actual and near-term forward market heat rates, which confirms the congruency of the forecast to known market trends. Finally, LEI's forecast is dynamic in the sense that new entry and retirements reflect projected market dynamics over time. For these reasons, LEI's forecast can be relied upon as an accurate representation of future market conditions under the set of assumptions used to produce the forecast.

LEI modeled distinct capacity outlooks to accompany the three varying energy market outlooks (due to different gas price assumptions)[4]. The resulting forecasted capacity market prices are only marginally different between the three scenarios. Capacity market prices are a function of supply relative to the demand curve. The demand curve is re-set every three years, and as part of the process, NYISO and its consultants will evaluate future energy market conditions to set the reference price for the demand curve. However, the difference in the value of the reference price between the various natural gas pricing scenarios is not sufficient to significantly affect the capacity price forecast.

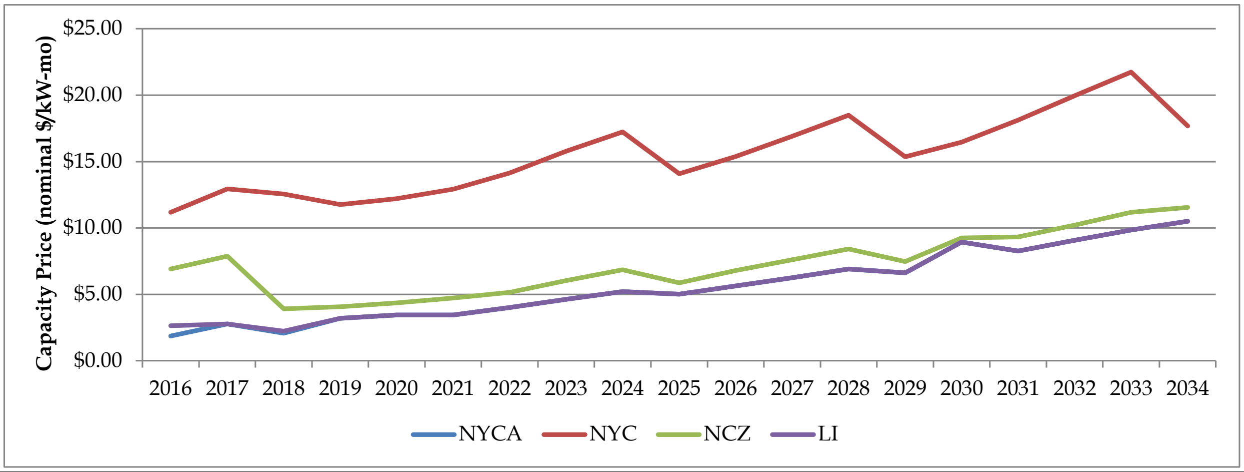
Figure 2 illustrates the capacity prices for the *Marcellus Shale gas with pipeline expansion* scenario, as capacity prices from all natural gas scenarios are nearly identical. Over the forecasting horizon, NYC prices generally remain much higher than other regions because of the higher reference point and relative difficulty of siting new generation in that part of the NYCA (for example, Buyer Side Mitigation ("BSM") rules prevent new entry from depressing capacity prices below a certain threshold and therefore limit when and how much new capacity is added in that locality). NYCA and LI capacity prices are forecasted to remain low initially then rise steadily as load growth increases the capacity requirement and the same supply intersects

[4] The level of energy prices influences the revenues earned by new generators in the energy market, which in turn influences the net CONE and the Reference Point used as a parameter for the capacity market spot auction Demand Curve (see detailed discussion in section 9.10)

higher up on the demand curve, which in turn bring market prices closer to the Cost of New Entry ("CONE"). Prices then rise sharply in later years following generator retirements. NCZ prices are initially much higher than NYCA and LI prices, but new entry within the locality in 2018 greatly reduces the price spread between these regions.

Figure 2. Forecasted capacity prices

Marcellus Shale gas with pipeline expansion scenario



1.3 Observations on projected congestion within the NYCA

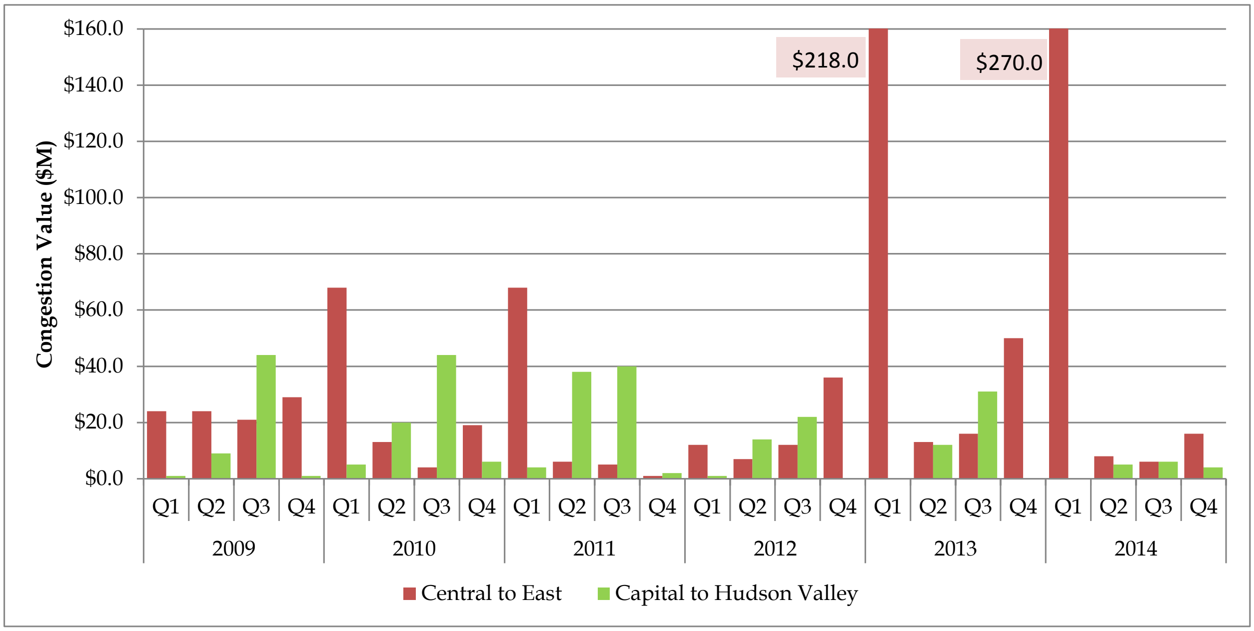
In New York, energy flows from West to East and from North to South towards the largest load zones which are NYC (zone J) and LI (zone K). The C/E interface is typically used as a boundary when referring to western NY and eastern NY. The UPNY/SENY interface separates the Mohawk Valley (zones E) and Capital (zone F) regions from the Lower Hudson Valley ("LHV" - zones G, H and I) region. These two interfaces are the focus of this report.

Historically, congestion in the energy market along the C/E interface has followed a seasonal pattern. Most of the congestion has been observed during the winter months in the first quarter and to a lesser extent in the fourth quarter. This seasonality suggests that congestion on this interface is strongly correlated to the spread between western versus eastern NY natural gas prices. Historically, that spread has been largest during the winter period and is exacerbated during periods of extreme cold.

UPNY/SENY congestion also follows a seasonal pattern. However, where the C/E congestion occurs mostly during the winter period, UPNY/SENY is congested the most during periods of high demand in the summer months. This seasonality pattern suggests that congestion over this interface is correlated to the level of demand in the state or summer weather events that reduce transmission capacity into the LHV.

Figure 2 illustrates historical congestion on the C/E and UPNY/SENY interfaces by quarter. The total level of congestion value[5] on the C/E and UPNY/SENY interfaces has varied between $100 million and $180 million annually from 2009 to 2012, but increased to $315 million and $340 million for 2013 and 2014 respectively as a result of increased natural gas price differential between western NY and eastern NY for these years.

Figure 3. Historical C/E and UPNY/SENY congestion by quarters



LEI modeled three scenarios for gas prices as gas price levels and locational differences in gas price levels impact the level of congestion. Consistent with the energy prices discussed above, congestion on the C/E and UPNY/SENY interfaces in LEI's base case outlook for the next twenty years is forecast to decline over time. The most significant drivers of this trend are additional supply resources in the LHV, NYC and LI regions and the underlying natural gas price differences between western and eastern NY. Year by year congestion costs from LEI's three energy market outlooks are illustrated in Figure 4.

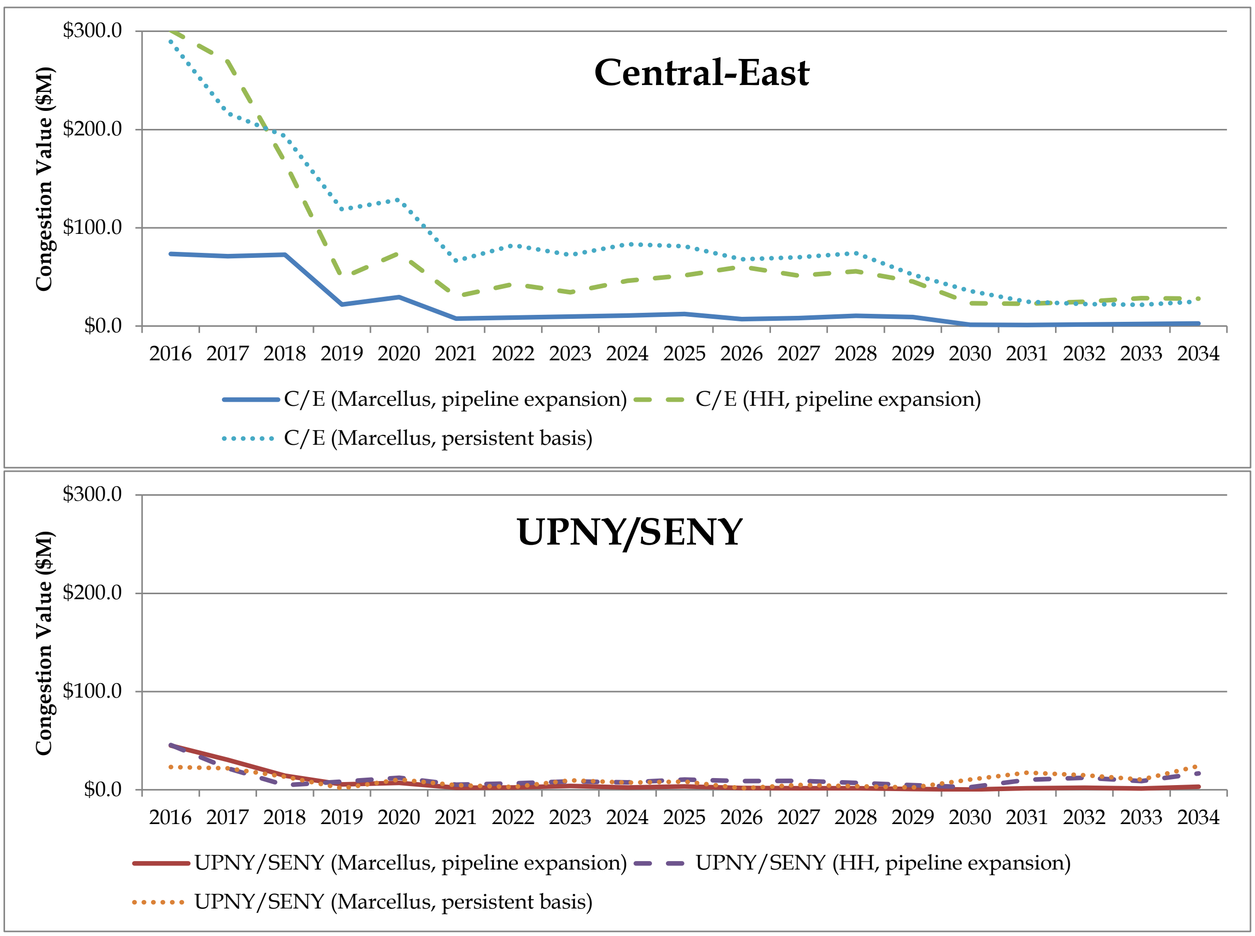
Congestion under the *Marcellus Shale gas with pipeline expansion* scenario is much lower than in the other two scenarios in early years as the natural gas price difference between eastern and western New York is much lower than in the other scenarios. The congestion level under this scenario is comparable to the congestion level observed in 2012 as the price level and locational differences in gas prices are also similar. Under the *Henry Hub gas with pipeline expansion* and *Marcellus Shale gas with persistent basis differential* scenarios, congestion costs start out at levels

[5] Congestion value is the sum, over all pricing intervals of a given period, of the difference in the congestion component of the LBMP between two zones multiplied by the energy flows between the two zones in that same given period.

similar to what has been observed historically in recent years and then decline in later years, as natural gas basis between western and eastern NY narrows and also due to new generation that comes online downstream of the constrained transmission interfaces (as detailed in appendix C, section 9.3).

Congestion in the capacity markets is reflected through the Locational Capacity Requirements, which represents the minimum amount of capacity which must be procured from generators located within that zone. As discussed previously, this minimum requirement for local capacity resources causes price separation between the different capacity zones and result in a higher cost of capacity for those consumers located in constrained zones. As shown in section 5.2, a hypothetical new transmission line that would have caused a reduction in the LCR of the NCZ by 500 MW for the 2015-2016 period would have resulted in savings to consumers of close to $140 million for the period. However, when considering transmission upgrades, the costs of such upgrades (which will factor into the transmission rates paid by consumers) must be weighed against the benefits (e.g., lower costs of capacity and energy, if applicable).

Figure 4. Forecasted C/E and UPNY/SENY congestion costs in the energy market



1.4 Qualitative consideration of drivers of congestion

The energy and capacity results presented above are representative of one set of assumptions for key drivers of market outcomes in the NYISO markets. LEI intentionally chose a combination of assumptions that would reasonably represent a base case outlook under normal operating conditions. LEI also assumed rational and effective investment, essentially "timed" to demand and modeled market conditions. However, in reality, the NYISO markets will not experience normal operating conditions year over year over the next twenty years. There is a high likelihood that there will be periods of unusual weather conditions. From practical experience, investment and retirement decisions will not be perfectly timed to market conditions. Furthermore, new technology developments and policy reforms may lead to other market developments that are not represented in LEI's base case outlook. In summary, there are a number of factors that can result in major drivers that influence congestion departing from the set of assumptions employed in the base case outlook. As such, there could be a different outcome for congestion within the NYCA than forecast in LEI's base case outlook.

As a general rule, increased demand, or increased natural gas prices (particularly an increase in price difference between different regions of the state), or generation retirements in eastern NY or new generation in western NY will increase energy market congestion over the C/E and UPNY/SENY interfaces. Conversely, lower demand compared to the forecast, or generation retirements in western NY, or new generation in eastern NY[6] or new AC transmission capacity (particularly on the interfaces at issue in this study) will decrease congestion over these interfaces. Figure 5 summarizes the major drivers of congestion by their directional impact. It was beyond the scope of this study to explicitly model all possible and plausible variations of these drivers. Nevertheless, in recognition of the impacts that these drivers can have on the modeled market outcomes and conclusions regarding congestion, LEI discusses these drivers qualitatively in Section 5.3.

[6] Including new direct current transmission projects bringing energy and capacity to the LHV, NYC or LI regions

Figure 5. Congestion drivers and their impact on NYCA congestion value

Congestion Driver	Increased Congestion	Decreased Congestion
Increased demand	↑	
Decreased demand		↓
Increased natural gas basis differential between western and eastern NY	↑	
Increased natural gas prices	↑	
Generation retirement in western NY		↓
Generation retirement in eastern NY	↑	
New Generation in western NY	↑	
New generationin eastern NY		↓
New Transmission capacity		↓

The likelihood of directional changes in drivers (for example, demand being lower versus demand being higher) is not always the same. The asymmetry arises in part because of the assumption that LEI has taken in the Base Case. As discussed previously, demand is an important driver of congestion. LEI relies on the NYISO 10 year load forecast. The 2015 forecast from NYISO integrates Energy Efficiency and Distributed Generation and results in a relatively flat energy profile over the next 10 years. However, should these programs prove less effective than anticipated by the NYISO, the resulting energy usage and peak load could be higher than forecast, resulting in congestion which is higher than predicted over the C/E and UPNY/SENY interfaces. Similarly, should summer temperatures prove warmer than average, the resulting increase in load could also lead to increased congestion as compared to LEI's base case forecast.

Another key congestion driver is the location of energy supply resources with respect to the transmission interfaces. Since most new entry in LEI's base case is located in the LHV, NYC or LI regions, delays in the commissioning of new supply resources would cause higher congestion values across the C/E and UPNY/SENY interfaces to continue longer than in LEI's base case outlook. Unforeseen retirements of resources in these regions would also have a similar effect on congestion. Conversely, it is unlikely that more resources than forecasted would come online in eastern New York, resulting in further decreases of congestion.

Finally, several unforeseeable events such as long-term outages of key transmission links, long-term outages of generators or weather-related events such as the number of Thunder Storm

Alerts ("TSAs") can affect congestion across the major NYISO transmission interfaces. Such events were not modeled in the LEI Base Case.

In summary, LEI's outlook is a reasonable forecast of congestion over the C/E and UPNY/SENY interfaces in the next 20 years under normal operating conditions. LEI examined how market prices and congestion would evolve under three different natural gas pricing scenarios. However, more extensive analysis of other drivers of congestion (as discussed above and in Section 5.3) was beyond the scope of this study.

2 Overview of the NYISO wholesale electricity markets

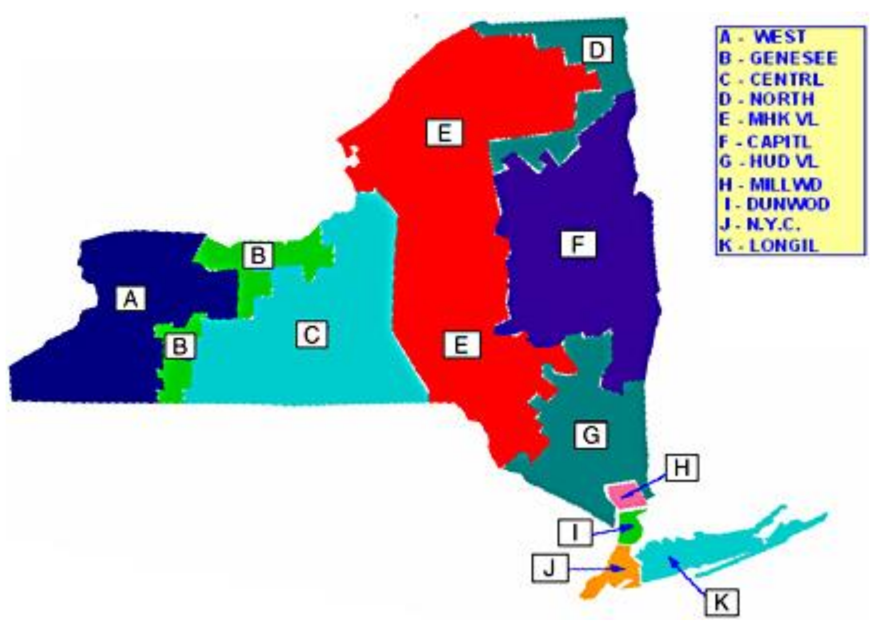
In November 1999, New York State's competitive wholesale electricity markets were opened to utility and non-utility suppliers and consumers as the NYISO began its management of the bulk electricity grid. The NYISO operates markets for energy, capacity, ancillary services and Transmission Congestion Contracts ("TCC") in New York State.

For the summer of 2015, there are 38,666 MW of installed capacity located in the New York Control Area ("NYCA" or the entire New York State). The annual energy usage in the state for 2015 is forecasted at slightly over 160TWh. The summer 2014 peak load in NY was 29,782MW, while the historic highest peak load was 33,939 MW in 2006.

The NYISO wholesale energy market design is based on a Location-Based Marginal Pricing ("LBMP") energy market design. Under an LBMP system, energy prices are established at various nodes on the transmission system. Price differences arise across nodes because of transmission losses and when there is congestion on the system preventing the flow of power. Generators are paid the LBMP at the node where they are located while loads pay a zonal price (the average demand-weighted LBMP within the zone where the load is located).

The NYCA is divided into eleven load zones as shown in Figure 6.

Figure 6. NYCA Load Zones



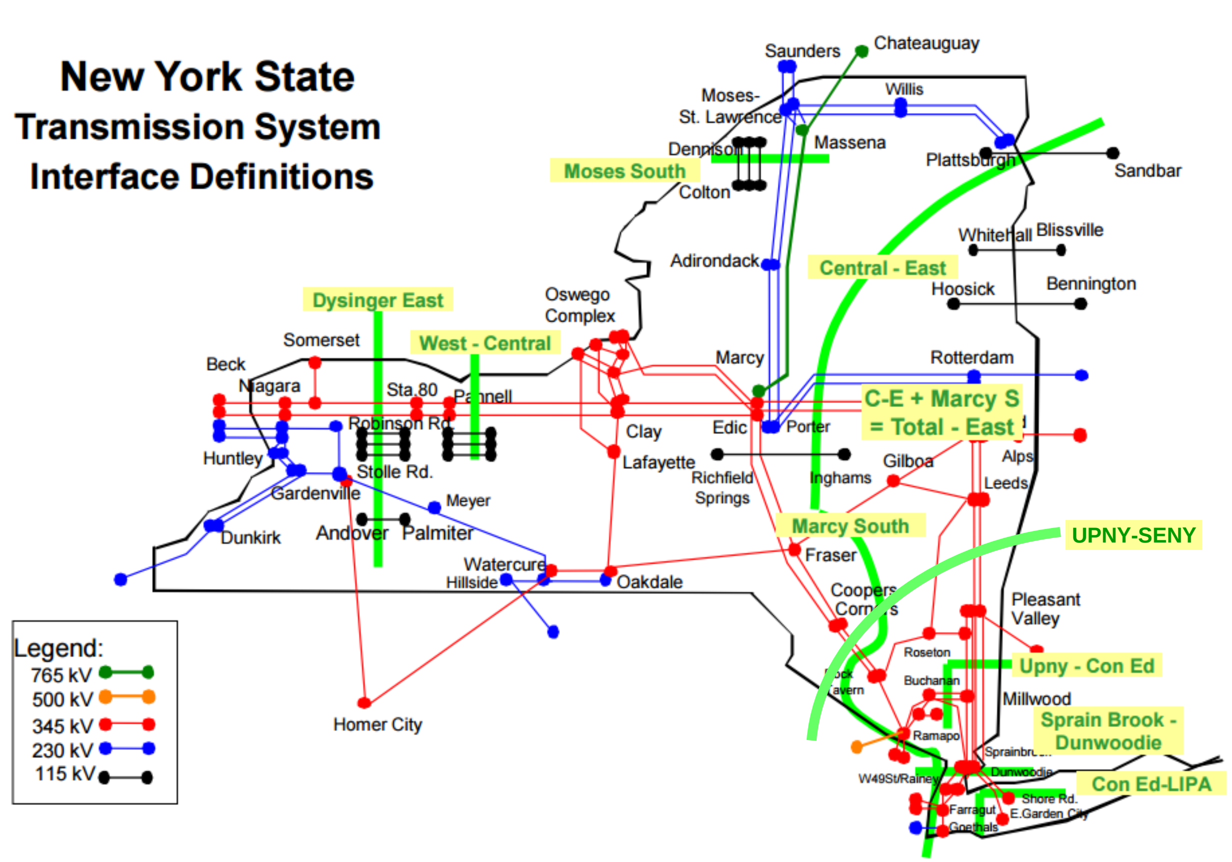
Source: NYISO

2.1 NYCA Transmission System

There are several internal transmission interfaces within the NYCA which impose transfer limitations on energy flows between different regions of the state. Figure 7 illustrates the NYCA transmission system backbone and highlights the key transmission system interfaces.

In New York, energy flows from West to East and from North to South towards the largest load zones which are New York City ("NYC" or zone J) and Long Island ("LI" or zone K). The Central-East ("C/E") interface is typically used as a boundary when referring to western NY (zones A-E) and eastern NY (zones F-K). The C/E interface, together with the UPNY/SENY interface which separates the Mohawk Valley (zones E) and Capital (zone F) regions from the Lower Hudson Valley region ("LHV" - zones G, H and I), are the focus of this report.

Figure 7. NYCA Transmission interfaces



Source: NYISO

2.2 Historical energy and capacity market trends

LBMPs are composed of three elements: marginal cost of energy, marginal costs of congestion and marginal transmission losses. There has always been a difference in energy price between load zones or regions within the NYCA, because of both losses and congestion, although congestion is by far the larger factor. Capacity market prices have also been higher in certain regions that are effectively transmission constrained and require more local supply. For example, Load Serving Entities ("LSE") serving load in NYC are obligated to procure a certain percentage of their capacity requirement from generators located in the same zone, and there is a tight supply-demand balance for this requirement. As such, NYC capacity prices have been higher than the prices in other parts of the state. Figure 8 and Figure 9 illustrate respectively the historical difference in energy and capacity prices across different NYCA regions.

Figure 8. Historical NY energy prices for select zones

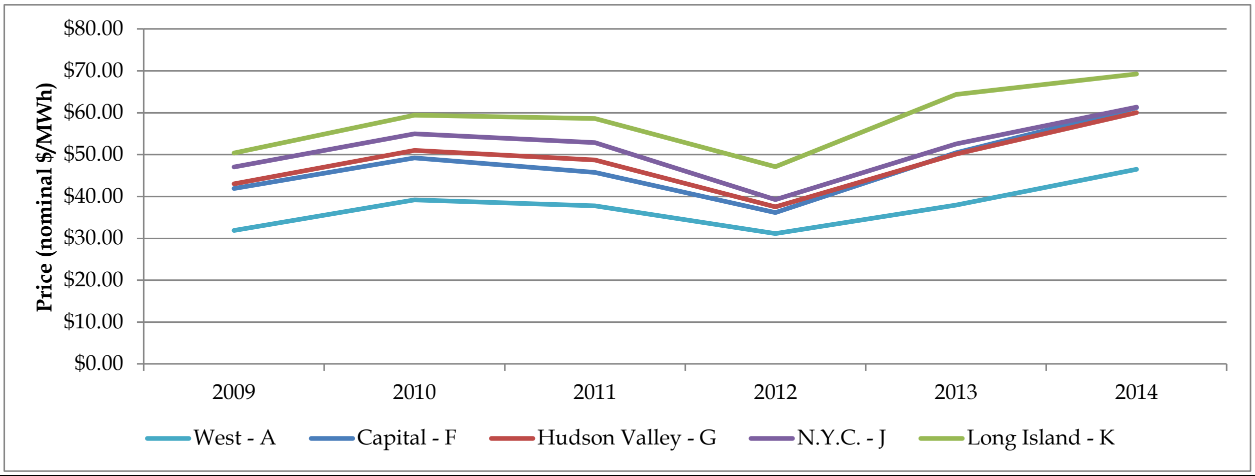
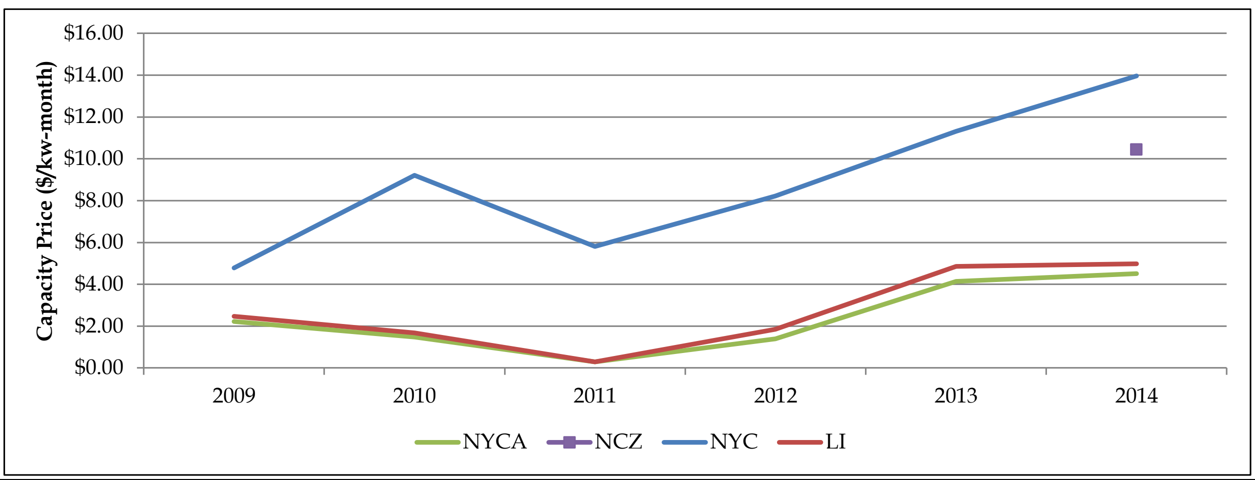


Figure 9. Historical NY capacity prices by zone



Although the magnitude of the actual price difference has varied from year to year, historically energy and capacity prices have always been higher in the LHV, NYC and LI when compared to western NY regions.

2.3 Historical Congestion on C/E and UPNY/SENY Interfaces

A few key transmission interfaces within the NYCA are responsible for most of the congestion observed in the energy market. Historically the C/E, UPNY/SENY and lines leading into NYC have been the most congested interfaces, although in recent years congestion on the C/E interface has dwarfed all others.

Figure 10 illustrates the major sources of congestion value in the Day Ahead Market ("DAM") as reported by NYISO's Market Monitoring Unit ("MMU").[7] The MMU defines congestion value in the same way as LEI measures it in its study, namely the sum, over all pricing intervals of a given period, of the difference in the congestion component of the LBMP between two zones multiplied by the energy flows between the two zones in that same given period.

From 2009 through 2011, the NYC Lines[8] represented the transmission interface with the highest congestion value within NYCA, hovering around $150 million annually. C/E had a congestion value between $75 million and $100 million annually, Capital to Hudson Valley between $50M and $80M annually and Long Island between $38 million and $53 million. As a reference, the total cost of energy in the wholesale market in 2014 was about $11 billion[9].

The NYC Lines congestion value decreased significantly in 2012, while in 2013 the C/E congestion value increased so much as to dwarf all other interfaces. Capital to Hudson Valley congestion has also been declining since 2011. There are many factors which can explain the shifts in transmission congestion patterns, such as natural gas prices, supply changes and transmission outages.

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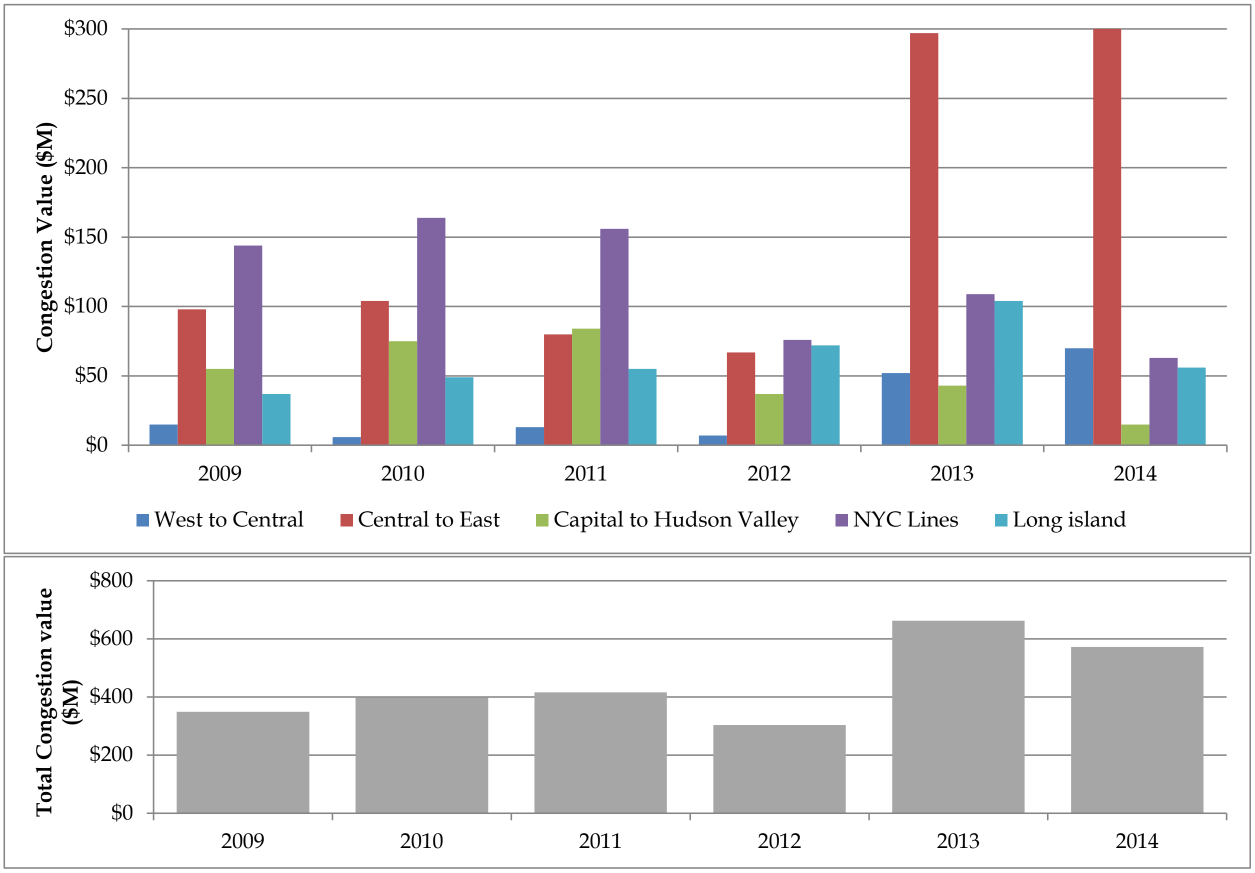
[7] Congestion value is reported by NYISO's Market Monitoring Unit (Potomac Economics) as part of the quarterly and yearly *State of the Market* reports.

[8] The congestion value reported for "NYC Lines" aggregates the congestion value from the NYC 345kV network and from load pockets within NYC

[9] NYISO Power Trends 2015, published June 2015

Figure 10. NYCA historical transmission congestion value (DAM)



Source: Potomac Economics, *State of the Market* reports, 2010-2014

For instance, total DAM congestion value was down 26% in 2012 from 2011, most noticeably the market value of congestion on the NYC Lines fell by 50% over that period. The factors identified by the MMU to account for this reduction in transmission congestion value are as follows:

- overall lower natural gas prices in 2012 as compared to previous years decreased west to east congestion, as eastern NY satisfies a substantial portion of its demand with power from western NY and is more dependent on gas-fired generation;
- overall lower natural gas prices also decrease the cost of redispatching resources to manage congestion, therefore reducing the overall congestion value;
- 1,000 MW of new generation[10] became operational in NYC between July 2011 and July 2012; and

[10] 660 MW Astoria Energy II Combined Cycle and 512 MW Bayonne Energy Center peaking plant

- clockwise loop flows around Lake Erie decreased from previous years following the commissioning of new equipment on the regional transmission network, reducing the congestion on west to east transmission interfaces.

Conversely, the total 2013 DAM transmission congestion value across all interfaces increased by 120% from the 2012 value. This increase was directly attributable to the C/E interface, for which the congestion value increased almost 5-fold. Several factors contributed to the higher 2013 congestion value as compared to previous years:

- a greater spread in natural gas prices when compared to previous years between western and eastern NY caused a significant disparity in production costs between gas-fired plants in eastern NY (higher cost) and western NY (lower cost), and therefore gas-fired plants in western NY were more frequently scheduled for dispatch. The resulting increase in west to east flows on the C/E interface caused a significant increase in congestion value;
- higher overall natural gas prices also increased the cost of redispatching resources to manage congestion, therefore increasing the overall congestion value;
- congestion on the 230kV lines in the West zone (zone A) increased in 2013 following the retirement of several coal units that helped relieve this congestion;
- the MMU also noted that lengthy transmission and generation outages in the West zone (zone A) also contributed to the higher congestion value; and
- significant congestion in Long island was caused by outages and deratings of the Neptune Cable and the 345 kV lines feeding the zone from western NY.

Finally, in 2014, while the C/E congestion value remained identical to the 2013 level, overall DAM congestion value was down 13% year-over-year as a result of reduced congestion on the NYC Lines, LI lines and the Capital to Hudson interface.

- the decreased congestion on the NYC Lines, LI lines and the Capital to Hudson interface was largely due to lower load levels and lower natural gas prices in the second to fourth quarters of 2014;
- the 2014 reduction in congestion into the LHV was partially the result of fewer Thunder Storm Alerts ("TSAs")[11] events being declared with respect to 2013; and
- C/E congestion occurred mostly in the first quarter of 2014 when the large spreads in natural gas prices between western NY and eastern NY led to increased flows on the interface.

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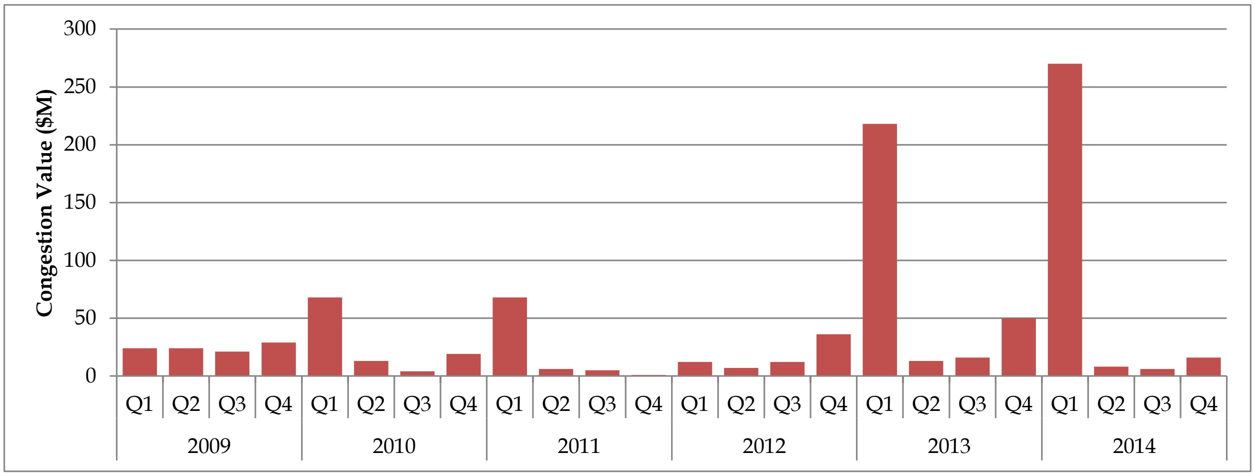
[11] TSAs are declared when NYISO forecasts the possibility of thunder storms in the vicinity of the UPNY/SENY interface. Flows on transmission lines leading into LHV are reduced as a result of the TSA to mitigate the effect from the potential loss of one line following a lightning strike.

2.3.1 Central-East

The C/E interface limits flows from historically less expensive generation in the western part of NY to the eastern load zones of the LHV, NYC and LI.

Figure 11. Historical Central East congestion value (DAM) by quarter



Source: Potomac Economics, Quarterly Reports 2010-2014

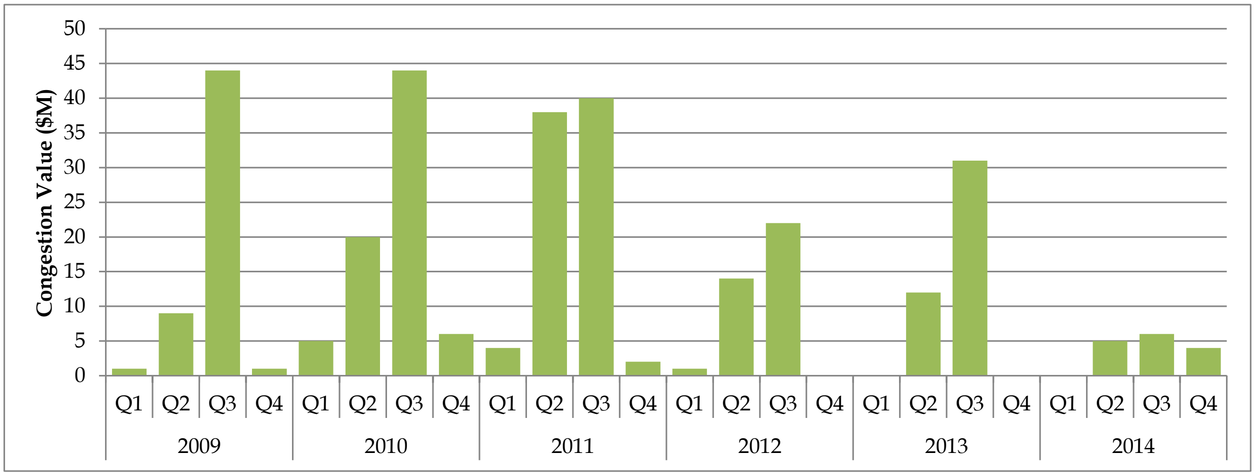
As can be seen from Figure 11, C/E congestion follows a seasonal pattern. Most of the congestion has historically been observed during the winter months in the first quarter and to a lesser extent in the fourth quarter. As will be discussed in Section 5.3.2, the congestion on this interface is strongly correlated to the spread between western NY and eastern NY natural gas prices. Historically, that spread has been largest during the winter period and is exacerbated during periods of extreme cold (such as in the winters of 2014 and 2015 as seen in Figure 19).

2.3.2 UPNY/SENY

The Capital (zone F) to Hudson Valley (zone G) interface ("UPNY-Con Ed" or "UPNY-SENY") limits flows from Western NY and the Capital zone (zone F) to the LHV, NYC and LI.

As can be seen from Figure 12, UPNY/SENY congestion also follows a seasonal pattern. However, where the C/E congestion occurs mostly during the winter period, UPNY/SENY is congested the most during periods of high demand in the summer months. This pattern will be discussed in greater detail in section 5.3.1.

Figure 12. Historical UPNY/SENY congestion value (DAM) by quarter



Source: Potomac Economics, Quarterly Reports 2010-2014

2.4 Congestion in the capacity market

In the summer of 2014, the NYISO created the NCZ in the capacity markets. This new zone was created to reflect the requirement for more generation resources to be located in the LHV region because of transmission constraints (such as the UPNY/SENY interface) that might prevent the deliverability of capacity resources from elsewhere in the NYCA to the LHV during periods of stress on the system (such as high load or following transmission outages or deratings). Therefore, the NCZ much like the other capacity localities (NYC and LI) is a direct result of transmission constraints and represents a form of congestion in the capacity markets.

Since transmission capacity into the NCZ is limited, the amount of capacity that the LSEs must procure from local generators causes strained levels of local supply relative to local demand and result in higher prices for consumers located in the zone.

To the extent that congestion costs in the energy market are meant to capture the value of limited transmission resources, then capacity market price differences also do the same on the basis of the remuneration necessary to motivate the right locational investment.

3 Modeling approach

LEI uses simulation models to forecast energy and capacity prices. As the wholesale electricity market trends are influenced by fundamental parameters such as load levels, supply mix, transmission constraints or cost of fuel, it is necessary to model these fundamentals in order to forecast future market trends. When looking out over the longer term, it is not sufficient to assume that history will repeat itself or that near term forward prices are indicative of longer term prices. The NYISO employs such modeling techniques to produce long term outlooks, the Congestion Assessment and Resource Integration Study ("CARIS") report being one example.

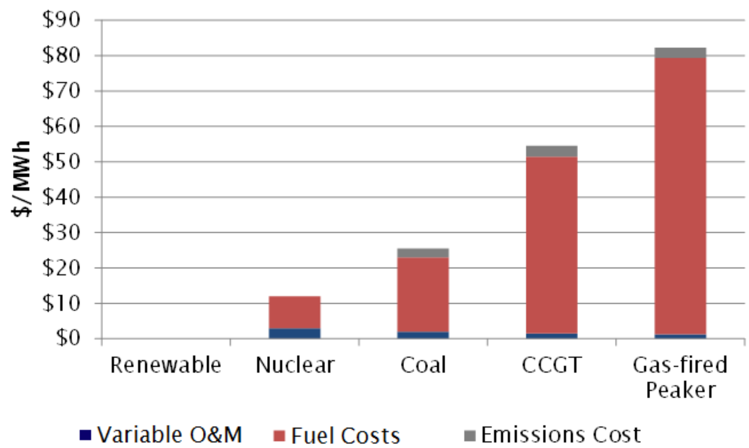
LEI employs a proprietary simulation model, POOLMod, as the foundation for its electricity price forecast. POOLMod has been used successfully to model the NYISO and markets in other jurisdictions for regulatory proceedings, in the context of investment appraisal and asset valuation, for financing support, and in a variety of other projects, as detailed in Appendix A.

POOLMod simulates the economic dispatch of generating resources in the energy market subject to least cost dispatch principles to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission. LEI assumes a perfectly competitive landscape where energy suppliers submit offers based on their Short-Run Marginal Costs ("SRMC"). SRMC represent the variable cost incurred by a supplier to generate energy.

The major components of SRMC include cost of fuel and costs associated with variable operation, maintenance and administrative ("OM&A") expenses that vary with the level of output. For combustion turbines, diesels and fossil-fired units that require emission allowances to operate, CO_2, SO_2 and NOx allowance costs are also part of the SRMC. Figure 13 illustrates generic SRMC by fuel type[12].

[12] These numbers are based on generic parameters and costs for each type of generation resource. The values are for illustrative purposes and should not be considered representative of any particular plant.

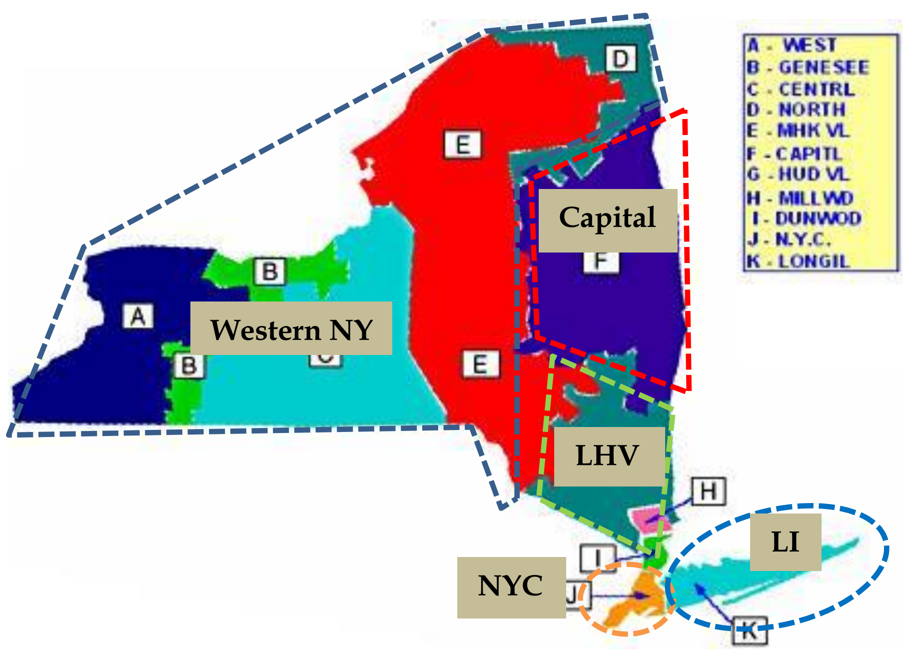
Figure 13. Illustrative example of SRMC by fuel type



In addition, POOLMod is a transportation-based model, giving it the ability to take into account transmission limits for the key internal and external NYCA transmission interfaces. LEI relies on thermal or stability interface transmission limits published in documents such as Operating Studies or elsewhere on the NYISO OASIS website, as well as values obtained from power flow studies. Appendix B describes the POOLMod model in greater details.

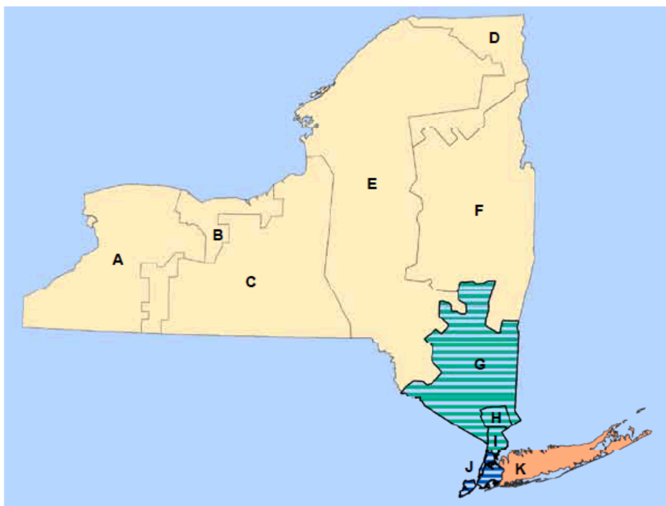
For modeling the energy market, LEI groups the eleven NYCA load zones into five distinct sub-regions based on the major transmission interface constraints in the state. Therefore, LEI models a Western NY ("WNY") zone comprised of zones A, B, C, D, and E; Capital ("CAP") is zone F; Lower Hudson Valley ("LHV") represents zones G, H, and I; NYC is Zone J; and LI is Zone K.

Figure 14. Aggregated NYISO zones



NYISO's capacity market is also locational, with four nested localities: NYCA, New York City (Zone J), the Lower Hudson Valley (also known as the New Capacity Zone ("NCZ"), which encompasses zones G to J), and Long Island (Zone K). NYC is nested within the NCZ, while the NCZ and LI zones are nested within the NYCA zone. These localities have been created by the NYSIO to reflect transmission constraints between regions and the necessity for local generation resources. The NYISO determines a Locational Capacity Requirement ("LCR") for each of the sub-zones, which represents the minimum amount of capacity which must be procured from generators located within that zone. The Demand Curve parameters are also calculated so as to reflect the economics specific to each locality. The results are locational capacity prices which reflect the value of capacity in different regions within NY State.

Figure 15. NYISO capacity zones

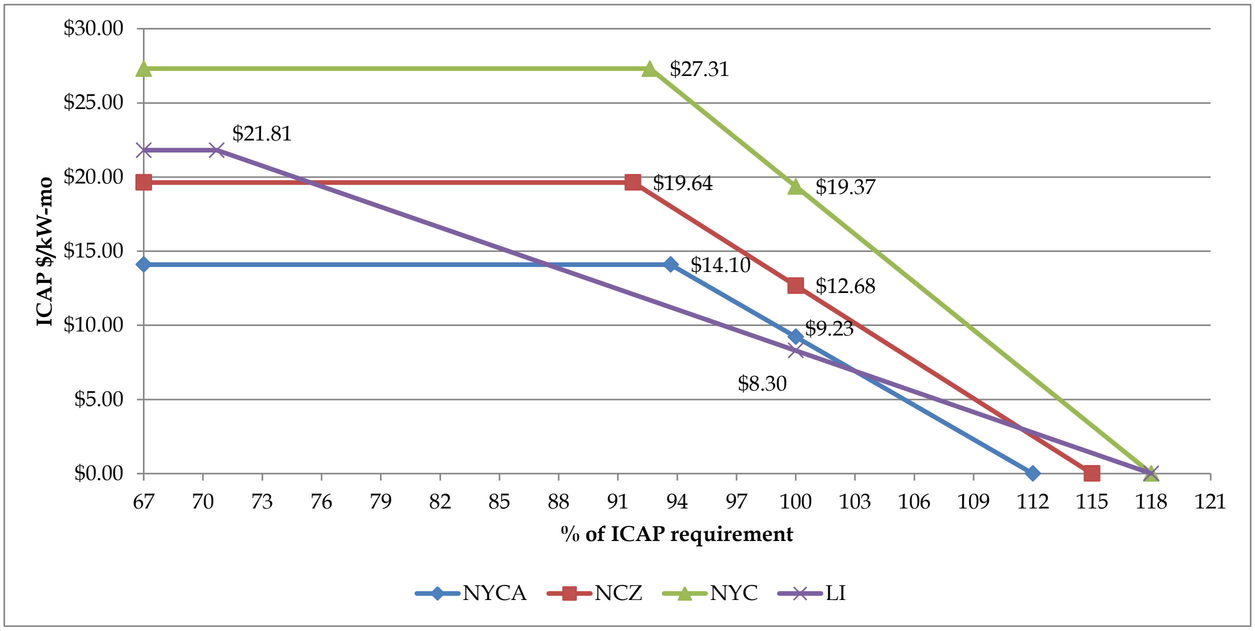


Source: NYISO

LEI uses an Excel-based model to simulate the NYISO's spot[13] ICAP auctions, in order to project a capacity price forecast for all of the NYISO capacity zones. LEI models a capacity demand curve from parameters determined by the NYISO as part of the triennial Demand Curve Reset ("DCR") process, and extrapolates the demand curve for future years as further described in section 9.10. Figure 16 illustrates the 2016-2017 capacity spot auctions demand curve.

[13] The NYISO relies on a spot capacity market (as opposed to a forward looking market such as ISO-NE or PJM) and as such the demand curve is used in the spot auctions, which are held on a monthly basis.

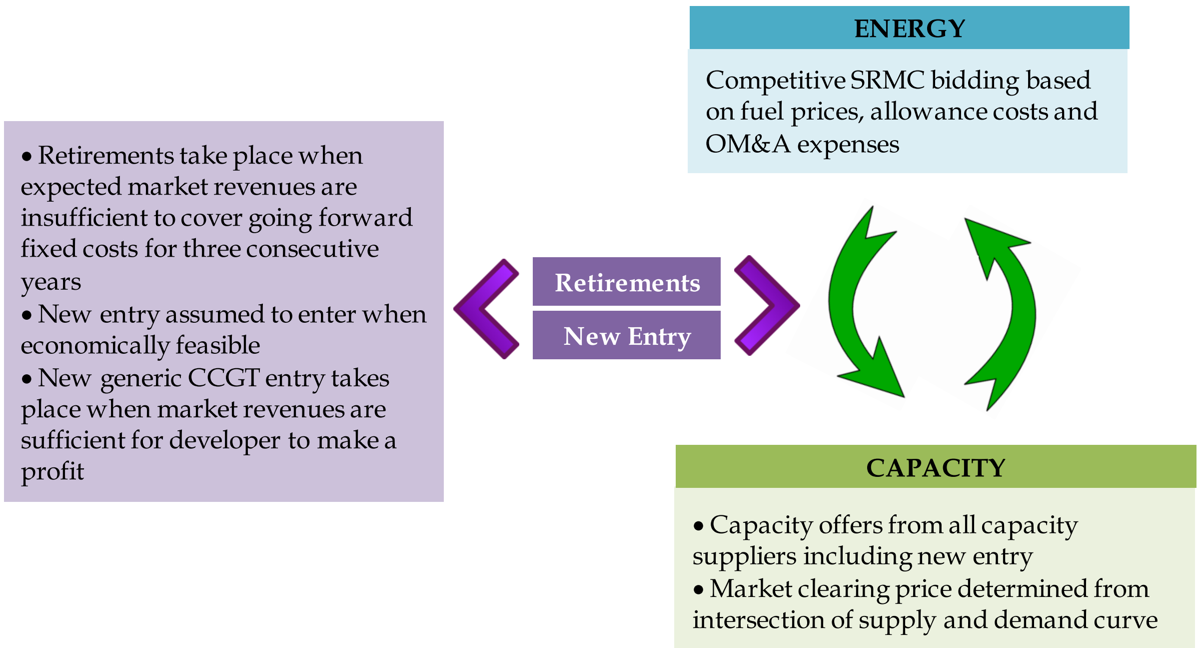
Figure 16. 2016-2017 capacity spot auctions demand curve



In order to be able to replicate economically rational entry and retirement decisions, LEI simulates the energy and capacity markets on an integrated basis. LEI tracks the profits that existing and new capacity are projected to earn across these markets. The modeling for the New York power market represents the linkages between energy and capacity market designs and considers the specific capacity market institution. For example, LEI models a downward-sloping demand curve for the capacity price forecast, consistent with current market rules and parameters approved by FERC.

The diagram below, Figure 17, highlights the process and sequencing used in the modeling and the inter-relationships between the energy and capacity models, as well as the entry and retirement decisions of resources.

Figure 17. Flow diagram of energy, ICAP modeling



3.1 Energy and capacity modeling: why did LEI model separate scenarios?

To accurately forecast capacity prices, energy prices and congestion within the NYCA, it is imperative to rely on a solid set of assumptions for the model parameters. Supply sources, load forecast, import and export transactions, emissions costs and interface limits are all important factors to consider when preparing a forecast. However, no input is arguably more important than the fuel prices forecast, specifically for natural gas prices in a market like NYISO. See Figure 38 for an illustration of the supply fuel mix by region in NY. Considering that gas-fired generators within the NYCA use different gas pricing points to procure their fuel, the absolute price level and basis differential between the different natural gas pricing points have a profound effect on the electricity prices forecast.

There are multiple sources of natural gas price forecasts, each with a different outlook on the future of natural gas prices. Therefore, in an attempt to illustrate the effect of fuel prices on the prices of electricity and value of congestion within NY, LEI has prepared its current NY market outlook under three different gas pricing scenarios, each taking a different perspective on natural gas prices as detailed in section 3.1.2.

3.1.1 Energy and capacity market modeling assumptions

LEI's forecast represents a base case outlook which combines the most likely set of market assumptions for key market drivers along with normal system operations and average load conditions, based on NYISO's "50/50" load forecasts. The base case also builds on conservative market-oriented expectations for marginal costs of generation, including fuel prices, variable O&M costs, and carbon allowance prices. LEI assumes that the NYISO wholesale electricity market converges and maintains a balanced supply-demand profile over the longer term (i.e., that reserve margin requirements are generally met in each year and new investment is made when it is economic). Therefore the base case represents a future evolution from the current status quo, based on economically rational investor response to the projected market dynamics and system needs.

LEI used the same supply resources (including retirements and new entry) for all natural gas scenarios as the variation in energy and capacity revenues between the different scenarios is not sufficient to change the timing of retirements or new entry.

The table below in Figure 18 summarizes modeling assumptions employed in the energy and capacity market price forecast for major categories of modeling assumptions, such as transmission and market topology, fuel prices, emissions allowance cost, hydrology, cost of generic new entry, import and export schedules, forecast load (demand) and form of new supply.

A detailed review of all assumptions used by LEI in modeling of the energy and capacity markets is presented in appendix C.

Figure 18. Summary of key assumptions for wholesale market energy and capacity price forecast

Parameter	Assumptions
Topology	NYISO is modeled as five distinct regions based on the primary sources of congestion in the state. NYISO is also connected to PJM, New England, Ontario and Quebec
Supply	Existing supply in the NYISO is based on the 2015 Gold Book published by NYISO as of April 2015. Additional new entry is introduced if and when economically feasible given the simulated market dynamics. Plants exit the market when their revenues cannot cover the going forward fixed costs in 3 consecutive years, consistent with economically rational retirement rules.
Generator parameters	LEI supplements the Gold Book data with plant operating parameters (heat rates, variable O&M, forced outage rate, etc…) from a commercial database which relies on NERC GADS data
Demand	LEI relies on the NYISO energy and demand forecast from the 2015 Gold Book, extrapolated over the forecast horizon
Gas prices	LEI prepared 3 natural gas pricing scenarios for modeling the NYISO wholesale electricity markets
Coal prices	LEI assumptions are based on the 2014 average delivered price of each plant escalated in nominal terms using the annual rate of change implied in the coal price index and inflation rate fro EIA's 2015 AEO
Oil prices	The distillate oil price index is based on NYMEX heating oil forwards. Oil price indices are escalated based on the EIA 2015 AEO long term forecast for crude oil
Emissions	LEI uses forwards for near-term pricing of emissions credits. Long term prices are escalated with inflation
Hydrology	LEI relies on historical monthly production data for the individual plants to create typical monthly energy budgets for each plant, considering historical output over the last 5 years.
Capacity Demand Curve parameters	LEI uses uses parameters from the latest auctions such as the ICR and LCR. LEI further uses the Gross CONE from the latest Demand Curce Reset process (escalated for inflation) and uses its own outlook on energy revenues to calculate the Net CONE and Reference Point

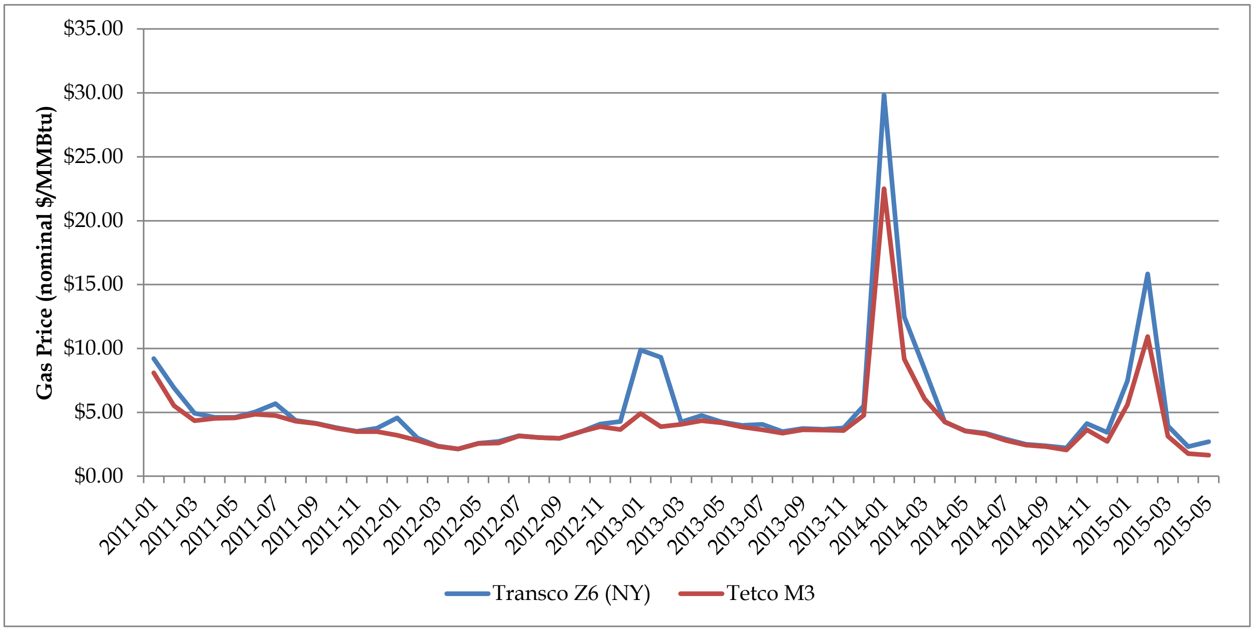
3.1.2 Natural gas price projections

As discussed further in section 5.3.2, natural gas prices are an important driver of electricity costs and congestion in NY. Not only is the actual level of natural gas price significant but also the basis, or spread, between pricing hubs. In order to reflect the actual fuel costs of gas-fired generators in various regions of the state, LEI uses three gas trading hubs as proxies for generators according to their location:

- Tetco M3 for generators located in Western NY (zones A through E)
- Iroquois Z2 for generators in Capital (zone F) or the LHV (zones G-H-I)
- Transco Z6 (NY) for generators located in NYC and LI (zones J–K)

As can be seen from Figure 19 which illustrates historical prices for the trading hubs, the basis (price difference) between the western NY trading hub for natural gas (Tetco M3) and the eastern NY trading hub (Transco Z6 (NY)) is mostly apparent during the winter months, when gas demand is highest due to gas-driven heating load. During the winter, there is propensity for gas prices to spike when demand starts to reach the limits of pipeline capacity to deliver gas supply to a specific hub.

Figure 19. Historical natural gas prices



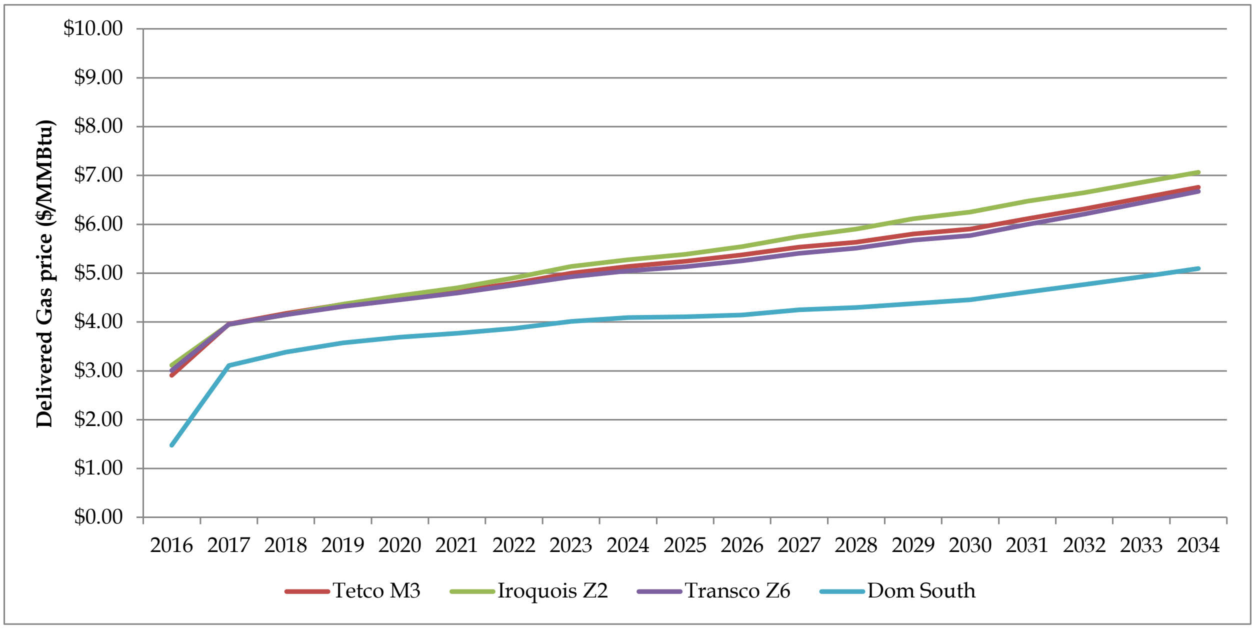
Source: SNL

Natural gas price forecasts carry a lot of uncertainty because of possible variations in the fundamentals used to create them. These uncertainties are similar to those in the energy markets, such as variations in supply, variations in demand caused by weather or other economic factors, or transportation constraints. Because of the significance of natural gas prices for electricity prices and congestion within NY, LEI elected to model 3 separate natural gas price forecasts to assess the effect of each on energy and capacity prices and congestion within NY.

Marcellus Shale gas with pipeline expansion scenario

This gas price scenario is based on the premise that the winter basis depicted in Figure 19 is largely the result of abnormally cold weather. Therefore, a weather-normalized natural gas price forecast would not exhibit a strong differential between western NY and eastern NY prices. Furthermore, this scenario assumes a continuation of the build out of new pipeline capacity observed in recent years to take away low cost Marcellus shale gas supply from the Mid-Atlantic region and bring into the New York and New England regions. Therefore, this scenario assumes that the long-term trend in prices for natural gas across the NYCA is referenced off and linked to the price of supply from the Marcellus Shale region (for example, the price at Leidy or the Dominion South trading hub), rather than conventional gas supply from the Gulf region. The forecast for natural gas prices under the *Marcellus Shale gas with pipeline expansion* scenario are illustrated in Figure 20.

Figure 20. Natural gas price forecast for the *Marcellus Shale gas with pipeline expansion* scenario

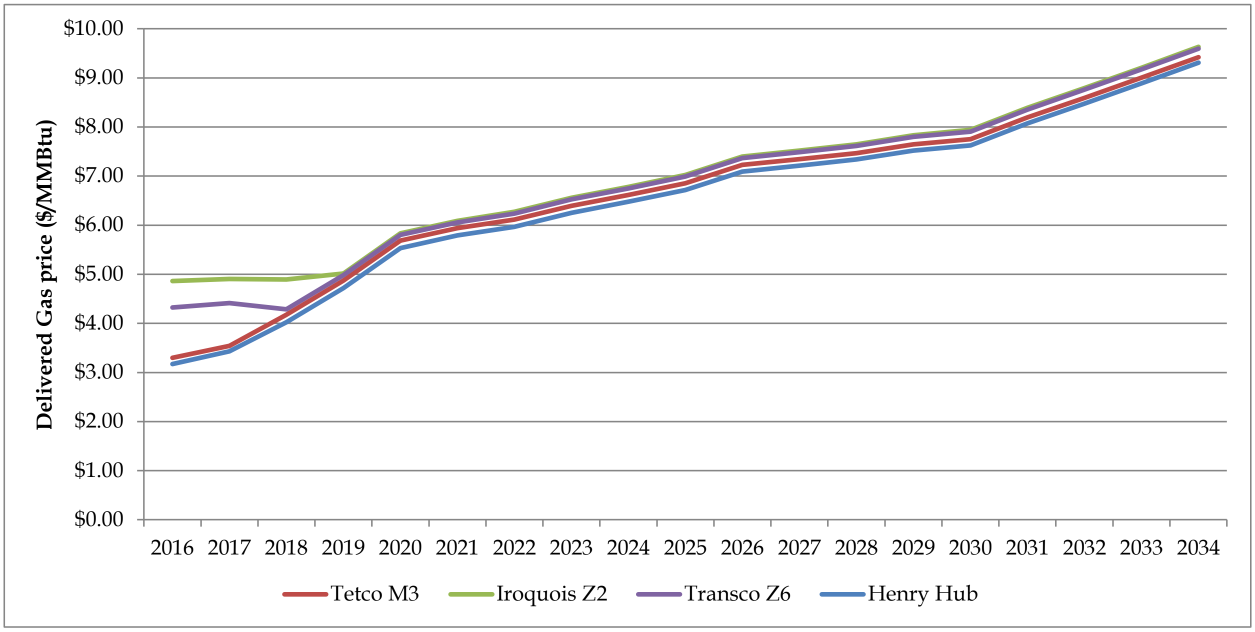


Henry Hub gas with pipeline expansion scenario

This gas price scenario assumes that the marginal supply of gas in NYCA is linked to supplies originating from the Henry Hub, Louisiana, a source of conventional gas supply more expensive than Marcellus Shale supply under normal operating ranges. This scenario also assumes the short-term winter basis between natural gas prices in western versus eastern NY will remain similar to the value of recent years, about $0.90/MMBtu. Prices for 2016 and 2017 represent an average of forwards from recent months for these delivery points. There is also an implicit assumption of some level of pipeline expansion in the longer term. For later years, LEI's Levelized Cost of Pipeline ("LCOP") model constrains price spreads between major gas pricing hubs to the levelized cost of building new pipeline between different hubs. The effect is a reduced winter basis differential between Tetco M3 and Transco Z6 (NY).

The forecasted natural gas prices under the *Henry Hub gas with pipeline expansion* scenario are illustrated in Figure 21.

Figure 21. Natural gas price forecast for the *Henry Hub gas with pipeline expansion* scenario

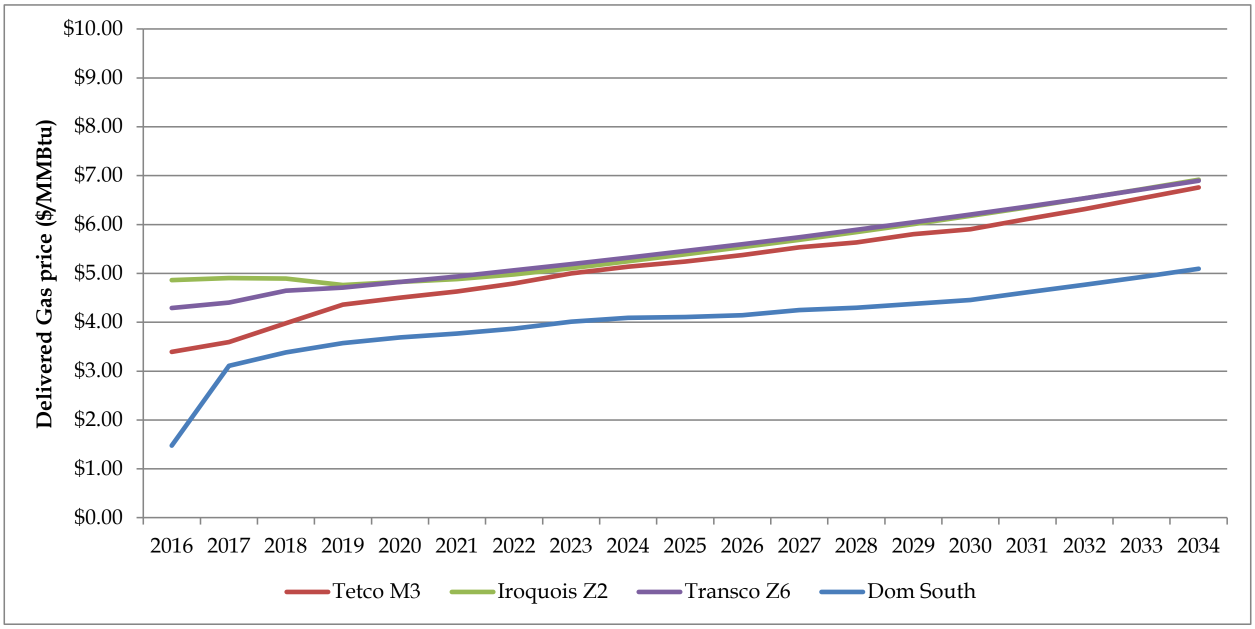


Marcellus Shale gas with persistent basis differential scenario

The third gas price scenario is based on the premise that the natural gas prices in eastern NY will trade at a premium to western NY, similar to what has been observed historically, even under normal conditions. In this scenario, LEI assumes that the marginal source of supply originates from the Marcellus Shale region, therefore the price levels are lower than in the Henry Hub gas scenario above. But because of more limited pipeline build-out in the Northeast United States, there is a persistent differential in gas prices. The current annual forecasted basis differential between Tetco M3 and Transco Z6 (NY) is around $0.90/MMBtu, which LEI uses for the 2016-2017 period. LEI then projects the annual basis gradually dropping to an annual persistent value of around $0.30/MMBtu under this scenario.

The forecasted natural gas prices under the *Marcellus Shale gas with persistent basis differential* scenario are illustrated in Figure 22.

Figure 22. Natural gas price forecast for the *Marcellus Shale gas with persistent basis differential scenario*



4 Forward Outlook for the NY Wholesale Power Markets

4.1 Energy Market

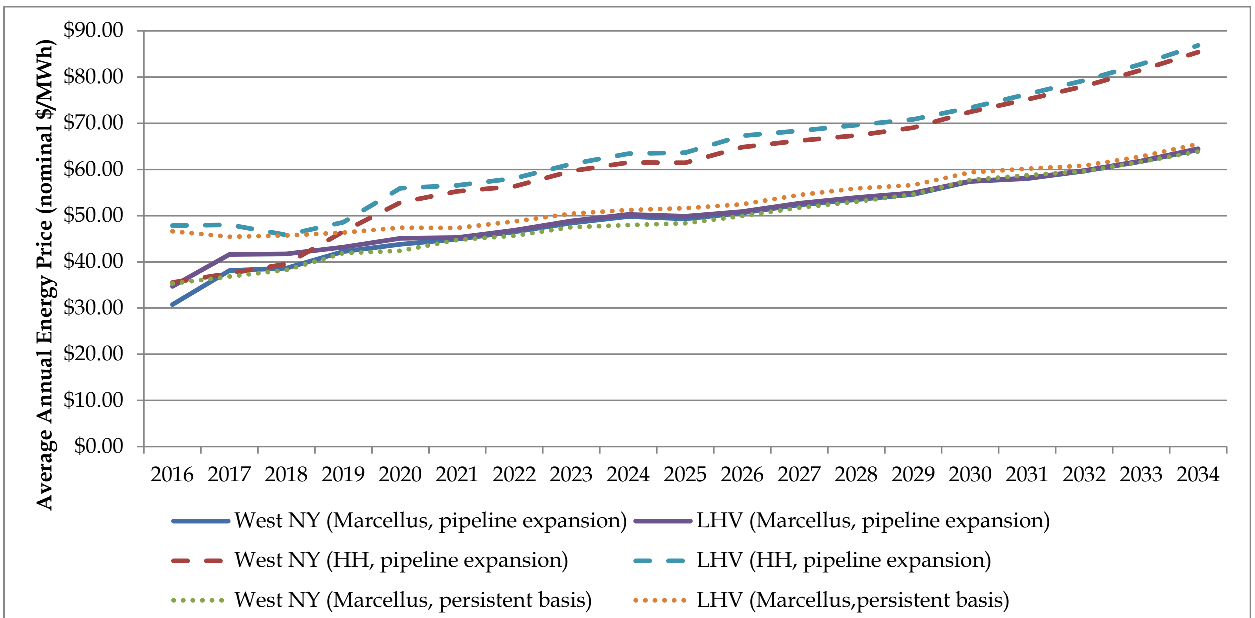
LEI's outlook for energy markets shows the price differential between eastern NY and western NY declining over time in conjunction with the basis differential in natural gas prices in these regions. Annual congestion value on the C/E and UPNY/SENY interfaces is forecasted to decline by a range of between 70% and 85% by 2030 as compared with the 2016-2017 levels, depending on which gas price outlook is used.

In addition to the reduced difference between natural gas prices in western versus eastern NY, supply changes play a significant role in reducing congestion in the energy markets. For example, new generation coming online in eastern NY together with the retirement of baseload generation in western NY tends to reduce congestion.

4.1.1 Energy market price outlook

Under all three gas pricing scenarios, energy price differences between western and eastern NY regions decline over time together with the basis differential in natural gas prices for these two regions. Absolute prices, however, are a function of delivered gas prices, with energy prices under the scenario using Henry Hub gas prices as a reference trending about 30% higher than prices under scenarios using Marcellus Shale gas prices as a reference. Figure 23 illustrates energy prices for the West NY and LHV zones over the forecast horizon for all three natural gas price scenarios.

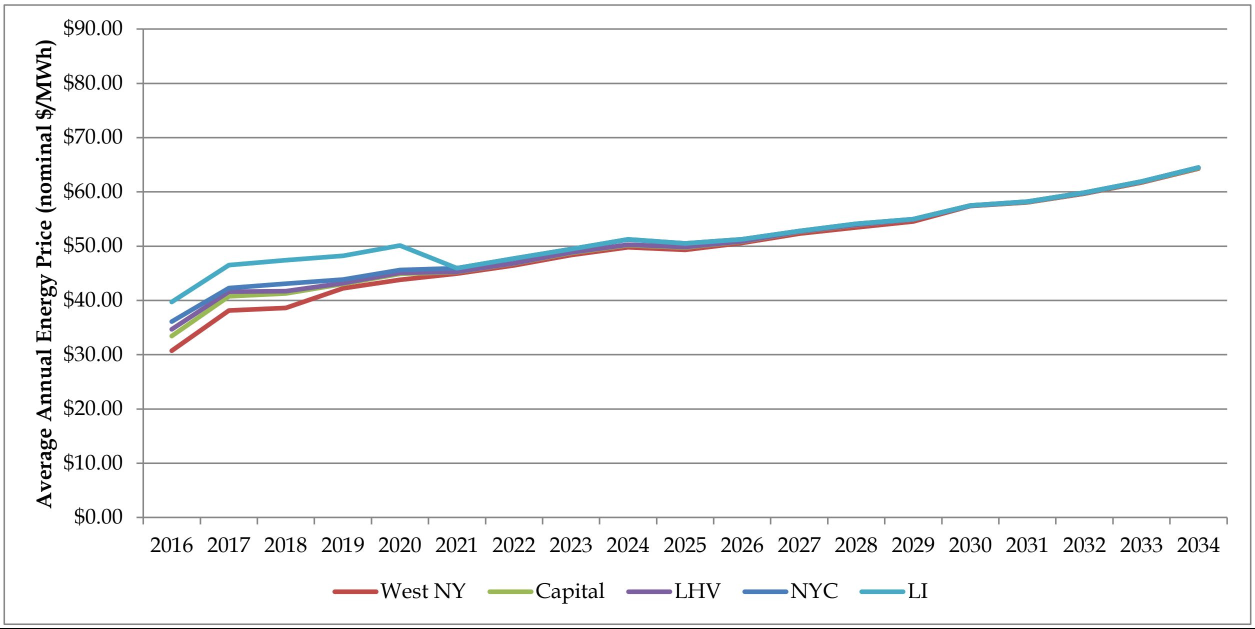
Figure 23. Forecasted annual energy market prices in the West NY and LHV zones under all natural gas pricing scenarios



Natural gas the Marcellus Shale gas with pipeline expansion scenario

Under this scenario, the 2016 price differential of around $4/MWh between Western NY and the LHV is gradually reduced as new generation comes online downstream of transmission constraints. Figure 24 presents the forecast of annual average energy market prices over the 2016-2034 horizon under the first natural gas pricing scenario, which assumes Marcellus Shale gas is the marginal source of supply of gas in New York for both western and eastern NY.

Figure 24. Forecasted annual energy market prices in the NYCA under *Marcellus Shale gas with pipeline expansion* natural gas pricing scenario



Average Western NY prices are forecasted at $30.7/MWh in 2016, while LHV prices are forecasted at $34.7/MWh for the same year. Prices start to converge in 2019 following the retirement of nuclear baseload generation in western NY (Ginna) followed by the entry of CCGT generation in NYC (Berrians I/II/III)[14], and are very similar by 2021 when the 750MW Caithness II plant starts operating.

[14] As LEI performed its analysis in the May through June 2015 timeframe, the Berrians project was still committed to the market and therefore included in NYISO's generation queue. This project had successfully completed the Class Year process to obtain rights to sell capacity ("CRIS" rights) in the NYC market. As such, it was included in LEI's base case composition of new resources. However, in late July 2015, NRG announced the withdrawal of several units that are part of the Berrians project. LEI believes however that this development does not significantly affect the forecast, as calculations in section 9.3 demonstrate that new resources in NYC in that timeframe should be close to being economic. It is therefore probable that other resources will commit to come online to replace the Berrians project in the coming years.

Energy prices in the long term follow the general trend in natural gas prices to reach $65/MWh by 2034. It is noteworthy that, while the modeled retirement of the Indian Point 2 1,000 MW nuclear generator has an impact on prices in 2034, the effect is spread over the entire NYCA since there is very little congestion apparent on the transmission network by that time.

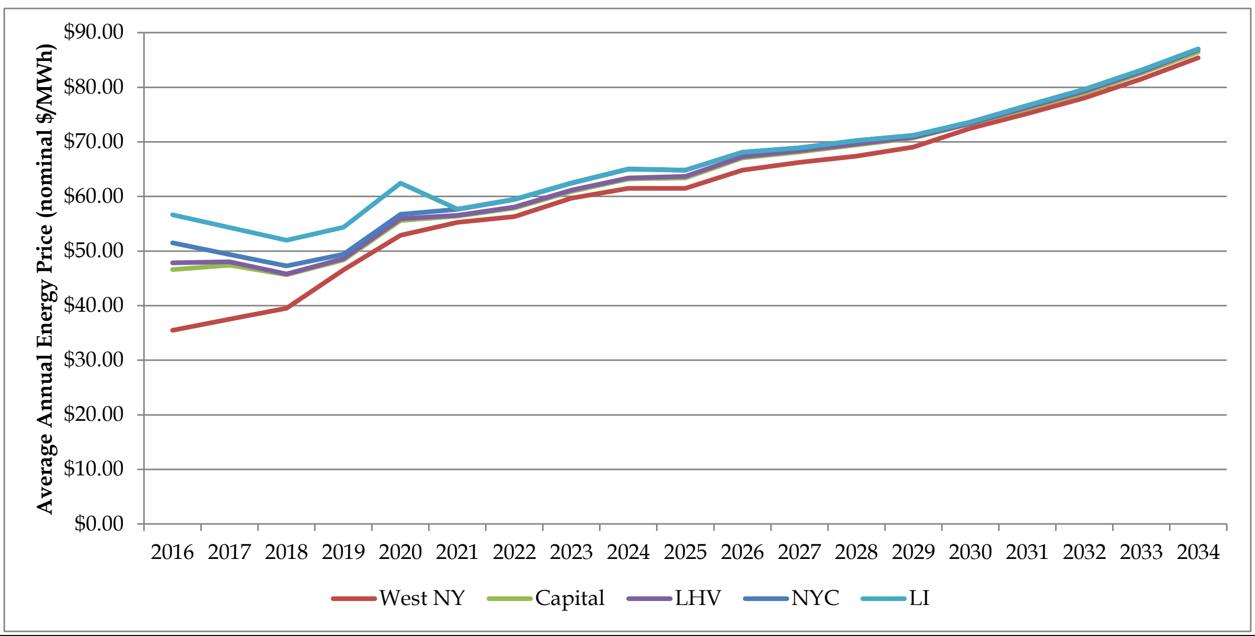
It is noteworthy that, should the retirement of such a major plant located downstream of the transmission constraints and at the door of NYC happen earlier when the system is more congested, the impact on C/E and UPNY/SENY congestion would be much more significant and lead to increased price separation between western and eastern NY.

Natural gas the Henry Hub gas with pipeline expansion scenario

Under this scenario, there is an initial price differential of around $12/MWh between Western NY and LHV due to the persistence of the price difference (basis) in natural gas pricing between western and eastern NY. By 2019, however, as the Iroquois Z2 and Transco Z6 (NY) prices converge with the Tetco M3 price, the difference in prices between Western NY and LHV drops to around $2/MWh.

Figure 25 presents the forecasted energy market prices over the 2016-2034 horizon under this natural gas pricing scenario, which corresponds to a Henry Hub reference for pricing trend and a winter basis differential between western and eastern NY natural gas prices which becomes minimal by 2018 due to assumed new pipeline construction.

Figure 25. Forecasted annual energy market prices in the NYCA under the *Henry Hub gas with pipeline expansion* natural gas pricing scenario



The convergence in energy prices, especially the rise in western NY prices, in further compounded by the retirement of the Ginna nuclear plant in western NY in 2019 and the entry of new generation downstream of transmission constraints. It is interesting to note that the difference in energy prices between eastern and western NY remains at around $2/MWh until 2029 (when a new CCGT comes online in NYC). In contrast, energy price results under the first natural gas pricing scenario discussed above (*Natural gas the Marcellus Shale gas with pipeline expansion*) showed convergence of the energy prices earlier in the modeling timeframe. This can be explained by the $0.10/MMBtu annual price difference in natural gas between western versus eastern NY in this scenario, as opposed to the first scenario which showed essentially no difference between the natural gas prices in the different hubs impacting the NY market.

Average Western NY prices are forecasted at $35.5/MWh in 2016, while LHV prices are forecasted at $47.9/MWh for the same year. For the reasons explained above, prices start to converge in 2019, reaching $46.6/MWh in Western NY and $48.6/MWh in the LHV.

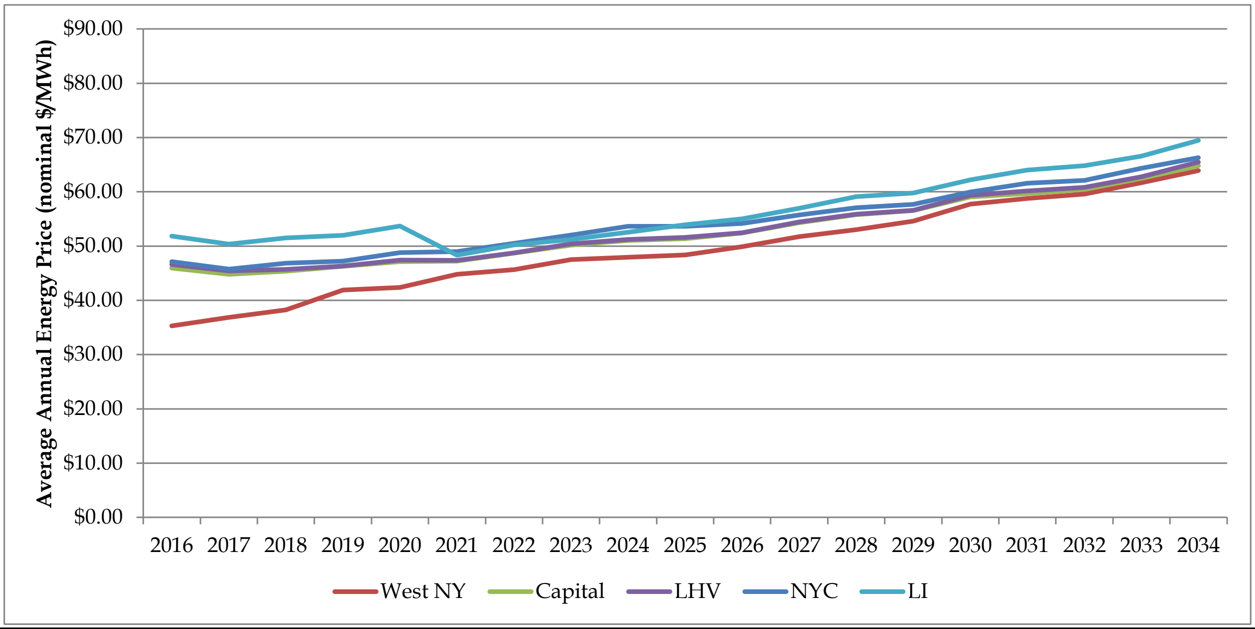
Energy prices in the long term follow the general trend in natural gas prices to reach the $85/MWh to $86/MWh mark by 2034 under this scenario. This higher price as compared to the *Marcellus Shale gas with pipeline expansion* gas pricing scenario is consistent with the natural gas forecast, with prices reaching about $9.5/MMBtu by 2034 as opposed to around $6.7/MMBtu in the first scenario.

Natural gas the Marcellus Shale gas with persistent basis differential scenario

Under this scenario, the same 2016 price differential of around $12/MWh between Western NY and LHV as in the *Henry Hub gas with pipeline expansion* scenario is observable. This energy pricing differential between western versus eastern NY then declines in 2019 to around $4.50/MWh together with the decline in natural gas price difference.

Figure 26 presents the forecasted energy market prices over the 2016-2034 horizon under this natural gas pricing scenario, which corresponds to Marcellus shale supply serving as marginal gas supply in New York. However, this third scenario assumes that there is continuation of a winter basis differential between western versus eastern NY natural gas prices through 2034.

Figure 26. Forecasted annual energy market prices in the NYCA under *Marcellus Shale gas with persistent basis differential* natural gas pricing scenario



However, as opposed to the *Henry Hub gas with pipeline expansion* scenario, the energy price difference between Western NY and LHV persists at around $4.5/MWh until 2019 (when a new CCGT comes online in NYC), after which it remains at around $2/MWh until 2034. In this scenario, the energy price differential between Western NY and LHV can be explained by the $0.3/MMBtu annual price difference in natural gas between western versus eastern NY.

Average Western NY prices are forecasted at $35/MWh in 2016, while LHV prices are forecasted at $46.6/MWh for the same year. For the reasons explained above, prices start to converge in 2019 to reach $41.9/MWh in Western NY and $46.3/MWh in LHV.

Energy prices in the long term follow the general trend in natural gas prices to reach the $64/MWh to $66/MWh (and closer to $70/MWh in LI). These prices are similar to the 2034 prices under the *Marcellus Shale gas with pipeline expansion* scenario as natural gas prices are forecasted to reach around $6.70/MMBtu in that year.

4.1.2 Implied market heat rates

Implied market heat rates are a means to allow for a comparison of market price trends by normalizing for gas price levels. Assuming that gas-fired plants are on the margin and set the price for energy in the wholesale markets, dividing the energy price for a particular period by the natural gas price for that same period gives an indication of the heat rate[15] of the marginal

[15] The heat rate of a generator represents the efficiency with which that plant can convert thermal energy into electricity.

units during that period. Therefore, as gas prices vary (but other factors remaining the same), the prices for electricity will vary but the marginal heat rate will not. However, the market heat rate can be less reliable an indicator for regions that are dominated by energy sources that do not rely on the price of gas for their offers such as NY's western region.

Figure 27 illustrates the modeled implied market heat rates for all regions within the NYCA over the 2016-2034 forecasting horizon for each of the natural gas pricing scenarios. For reference purposes, the historical heat rates from 2011 to 2014 are included on each of the figures.

Under all modeled natural gas pricing scenarios, the implied market heat rates converge over time as would be expected given the normalizing for gas price levels. Furthermore, the price of natural gas converges over time. The Capital and LHV zones market heat rates do tend to be lower in the *Marcellus Shale gas with pipeline expansion* scenario when compared to other zones as a result of the higher price for Iroquois Z2, used as the reference gas price in those regions, when compared to Tetco M3 and Transco Z6 in that scenario.

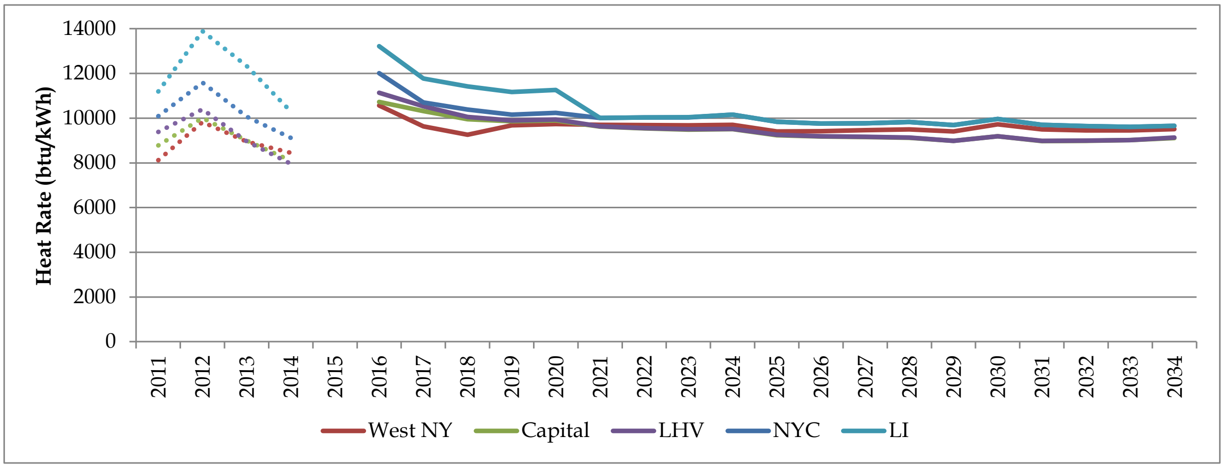
Furthermore, lower overall gas prices in the 2016-2017 timeframe when compared with 2014 will allow gas-fired resources to set the price more frequently than in 2014, when oil units became the marginal units during winter months when natural gas price spikes occurred and some pipelines were constrained from taking on more deliveries. As a result, market heat rates in general for the 2016-2017 timeframe are higher than in 2014.

It is noteworthy that the Western NY region heat rates are much more volatile than in other regions. Western NY is dominated by hydro and nuclear baseload generators as well as imports from neighboring jurisdictions (Québec, Ontario) whose offers are not correlated to the Tetco M3 gas price. Gas fired generators might not therefore be the marginal units as frequently as in other NYCA regions, especially in the off-peak periods.

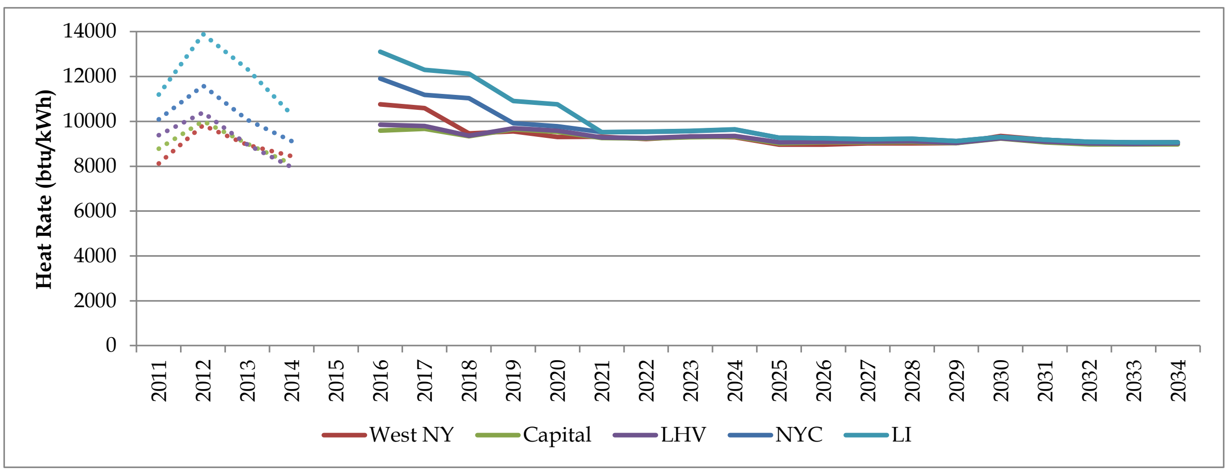
The general tendency is for heat rates to be flat or decline slightly over time, as new efficient generation comes online to replace older retired units.

Figure 27. Forecasted market heat rates

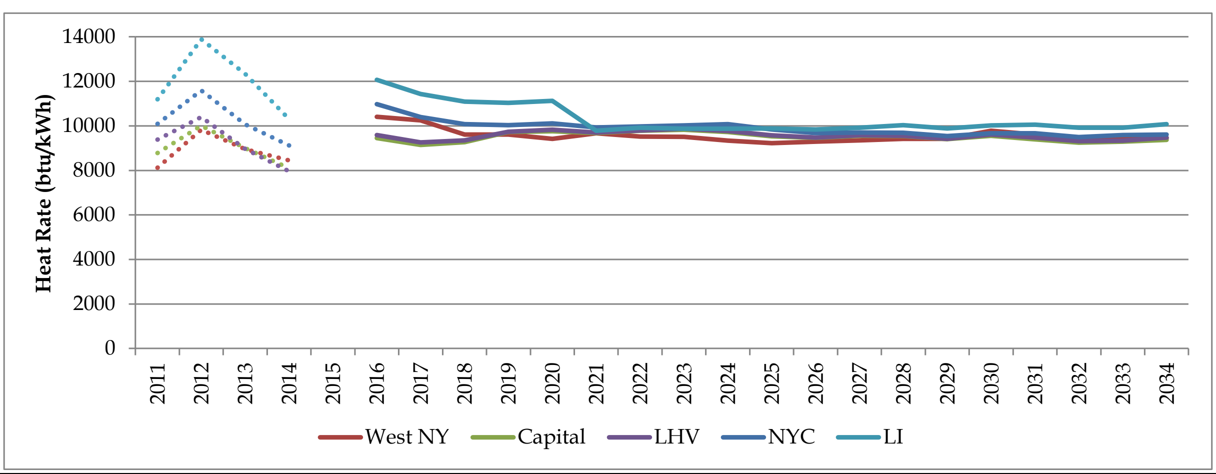
Marcellus Shale gas with pipeline expansion scenario



Henry Hub gas with pipeline expansion scenario



Marcellus Shale gas with persistent basis differential scenario



4.1.3 Costs of transmission congestion in the wholesale energy market

Annual congestion value on the C/E and UPNY/SENY interfaces, which drive the price separation between the western and eastern NY regions, is forecasted to decline by between 70% and 85% by 2030 as compared with the 2016-2017 levels in LEI's Base Case (the range of 70% to 85% is based on the varied gas price outlook - three scenarios were modeled in this study, as shown in Figure 28 below).

Under the *Henry Hub gas with pipeline expansion* and *Marcellus Shale gas with persistent basis differential* scenarios, congestion level for 2016-2017 on each of the interfaces is similar to recent historical levels as the natural gas price difference between western and eastern NY is similar to recent years. Congestion level for *Marcellus Shale gas with pipeline expansion* is more akin to the level seen in 2012 (as shown in section 2.2), which is consistent with the difference in western versus eastern NY natural gas prices under that scenario for the 2016-2017 period being similar to the difference in gas prices observed in 2012.

Figure 28 illustrates the forecasted congestion value[16] across the C/E and UPNY/SENY interfaces over the modeling horizon.

Under the *Marcellus Shale gas with pipeline expansion* scenario, congestion value on the C/E and UPNY/SENY interfaces is forecasted to be very low as compared to recent years. This result is directly attributable to the absence of a winter basis between natural gas prices in western versus eastern NY for this scenario, as is discussed further in section 5.3.2. Furthermore, the retirement of nuclear baseload generation western NY coupled with new generation that is scheduled to come online downstream of the C/E and UPNY/SENY interfaces (zones G through K) in the LEI Base Case will further reduce the congestion value over these interfaces starting in 2019.

Conversely, congestion value forecasted under the *Henry Hub gas with pipeline expansion* and *Marcellus Shale gas with persistent basis differential* natural gas pricing scenarios is expected to remain at the level seen in recent years and then decline sharply by 2019. The high congestion value apparent on C/E under these scenarios in the 2016-2018 timeframe is a consequence of the significant spread between western and eastern NY natural gas price levels during that period.

Congestion value over the C/E interface in the 2020-2030 timeframe hovers around $50 million annually under the *Henry Hub gas with pipeline expansion* scenario, while it is slightly higher under the *Marcellus Shale gas with persistent basis differential* scenario. This result is consistent with the slightly lower annual basis between western versus eastern NY natural gas prices observed in the former scenario as opposed to the latter, as discussed in section 4.1.1.

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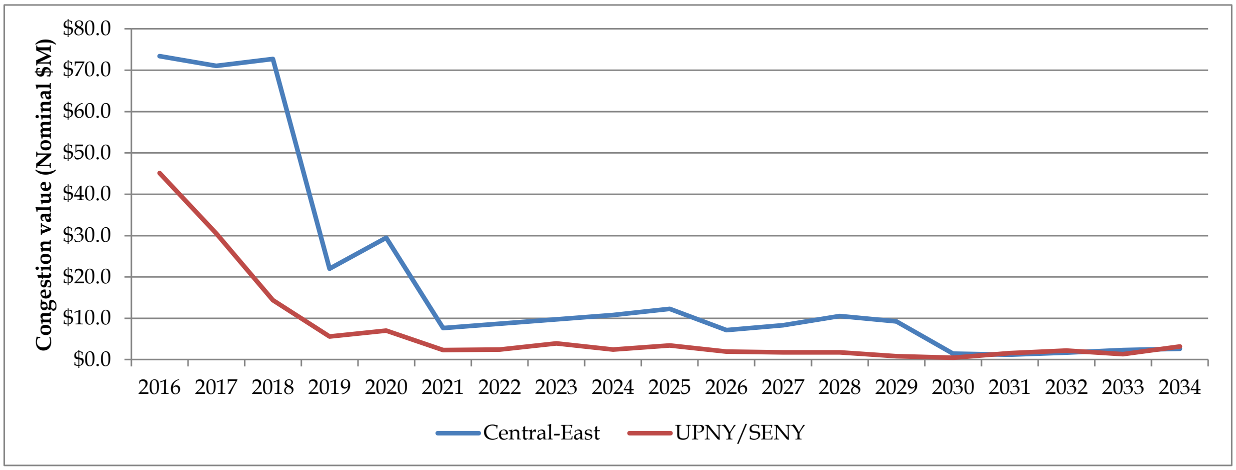
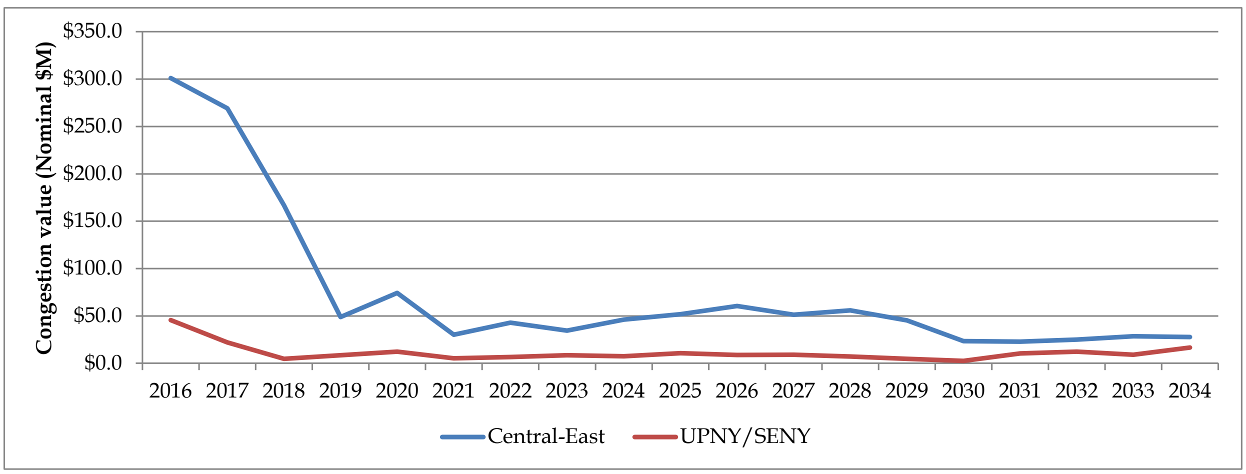
[16] Congestion value is defined as the sum, over all pricing intervals of a given year, of the difference in the congestion component of the LBMP between two zones times the energy flows between the two zones.

Figure 28. Forecasted congestion on the C/E and UPNY/SENY

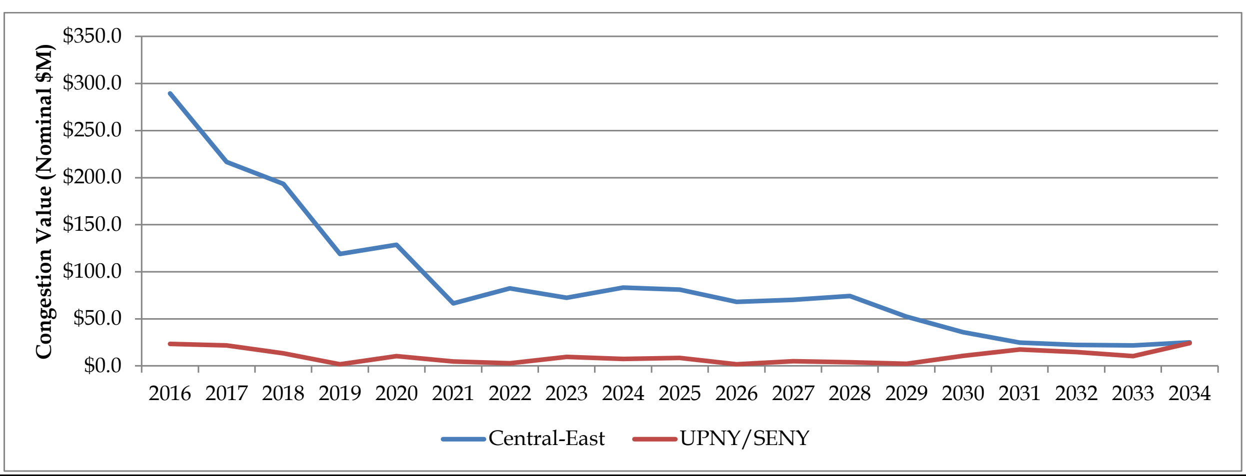
Marcellus Shale gas with pipeline expansion scenario



Henry Hub gas with pipeline expansion scenario



Marcellus Shale gas with persistent basis differential scenario



One noteworthy observation is that the main driver of the congestion value over C/E is the spread in natural gas prices between western and eastern NY, as opposed to the absolute level of the natural gas prices. While the *Henry Hub gas with pipeline expansion* scenario uses gas prices that are on average 30% higher than those under the *Marcellus Shale gas with persistent basis differential* scenario, the level of congestion value is actually lower. Absolute level of natural gas prices do however affect congestion to a certain level as the cost to redispatch generation does increase with gas prices.

Under all three natural gas pricing scenarios, congestion over the UPNY/SENY interface is forecasted to decrease over the 2016-2034 horizon as compared to historical levels in recent years. LEI attributes this lower level of congestion value to three factors:

- LEI relies on weather-normalized forecasts, which do not account for extreme weather which could cause significant variations in load. As shown in section 2.3.2, congestion over the UPNY/SENY interface is present mostly during the summer period during periods of very high demand;
- LEI does not take into account Thunder Storm Alerts, the consequence of which is a reduction in the UPNY/SENY transfer limit and the appearance of congestion. While TSAs are issued in real-time, virtual bidding in the DAM when traders anticipate a TSA will cause congestion to appear in day-ahead prices as well; and
- The overwhelming majority of new entry over the forecast horizon is expected to come online downstream of the UPNY/SENY interface (except for a new CCGT in zone F in 2031).

Section 5 of this report discusses how congestion over the C/E and UPNY/SENY interfaces impact the cost of electricity to consumers.

4.2 Capacity market projections

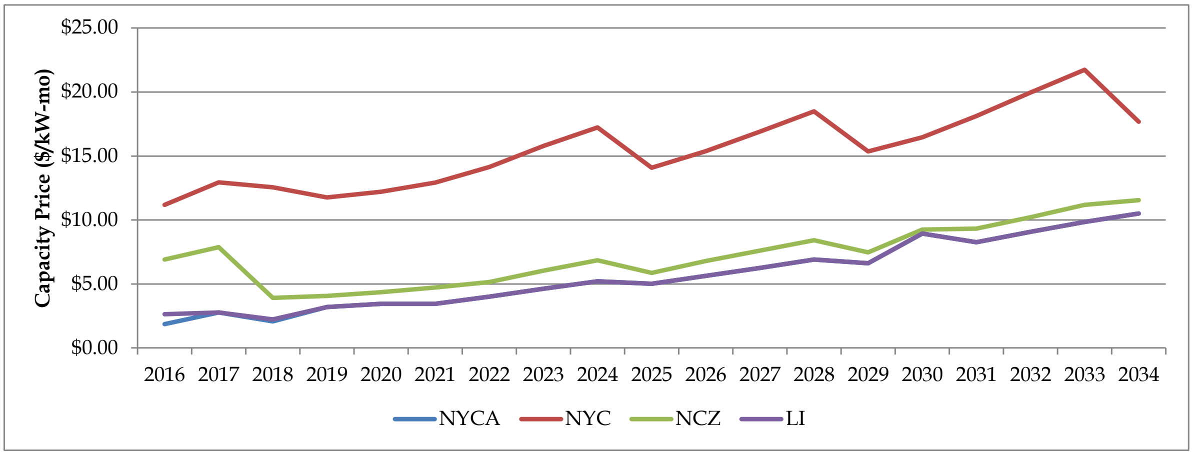
Capacity prices are very similar under all energy market price scenarios as the supply resources remain the same across all scenarios[17]. NYC prices generally remain much higher than other regions because of the higher reference point and relative difficulty of siting new generation in that part of the NYCA (for example, Buyer Side Mitigation rules prevent new entry from depressing capacity prices below a certain threshold and therefore limit when and how much new capacity is added in that locality). NYCA and LI capacity prices are forecasted to remain low initially then rise steadily as load grows and retirements occur.

Figure 29 presents the forecasted capacity prices for all regions over the 2016-2034 horizon under all three natural gas price scenarios. Section 5.2 of this report discusses how new transmission might affect the capacity prices and the resulting cost of capacity to consumers.

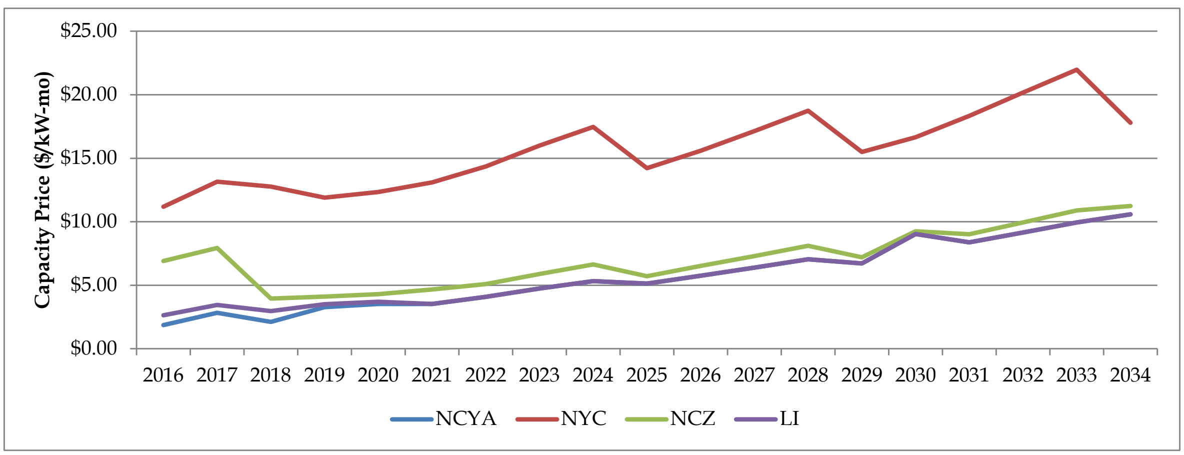
[17] LEI used the same supply resources (including retirements and new entry) for all 3 natural gas scenarios as the variation in revenues between the different scenarios is not sufficient to change the timing of retirements or new entry

Figure 29. Forecasted capacity prices

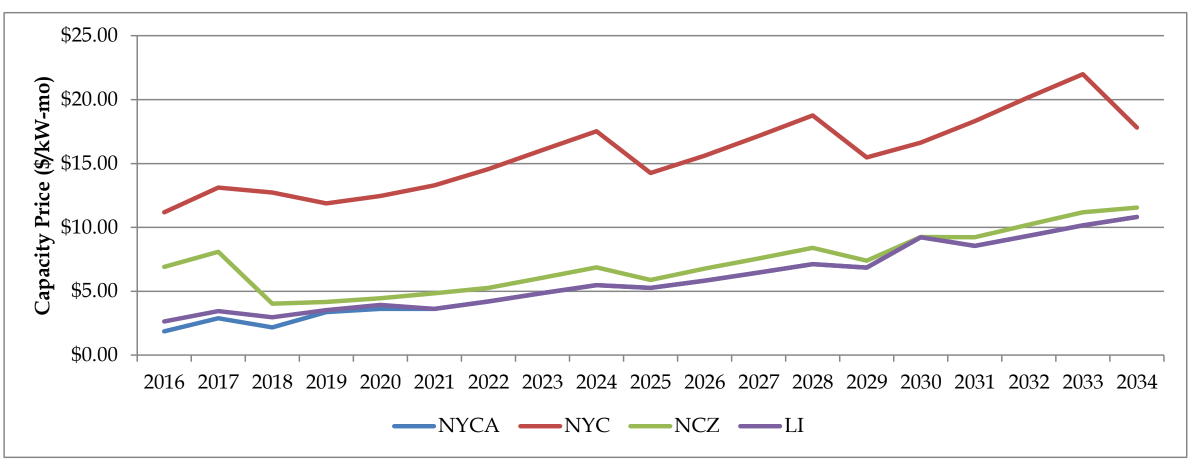
Marcellus Shale gas with pipeline expansion scenario



Henry Hub gas with pipeline expansion scenario



Marcellus Shale gas with persistent basis differential scenario



As discussed further in section 9.9, the impact of the different gas pricing scenarios is reflected in the Reference Point used to set the demand curve in the capacity spot auctions held on a monthly basis. A higher or lower reference point will steepen or flatten the demand curve. However, in these cases, the difference in the value of the reference point between the different natural gas pricing scenarios is not sufficient to significantly affect the capacity price forecast.

NYCA and LI capacity prices are forecasted to remain low initially as new entry come online in the NCZ, NYC and LI zones within the 2018-2021 timeframe. NYCA and LI prices then rise steadily as load grows, with the occasional new entry into NYC in 2025 and 2029, before rising sharply following the forecasted retirement of the Nine Mile Point 1 nuclear generator in 2030.

NCZ capacity prices are initially much higher than NYCA and LI prices, but the entry of the CPV Valley CCGT in 2018 greatly reduces the price spread between these regions. CPV Valley has such a large effect on NCZ prices because it has been exempt from Buyer-Side Mitigation ("BSM"). BSM is designed to prevent uneconomic new entry from depressing capacity prices in a particular region (NCZ or NYC), but CPV has successfully passed the NYSIO economic tests for new entries[18].

NYC capacity prices are forecasted to remain high over the 2016-2034 horizon. While the NYISO has crafted a Competitive Entry Exemption ("CEE") rule that allows new entry to be exempt from BSM if it does not have a contractual engagement with a "Non-Qualifying Entry Sponsor"[19], LEI assumes that new entry in the NYC capacity markets will not qualify under the CEE and therefore be subject to BSM.

New entry and other generators within NYC receive the clearing price from the local region's auction, but since NYC is nested within the NCZ zone, the new capacity in NYC also counts towards the NCZ capacity requirement. This has the effect of keeping NCZ prices only slightly above NYCA prices.

As explained in section 9.3, LEI includes generic new capacity in its energy and capacity models when the new generator is expected to at least recover its costs. Demand-side resources are already included in the load forecast by NYISO. The NYISO ICAP and UCAP reference points are based on the net Cost of New Entry ("net CONE"), which represents the capacity revenue requirement of the lowest-priced new capacity resource that could enter the market. That new entry is typically a gas turbine.

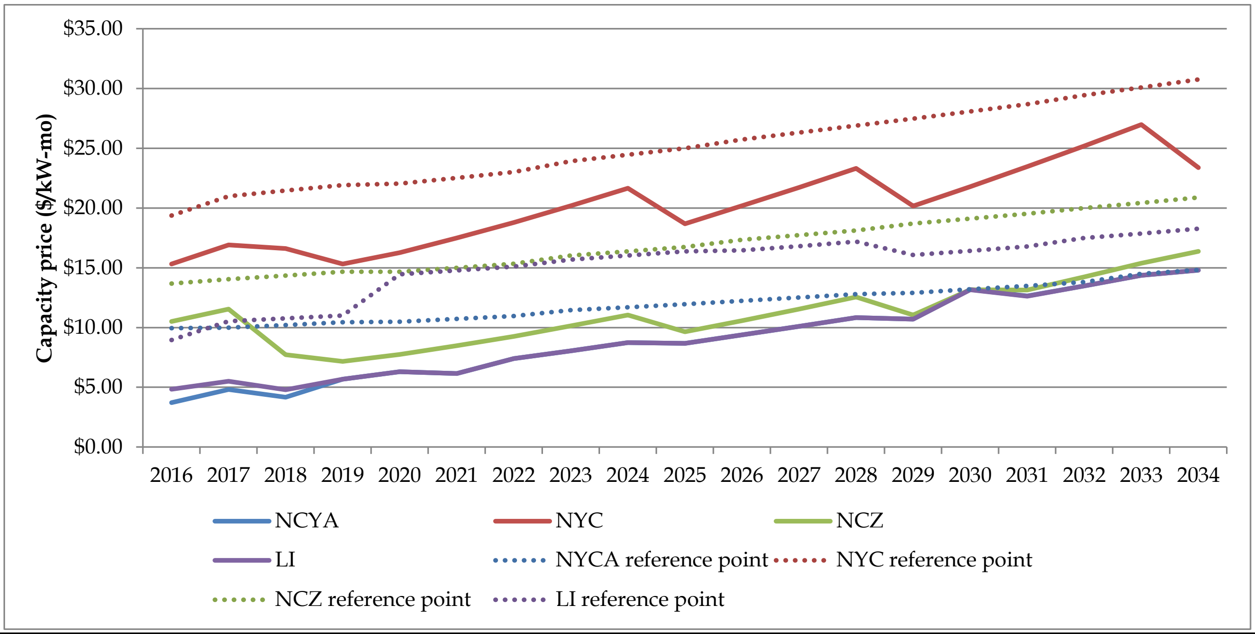
While LEI assumes that new entrants are CCGTs, the demand curve Reference Point is still a good benchmark to determine when a new entrant would be expected to be able to recover its

[18]http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Buyer_Side_Mitigation/Class_Year_2011/MMU%20Report%20re%20MET%20for%20CPV_Final_3-7-14.pdf

[19] A Transmission Owner, a Public Power Entity, or any other entity with a Transmission District in the NYCA or an agency or instrumentality of New York State or a political subdivision thereof

costs. Figure 30 illustrates LEI's forecast of summer capacity prices in the different regions (using the *Henry Hub with pipeline expansion* scenario as an example). The dotted lines represent the UCAP reference point applicable to each year's demand curve. As can be seen from the figure, new entry (observable from the sharp decline in capacity prices) is forecasted to come online as the summer prices approach the Reference Point.

Figure 30. Forecasted summer capacity prices compared to the region-specific UCAP reference points



5 Discussion of the implications of congestion costs

5.1 Relating energy market congestion to costs for consumers

While congestion value represents a good metric for analyzing the trends in congestion in the energy markets, it does not relate strictly to productivity efficiency gains or cost savings to consumers from new transmission if there is no specific modeling of the market with and without the proposed transmission addition. That said, it is possible to hypothesize whether the absolute level of congestion (which is part of production costs) is sufficiently high as to generate benefits once a transmission project is added into the energy modeling.

While generators are remunerated from the price at their generator bus, electricity consumers pay a zonal price which is the weighted average of all generator buses within the zone. As a consequence, if congestion is reduced for instance through increased transmission capacity into the constrained zone, the resulting more efficient dispatch of resources will result in a lower price to consumers.

In order to illustrate the effects of congestion relief, LEI prepared a simple example using the forecasted zonal energy usage from the 2015 Gold Book. Figure 31 illustrates the example representing a hypothetical congestion relief scenario where the average annual LBMP in eastern NY is reduced by $1/MWh following an increase in transmission capacity and subsequent reduction in congestion in the energy markets

Figure 31. Hypothetical congestion cost scenario

NYCA region	2016 Annual energy (GWh)	Congestion relief ($/MWh)	Total cost savings (M$)
Eastern NY	105,509	$1.00	$106

As shown in the above scenario, a reduction of $1/MWh through congestion savings for the eastern NY load would result in cost reductions of $106 million annually, subject to variation of the actual load.

Congestion relief can be caused by any one of several factors discussed throughout this report, including:

- a change in natural gas prices;
- a change in the NYCA load pattern;
- a change in the NYCA supply mix;
- new transmission; or
- any combination of the previously listed factors.

While prices may increase in regions historically upstream of congested interfaces following congestion relief through additional transmission, higher prices could also have beneficial consequences. In the context of the NYCA, increased western NY prices could allow currently uneconomic carbon-neutral resources such as nuclear generators to remain operating. It might also allow for more expensive renewable resources located in western NY to recover a greater percentage of their cost through the energy markets and decrease the need for out-of-market subsidies.

5.2 Relating capacity market congestion to costs for consumers

Congestion is reflected in the capacity market through the Locational Capacity Requirements ("LCR"), which represent a percentage of the capacity requirement that must be procured from capacity suppliers located within the same locality as the load. The LCR ensures that, should a transmission contingency occur which would reduce transmission capacity into a locality, there is sufficient local generation available to avoid curtailing load. Therefore, the more constrained is a transmission interface into a locality, the higher is the LCR and need for local capacity supply. For instance, the NCZ LCR is 90.5% and the NYC LCR is 93.5%, while the LI LCR is 103.5%. These values are consistent with successively higher requirements for local generation the further a load center is from most of the generation resources within the state.

In a similar fashion to the discussion in section 5.1, Figure 32 defines a hypothetical reference scenario illustrating the cost of capacity for load from zones G,H, and I (also known as the the NCZ (excluding NYC)). This example assumes that all capacity was procured at a price equal to the June 2015 spot auction, and the resulting costs are shown for the month of June 2015 and extrapolated over the entire summer 2015 period (for illustration purposes).

Figure 32. Cost of capacity to load in zones G, H, I (illustrative example)

	GHI Peak Load (MW)	Requirement %	Derating Factor %	ICAP MW requirement	UCAP MW requirement
Global requirement	**4410.6**	**117.0%**	**8.54%**	**5160.4**	**4719.7**
Locational requirement	4410.6	90.5%	5.77%	3991.6	3761.3
NYCA requirement					958.4

	Quantity (MW)	price ($/kW-mo)	Cost ($M)
UCAP purchased in NCZ	3761.3	$10.56	$39.7
UCAP purchased in NYCA	958.4	$4.88	$4.7

	Total Excess purchased (MW)	Ratio of GHI load	Excess allocated to GHI LSEs	price ($/kW-mo)	Cost ($M)
Excess purchased in NCZ	413.6	27.0%	111.6	$10.56	$1.2
Excess purchased in NYCA	2178.1	13.1%	286.2	$4.88	$1.4

Cost to load ($M)	Monthly ($M)	Period ($M)
UCAP purchased in NCZ	$39.7	$238.3
UCAP purchased in NYCA	$4.7	$28.1
Excess purchased in NCZ	$1.2	$7.1
Excess purchased in NYCA	$1.4	$8.4
Total	$47.0	$281.8

The global ICAP requirement of LSEs serving load in the NCZ (zones G, H, and I but excluding NYC) is equivalent to the region peak load (4,411 MW) plus the NYCA reserve requirement of 17%, which amounts to 5,160 MW in ICAP terms or 4,720 MW in UCAP terms, when the NYCA derating factor (8.54%) is applied[20]. However, from that global ICAP requirement, a portion must be procured from resources located within the NCZ: specifically, 90.5% or 3,992 MW in ICAP or 3,761 MW in UCAP (when the NCZ derating factor (5.77%) is applied). The difference between the global UCAP requirement (4,720 MW) and the locational requirement (3,761 MW) does not need to be purchased from resources located in the NCZ, and that figure is 958 MW of UCAP. So 958 MW of UCAP can be purchased from any resource participating in the NYCA auctions.

Using prices from the June 2015 spot auction[21], LSEs had to procure 3,761 MW at the NCZ price of $10.56/kW-mo for a total cost of $39.7 million. Furthermore, those same LSEs procured 958 MW at the NYCA price of $4.88/kW-mo for a total of $4.7 million.

In addition to procuring the UCAP minimum requirement, NCZ LSEs must also purchase their share of the total capacity cleared in excess of the minimum requirement through the NCZ and NYCA spot auction.[22]

For the June 2015 spot auctions, the excess capacity cleared was 414 MW and 2,178 MW, respectively, in the NCZ and NYCA.[23] The zone G, H, and I UCAP requirement represents 27% and 13% of the total NCZ and NYCA UCAP requirements, respectively .[24] As a result, LSEs in zones G, H, and I had to purchase 112 MW of excess capacity (27% of 414 MW) at the NCZ price of $10.56/kW-mo for a total of $1.2 million. Similarly, those same LSEs had to purchase 286 MW (13% of 2,178 MW) at the NYCA price of $4.88/kW-mo for a total of $1.4 million.

The resulting total cost of capacity to load located in zones G, H, and I is $47 million for the month of June 2015, and represents around $282.0 million, if extrapolated over the summer period under the current constrained conditions. As explained further below and demonstrated

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[20] NYISO ICAP & UCAP calculations. Web. <http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_detail.do>

[21] NYISO ICAP Market Report - June 2015. Web. <http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/Monthly%20Reports/Monthly%20UCAP%20Reports/2015/ICAP%20Market%20Report%20-%20June%202015.xls>

[22] Because of the sloped demand curve construct, ICAP spot auctions can clear more or less than the minimum UCAP requirement. When the amount of capacity purchased is above the minimum requirements (which causes the clearing price to be below the reference point as defined in section 9.10), the cost of UCAP purchased in excess of the minimum requirement is allocated to LSEs according to their share of the regional peak load.

[23] NYISO ICAP Market Report - June 2015. Web. <http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/Monthly%20Reports/Monthly%20UCAP%20Reports/2015/ICAP%20Market%20Report%20-%20June%202015.xls>

[24] *Ibid*

using a hypothetical example, a decrease in the LCR through additional transmission capacity into the NCZ could materially lower the costs of capacity for customers located in that zone.

Several factors can influence the locational capacity costs in NYISO capacity market, such as:

- local load forecast;
- generating units' forced outage rates;
- new supply or retirements
- performance factor of Special Case Resources; and
- transmission capability changes.

The first four factors can influence the LCR and also have an effect on capacity requirement or supply, which in turn affects the cost of capacity to consumers. However, transmission capability changes (the fifth factor in the list above), all else being equal, can have a direct effect on the LCR and result in lower costs to consumers. For instance, new transmission capability into the LHV (zones G, H and I) would allow more energy to flow from western NY during peak load conditions and therefore lower the need to rely on local capacity.

Figure 33 illustrates the impact of a reduced LCR on the cost of capacity to load. The revised example assumes that hypothetical new transmission capacity into LHV reduces the locational minimum installed requirement in the NCZ by 500MW, which represents a LCR of 87.4% for the NCZ (as opposed to the current 90.5%).

Figure 33. Cost of capacity to load in zones G, H, and I, assuming a lowered LCR

	GHI Peak Load (MW)	Requirement %	Derating Factor %	ICAP MW requirement	UCAP MW requirement
Global requirement	**4410.6**	**117.0%**	**8.54%**	**5160.4**	**4719.7**
Locational requirement	4410.6	87.4%	5.77%	3856.6	3634.1
NYCA requirement					1085.6

	Quantity (MW)	price ($/kW-mo)	Cost ($M)
UCAP purchased in NCZ	3634.1	$7.40	$26.9
UCAP purchased in NYCA	1085.6	$4.88	$5.3

	Total Excess purchased (MW)	Ratio of GHI load	Excess allocated to GHI LSEs	price ($/kW-mo)	Cost ($M)
Excess purchased in NCZ	884.7	27.0%	238.8	$7.40	$1.8
Excess purchased in NYCA	2178.1	13.1%	286.2	$4.88	$1.4

Cost to load ($M)	Monthly ($M)	Period ($M)
UCAP purchased in NCZ	$26.9	$161.4
UCAP purchased in NYCA	$5.3	$31.8
Excess purchased in NCZ	$1.8	$10.6
Excess purchased in NYCA	$1.4	$8.4
Total	$35.4	$212.1

In this scenario, the global ICAP requirement does not change from the reference case but the ratio of capacity purchased at the NCZ price as compared to the NYCA price is lower. The global ICAP requirement of LSEs serving load in the NCZ (zones G, H, and I, but excluding NYC) is still 4,720 MW in UCAP, as in the previous example. However, the portion that must be procured from resources located within the NCZ is now 87.4% of the peak load, representing 3,857 MW in ICAP or 3,634 MW in UCAP when the NCZ derating factor (5.77%) is applied. The difference between the global UCAP requirement (4,720 MW) and the locational requirement (3,634 MW to be purchased from resources located in the NCZ) represents 1,086 MW of UCAP that can be purchased from any resource participating in the NYCA auctions (therefore at a lower price as compared to the NCZ capacity price).

In addition with a lower LCR, the resulting spot auction capacity market clearing price also decreases. While the supply of capacity remains unchanged, the demand curve is shifted left, because the UCAP requirement is now 3,634 MW instead of 3,761 MW (as in the previous example). Although the maximum clearing price and reference price values on the demand curve are not changed, the supply curve intersects the demand curve at a lower point down the demand curve. As a result, the revised clearing price for the NCZ June 2015 spot auction is now $7.40/kW-mo. The NYCA clearing price is not affected as the global, NYCA-wide capacity requirement has not changed.

Under this revised example, LSEs need to procure 3,634 MW at the NCZ price of $7.40/kW-mo for a total cost of $26.9 million. Furthermore, those same LSEs procure 1,086 MW at the NYCA price of $4.88/kW-mo for a total of $5.3 million.

Once again, in addition to procuring the UCAP minimum requirement, NCZ LSEs must also purchase their share of the total capacity cleared in excess of the minimum requirement through the NCZ and NYCA spot auction. In this revised example, the excess capacity cleared is respectively 885 MW and 2,178 MW in the NCZ and NYCA. Knowing that the zones G, H and I UCAP requirement represents respectively 27% and 13% of the total NCZ and NYCA UCAP requirement, LSEs in zones , GH and I had to purchase 239 MW of excess capacity (27% of 885 MW) at the NCZ price of $7.40/kW-mo for a total of $1.8 million. Similarly, those same LSEs had to purchase 286 MW (13% of 2178 MW) at the NYCA price of $4.88/kW-mo for a total of $1.4 million.

In summary, under this lower LCR example, the resulting total cost of capacity to load located in zones G, H, and I is $35 million for the month of June 2015, and represents around $212.0 million if extrapolated over the summer period under the current constrained conditions.

The end result of this hypothetical lower LCR scenario is a decrease in capacity costs of $11.6 million ($35.4 million versus $47.0 million in the first instance) for the month of June 2015, or $69.7 million ($212.1 million versus $281.8 million) if extrapolated over the summer capability period and close to $140 million annually.

The hypothetical savings to consumers illustrated in this scenario do not take into account the costs of the transmission upgrades that were assumed. When costs of the transmission expansion are borne by consumers, at the minimum, a cost-benefit analysis needs to be performed and the costs of transmission upgrades (which will factor into the transmission rates paid by consumers) must be weighed against the benefits (e.g., lower costs of capacity and energy, if applicable).

5.3 Qualitative analysis of transmission congestion drivers

The energy and capacity results presented in previous sections are representative of the set of assumptions selected by LEI in its modeling of the NYISO markets. However, a number of factors that can influence congestion over the key NYCA internal interfaces are uncertain, but critical to the outcomes. LEI was able to test three different gas price scenarios under a single demand and supply outlook, representing normal conditions with rational, "just in time" entry. The scope of work for the simulation-based modeling did not afford the opportunity for LEI to test other possible combinations of supply and demand. Therefore, in this section of the Report, LEI considers the impact of such drivers on market outcomes and forecast congestion qualitatively.

As a summary, Figure 34 presents a list of the major drivers of congestion within the NYCA and their notional (directional) impact on congestion, depending on the change from LEI's Base Case assumptions.

Figure 34. Congestion drivers and their impact on NYCA congestion value

Congestion Driver	Increased Congestion	Decreased Congestion
Increased demand	↑	
Decreased demand		↓
Increased natural gas basis differential between western and eastern NY	↑	
Increased natural gas prices	↑	
Generation retirement in western NY		↓
Generation retirement in eastern NY	↑	
New Generation in western NY	↑	
New generationin eastern NY		↓
New Transmission capacity		↓

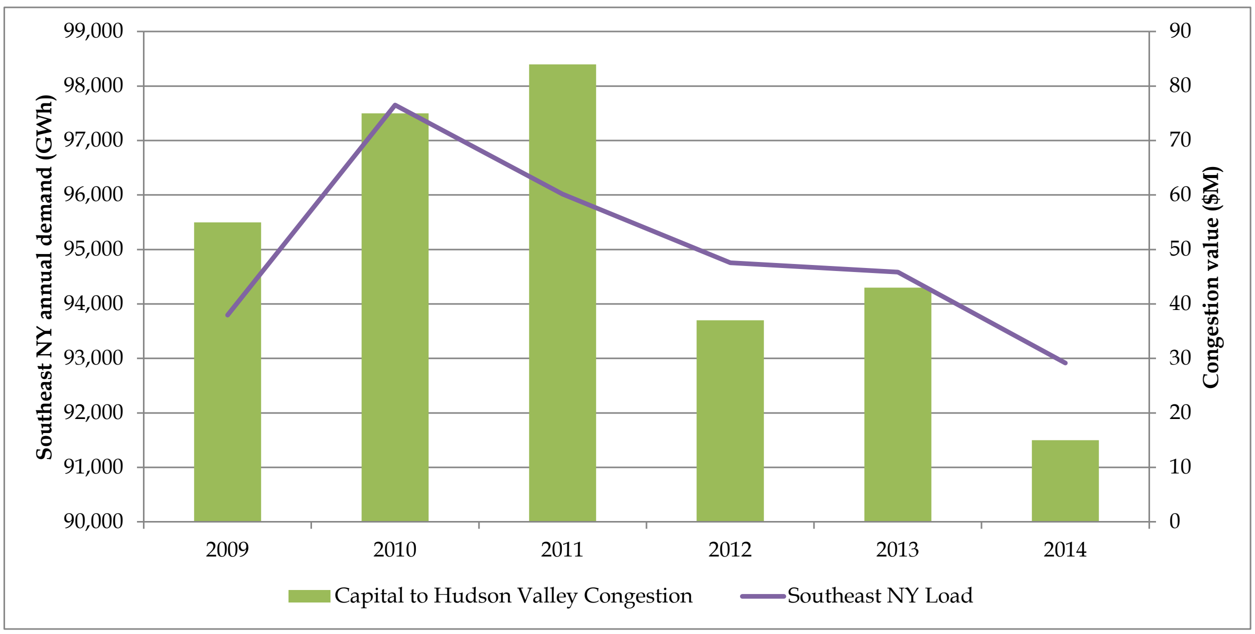
5.3.1 Demand

Demand is an important driver of congestion on electricity transmission networks. To meet the increase in load, system operators need to dispatch additional generation which is not always located in a region close to the load. If transmission lines between the regions are not sufficient to allow the energy to flow from the next cheapest generator available to the load, then a more expensive generator located near the load needs to be dispatched. This redispatch leads to price separation between different zones within the NYCA and is more likely as load grows.

In a state like NY where a significant portion of the generation capacity is located away from the larger load zones of NYC and LI, a higher demand would tend to increase flow on the transmission interfaces and potentially cause congestion to rise. That effect is particularly apparent on the UPNY/SENY interface.

Conversely, if demand is lower than forecast due to lower economic activity or additional success with EE and DG efforts in the state (and especially in the LHV, NYC and LI regions), then congestion across NYCA would be lower.

Figure 35. Historical UPNY/SENY congestion value (DAM) relationship to Southeast NY load



Source: NYISO 2015 Gold Book, Potomac Economics, State of the Market Report 2010-2014

Figure 35 illustrates the trend in congestion on the UPNY/SENY interface and how it relates to the load in Southeast NY (which includes load from zones G through K). While load is certainly not the only factor that can affect congestion on the UPNY/SENY interface, there is a correlation between historical periods of higher demand and the level of congestion observed on that interface.

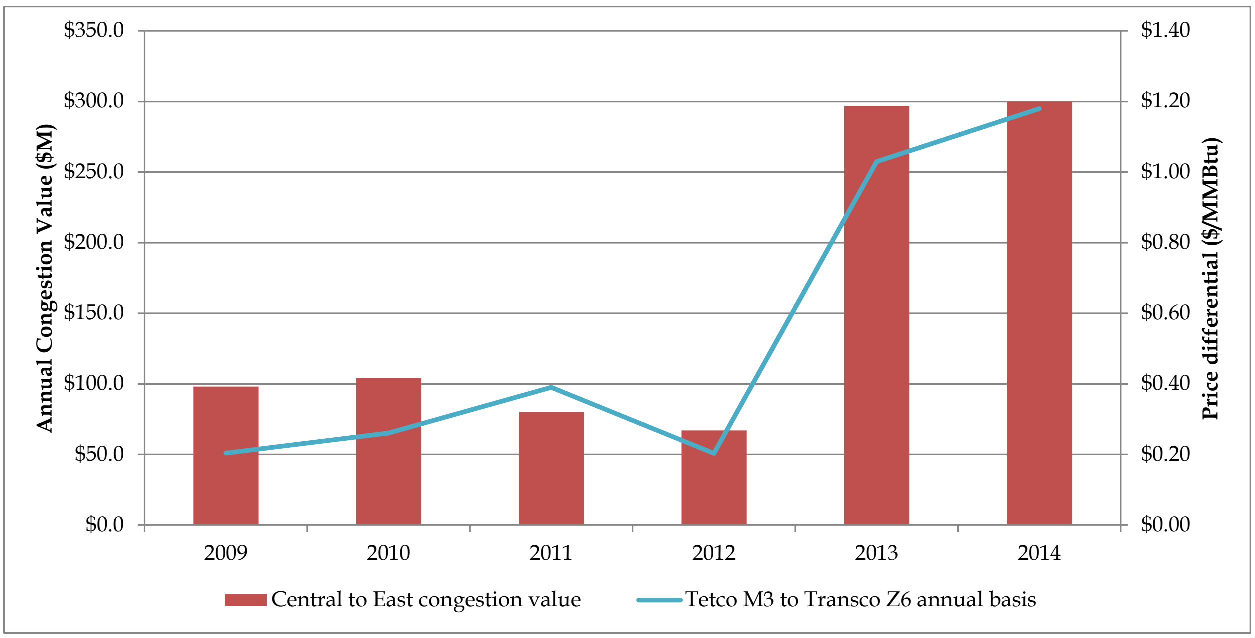
A compounding factor for the increase in congestion value as load increases is that the supply offer curve is not linear. In high demand scenarios, as transmission interfaces limit energy flows, local peaking units with very high variable operation cost may need to be committed and dispatched in the constrained importing area, leading to a significant disparity between zonal prices and increased congestion.

5.3.2 Natural gas prices

As discussed throughout earlier sections of this report, natural gas prices have a significant effect on the level of congestion within the NYCA.

Figure 36 illustrates the historical annual value of congestion between western NY and the Capital zone (Central to East). Superimposed on the chart as a blue line is the historical annual basis between the Tetco M3 pricing hub and the Transco Z6 (NY) pricing hub. As observed in this figure, the relationship between natural gas price differential and congestion is strong: as gas price differences rise, so does the value of congestion (in the day ahead energy market).

Figure 36. Historical C/E congestion value (DAM) relationship to western/eastern NY natural gas price differential

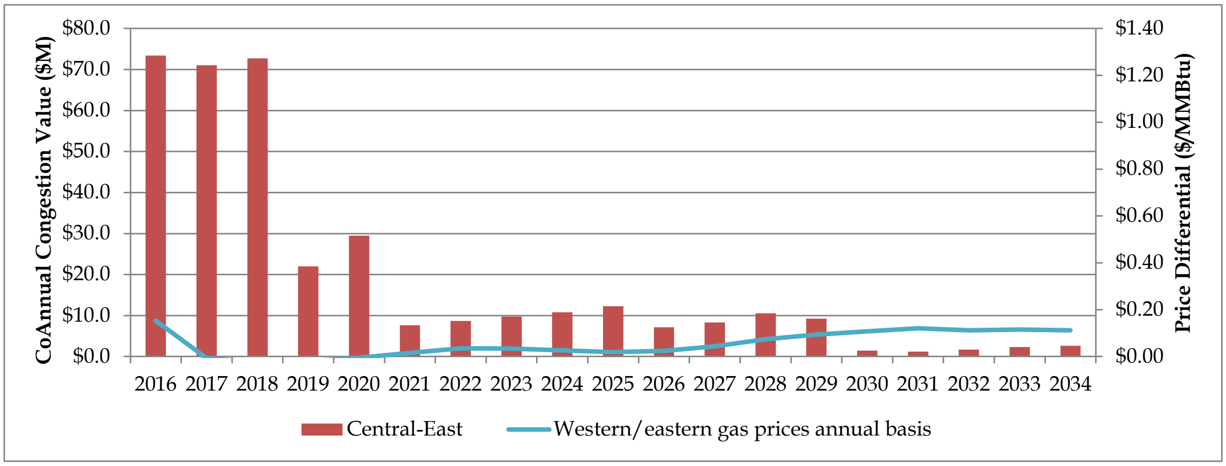


Source: Potomac Economics, State of the Market Report 2010-2014; SNL

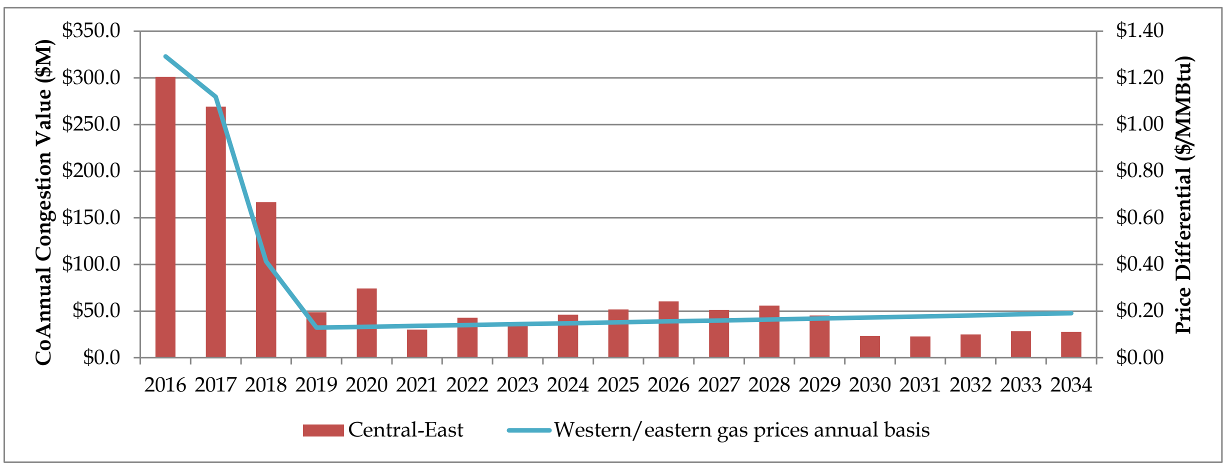
Figure 37 illustrates the same relationship as the previous figure but this time using LEI's modeled outcomes over the forecast horizon and for emphasis, showing all three LEI natural gas pricing scenarios.

Figure 37. Forecasted C/E congestion value relationship to western/eastern NY natural gas price differential

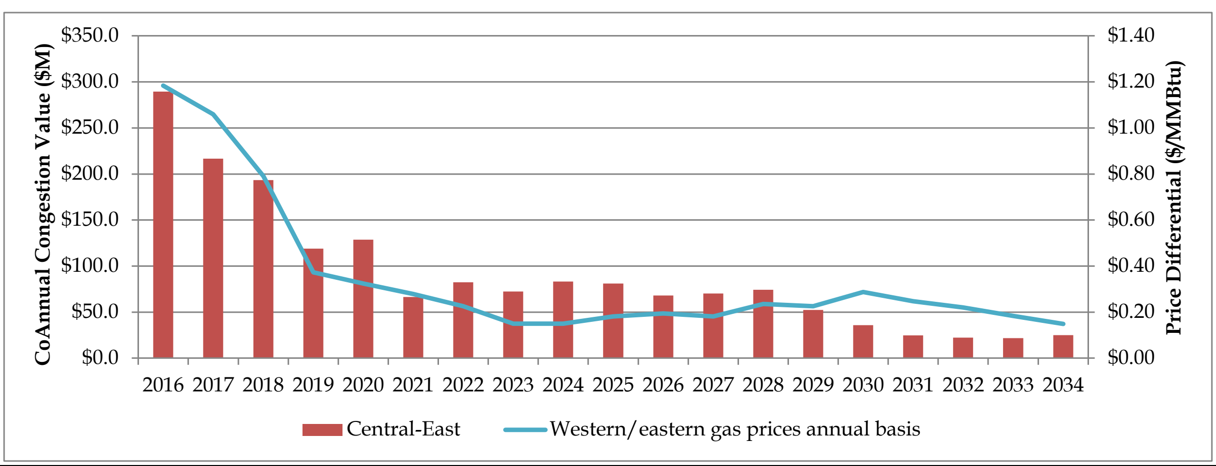
Marcellus Shale gas with pipeline expansion scenario



Henry Hub gas with pipeline expansion scenario



Marcellus Shale gas with persistent basis differential scenario



While the relationship between C/E congestion value and the basis between western/eastern natural gas prices is readily apparent in these figures, the result from the *Marcellus Shale gas with pipeline expansion* scenario is interesting.

The *Marcellus Shale gas with pipeline expansion* scenario exhibits almost no basis in gas prices between western versus eastern NY from 2016 onward. However there is still congestion apparent over the C/E interface from 2016 to 2018. The takeaway from this figure is that while gas price differential is indeed a major driver for congestion over the C/E interface, there is still a certain level of congestion inherent to the NY supply mix. As discussed in section 5.3.3 below, the western NY region is dominated by hydro and nuclear generation as well as low priced imports, while eastern NY is heavily dependent on gas-fired resources. However, following the retirement of the Ginna nuclear power plant in western NY in 2019 as well as the entry of new efficient generation in eastern NY in 2018-2019 (CPV Valley, Berrians I/II/III[25]), congestion over the C/E interface is greatly reduced as there is less demand for the western NY generation given the addition of new resources closer to load and downstream of the binding transmission interface.

5.3.3 Changes in the supply mix

As briefly introduced in section 5.3.2, generation supply mix has a significant effect on congestion across the various transmission interfaces.

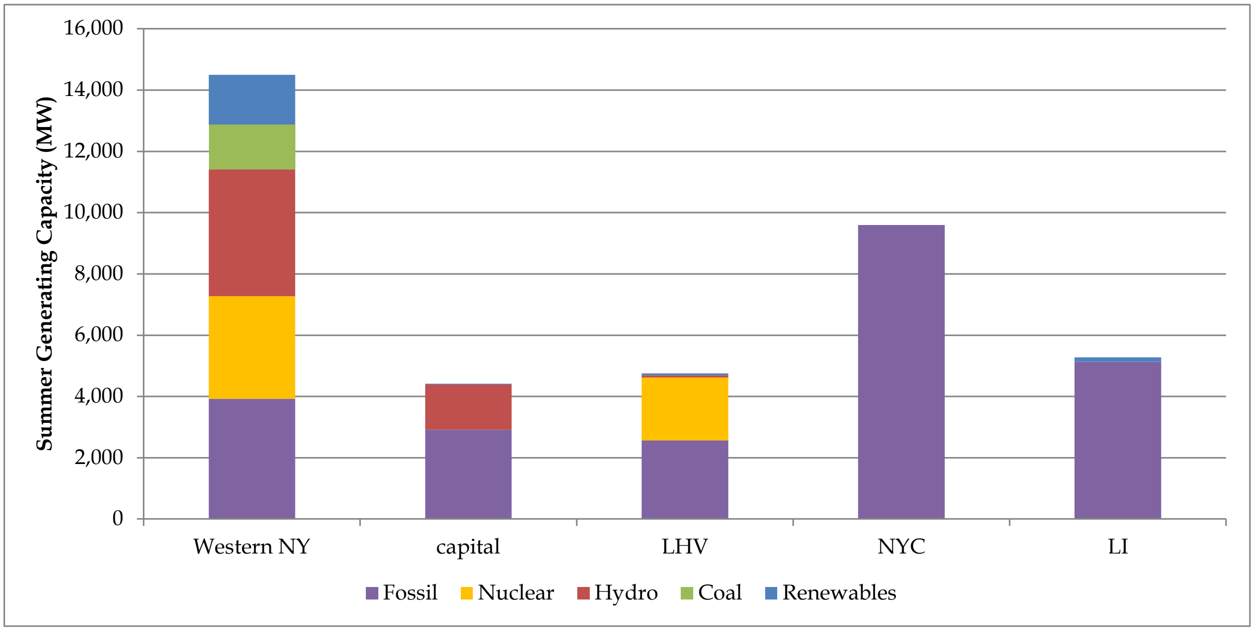
Figure 38 demonstrates that most of NYCA's installed generating capacity is located in western NY. Furthermore, lower-cost generators are typically also located in western NY. Of significance are 2 large NYPA-owned hydro facilities, 4 nuclear power plants, as well as wind and smaller run of the river resources. Furthermore, relatively low-priced imports from Ontario and Québec are also injecting into and impacting prices in the western NY region. Conversely, the supply mix in eastern NY is composed of often older and costlier gas- and oil-fired steam turbines or gas turbines.

As a result, energy flows largely from western NY toward eastern NY and creates congestion when interfaces such as C/E or UPNY/SENY reach their transmission limit.

However, LEI forecasts the retirement of baseload generation in western NY, notably the Ginna nuclear power plant in 2019. Furthermore, new efficient generation is expected to come online downstream of current transmission constraints as shown in section 9.3. The net effect is a reduction in flows from western towards eastern NY as western NY generators retire, load growth in western NY absorbs more of the local generation and new efficient gas-fired generation comes online in the eastern NY regions.

[25] See note 12 on page 37

Figure 38. Summer capacity fuel mix by region



Source: 2015 Gold Book

5.3.4 New Transmission

As discussed in section 5.3.3, most of the lower-priced generation is located in western NY while the load zones are in eastern NY. Therefore, the construction of new transmission capacity between western versus eastern NY would allow more energy to flow, thereby reducing the number of hours when the transmission constraints are binding. The result is a decreased congestion value over these interfaces. A project that increases transmission capacity between western and eastern NY would also lessen the impact of price differentials in locational natural gas prices, as more energy from the lower-priced western NY resources could be delivered to the load centers in eastern NY.

An increase in transmission capacity (whether upgrades to the AC transmission network or new DC projects bringing energy and capacity to the LHV, NYC or LI regions) could also allow new generation to be located in western NY without incurring the risk of lower energy prices because of congestion. As transmission constraints are reduced, the prices between different regions tend to converge (although not necessarily to the midpoint between the prices when congestion was present).

New transmission can also reduce losses between transmission zones. As the energy flows are spread over more conductors, electrical losses fall, too. Since the NYISO accounts for losses within the LBMP, a decrease in losses leads to further convergence of prices between the different regions.

Higher prices in western NY could encourage some of the older, carbon-neutral generation (such as nuclear plants) to remain online as their economic outlook would look better.

Furthermore, additional transmission capacity into eastern NY could facilitate the build out of new renewable generation as the energy and capacity from these generators could now be delivered to the load zones. The renewable generators benefiting from increased prices in the western region would also require lower out-of-market revenues to be economic.

Another impact of new transmission is the reduction in the LCR of the NCZ, NYC and LI capacity zones, which could lead to lower prices and also price convergence for the localities with NYCA pricing. The LCR currently ensures that, should a transmission contingency occur which would reduce transmission capacity into a locality, there is sufficient local generation available to avoid curtailing load. An increase in transmission capacity translates into a decreasing need for local generation. As the LCR decreases, the capacity requirement decreases also which puts downward pressure on local capacity prices until they are equal to the NYCA price.

Since capacity zones are nested within one another, a decrease in capacity prices for a particular zone does not raise the price in another zone. The results are net lower capacity costs for the ratepayers.

However, in the case of new transmission infrastructure (and to the extent that it is rolled into network service rates borne by consumers), care must be taken to consider the costs of such upgrades (increased transmission rates) along with the benefits.

5.3.5 Discussion on the likelihood of congestion drivers differing from LEI's base case assumptions

The likelihood of directional changes in drivers (for example, demand being lower versus demand being higher) is not always the same. The asymmetry arises in part because of the assumption that LEI has taken in the Base Case.

As discussed previously, demand is an important driver of congestion. LEI relies on the NYISO 10 year load forecast, which integrates Energy Efficiency and Distributed Generation as a result of programs such as Reforming the Energy Vision ("REV") or NY Sun. The effect from these programs is to reduce the net demand, such that the energy usage over the next 10 years is forecasted by the NYISO to be relatively flat and even decline for the initial years. However, should these programs prove less effective than forecasted by the NYISO, the resulting energy usage and peak load could be higher than anticipated, resulting in congestion which is higher than predicted over the C/E and UPNY/SENY interfaces, all else being equal. However, if the demand is sufficiently higher, then that higher demand will motivate new entry through the capacity market. If the new entry is in relatively similar locations as to the modeled new entry in LEI's base case, it is likely that this incremental supply would neutralize the increase in congestion.

Furthermore, the NYISO load forecast uses normalized weather conditions to evaluate the future demand. As a result, should summer temperatures prove warmer than average, the resulting increase in load could also lead to increased congestion as compared to LEI's base case forecast.

Natural gas prices, both the absolute level of prices and the locational difference in delivered gas prices within the state, have also been shown to play a crucial role in the amount of congestion over the C/E and UPNY/SENY interfaces. In all three natural gas scenarios, LEI relies on forecasts which represent the expected gas prices under normal weather conditions. However, winters with temperatures colder than usual will drive the natural gas prices higher and cause increased price separation between eastern NY and western NY, resulting in congestion across the C/E and UPNY/SENY interfaces which is higher than LEI's base case forecast. Similarly, if the new pipeline capacity assumed to be built over time under the *Marcellus Shale gas with pipeline expansion* and *Henry Hub gas with pipeline expansion* scenarios is delayed, the locational differences in prices might continue longer than anticipated, delaying LEI's forecast of a reduction in congestion across the C/E and UPNY/SENY interfaces and thereby catalyzing higher congestion costs than predicted under LEI's base case.

New electricity supply sources in key regions of the NYCA such as the LHV, NYC or LI play a key role in decreasing congestion across the constrained transmission interfaces. While LEI assumes a perfect competitive landscape where new entry comes online just in time when it is economic to do so, it is entirely possible that these new projects might be delayed. Since most new entry in LEI's base case is located in the LHV, NYC or LI regions, such delays would cause higher congestion values across the C/E and UPNY/SENY interfaces. Unforeseen retirements of resources in these regions would also have a similar effect on congestion. Conversely, it is unlikely that more resources than forecasted would come online in these regions resulting in an overbuild/oversupply situation. Although overbuild in eastern NY region is effectively prohibited by the buyer side mitigation, if it did occur, it would decrease congestion.

Finally, several unforeseeable events such as long-term outages of key transmission links, long-term outages of generators or weather-related events such as the number of TSAs all have a bullish effect on congestion across the major NYISO transmission interfaces.

While three different natural gas pricing scenarios were modeled, LEI did not have the occasion to perform sensitivity analyses on other important congestion drivers such as supply or load. Nonetheless, it is important to recognize that there is uncertainty surrounding these drivers' values for the next twenty years. Furthermore, as discussed above, there is a natural tendency for potential changes in these drivers (vis-a-vis LEI's Base Case assumptions) to increase the disparity in market prices across NYCA and therefore move market outcomes and forecast congestion away from the Base Case results presented in this Report.

6 Conclusion

LEI has presented the results from its forward-looking market study of the energy and capacity prices based on its Base Case outlook over the 2016-2034 horizon for the New York wholesale electricity market. This outlook allowed LEI to assess the magnitude of congestion in the energy markets over the C/E interface, which separates western and eastern NY, and the UPNY/SENY interface which limits flows into the LHV under certain circumstances. LEI also examined the capacity market-related congestion based on capacity price differences that arise between the NYCA zone and LHV (also known as NCZ).

The results are based on weather normalized load data, NYISO's load projections, and rational, economic investment that is timed to the modeled outcome. In recognition of the importance of natural gas prices to modeled outcomes for New York, LEI evaluated three separate gas scenarios. Under all gas scenarios, congestion across the C/E and UPNY/SENY interfaces is forecast to decline as a result of a lower difference in locational gas prices between eastern and western NY. The declining trend is stronger in those scenarios where the natural gas price difference between eastern and western NY is smallest. Other drivers for the decline in congestion include the entry of new generating resources in eastern NY, especially the LHV and NYC. Retirements of western NY generation also contribute to the lower congestion level when compared to recent years

This Report does not assess or otherwise evaluate the potential impacts of any of the proposed AC transmission projects under review by the NY PSC in Case 13-E-048. LEI's outlook for the NYISO wholesale electricity markets employs the current transmission topology (albeit integrating transmission solutions previously accepted by the NY PSC such as the Transmission Owners Transmission Solution ("TOTS")). Therefore, LEI cannot calculate any benefit to consumers or production cost savings value that could result from the proposed transmission projects.

7 Appendix A: LEI’s Qualifications

London Economics International LLC (“LEI”) is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation, transmission and distribution, with a suite of proprietary quantitative models to produce reliable and comprehensible results. The firm has its roots in advising on the initial round of privatization of electricity, gas, and water companies in the UK. Since then, LEI has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy in virtually all deregulating markets worldwide.

LEI’s areas of expertise straddle both the deregulated/market environments (including for example, price forecasting and asset valuation; wholesale power market analysis; market design (ISO market rules); and competitive procurement) and application of regulatory economics (such as regulated tariff design; cost of service ratemaking and performance based ratemaking; productivity analysis; policy design for incentivizing renewable energy and new technologies; and transmission and distribution network analysis). Provided below is a sample of previous LEI work showcasing its considerable experience, notably in the analysis of future wholesale power market conditions

LEI’s energy and capacity price forecasting experience in NY:

- ***Prepared outlook on New York power prices.*** LEI was retained by a consortium that included a global investment bank and a US renewable energy generator to prepare a 10-year outlook on wholesale New York electricity prices. The paper presented the energy price outlook for four key sub-regions of the New York power market and annual average Unforced Capacity ("UCAP") market-clearing prices for the Rest-of-State ("ROS"), New York City (NYC) and Long Island (LI) zones. Our analysis suggested that energy prices across the four modeled zones followed similar patterns due to the influence of gas prices and the new entry and retirement schedule. Findings also showed that UCAP prices reflected the internal reserve margins in each zone.

- ***Conducted New York Market Study.*** LEI prepared a market study and a long-term energy and capacity price forecast for the New York power market, in preparation for RG&E's rate case. Our report summarized both the assumptions that underpinned the modeling and the results that stemmed from it, under three alternative scenarios.

- ***North East Capacity Markets Analysis:*** LEI was retained by a major Canadian power producer to project, using LEI's proprietary pool model, energy prices in three distinct regional markets in the US. The project involved a number of “most-likely” scenarios for each of the markets. LEI's deliverables included a detailed report for each of the market, discussing the structure of the markets and the modeling results.

- ***New York Energy Market Imports Revenue Forecast:*** LEI was retained by a major Japanese power utility to prepare an independent analysis of expected revenues over a

30-year period for a proposed acquisition of a 945 MW cogeneration facility in New Jersey with connections to both NYISO and PJM markets. The report included a detailed analysis of improvements in energy sector valuations over the preceding two years and an asset valuation based on the results of LEI's independent pro forma analysis.

- ***New York Energy Market Forecast:*** LEI was retained by a US power utility to prepare a market study and a long-term energy and capacity price forecast for the New York power market in support of the client's rate case. LEI's report summarized both the assumptions that underpinned the modeling and the results that stemmed from it, under three alternative scenarios.

- ***New York, New England and Canadian Capacity Market Analysis:*** LEI was retained by a major Canadian power producer to prepare a study of available capacity resources in four jurisdictions neighboring Quebec—i.e., New Brunswick, New England, New York, and Ontario. The delivered report determined whether there was unforced capacity (UCAP) available for sale to the client by first considering the scope of each market's internal resource adequacy requirements and capacity market institutions, if any. This included a quantitative analysis and forecast of available resources in each market. The report started with an overview of capacity market dynamics and/or resource adequacy obligations in neighboring markets, a description of how each market counts and qualifies capacity resources, and an assessment of market rules for exporting UCAP from neighboring markets into Quebec.

- ***NYSEG Divestiture Support:*** LEI served as lead market advisor for AES in its successful bid for NYSEG's coal-fired assets. LEI developed electricity and capacity forecasts for the New York power market, a long-term outlook on the functionality of market rules, and an evaluation of the NYSEG portfolio. Working alongside the AES team, LEI assisted in the assessment of various fuel management strategies and relative value of joint venture/power purchase agreements. LEI participated throughout the financing process, walking members of the financial community through the detailed analysis during ratings agency presentations and the roadshow to investors and analysts.

LEI's NY markets experience:

LEI has significant NYISO market experience ranging from energy market analysis and price forecasting, capacity market design advisory and market analysis, advisory on Renewable Energy Credits ("REC") , market power analysis, and longer term strategic investment analysis. Below is a sample of some of this experience:

- ***Transmission cost-benefit and macroeconomic impact analyses:*** LEI performed a detailed cost-benefit analysis and macroeconomic impact analysis in support of Transmission Developers, Inc.'s ("TDI") Champlain Hudson Power Express ("CHPE") application for siting approval at the New York Department of Public Service ("DPS"). LEI's analysis on economic effects was the cornerstone of the settlement agreement reached between TDI and a number of New York agencies. LEI Managing Director, Julia Frayer, acted as independent expert on behalf of TDI and prepared updated study results on energy market impacts, capacity market impacts and also macroeconomic benefits stemming from the operation of the CHPE project. LEI's testimony was used in the DPS proceeding in the summer of 2012.

- ***Impact of new transmission line from Northern Maine to NYC:*** LEI advised a major transmission company on the financial implications of a proposed new 400kV transmission line linking northern Maine to New York City and Connecticut. Under this engagement, LEI analyzed the impact of new transmission, assuming it delivered 100% carbon-free energy, on electricity prices and emissions levels in New York and New England.

- ***NY Hydro Valuation***: LEI was engaged by a large Canadian hydro generator to evaluate the potential renewable premium associated with its hydro assets in North America. LEI developed an economic model to project legacy Renewable Energy Certificate ("REC") prices in New York and New England. LEI also provided alternative methodologies such as projecting the premium based on forecasted carbon allowance prices and analyzing potential sales to large corporations on a voluntary basis.

- ***Acquisition Market Power Analysis***: LEI performed a competitive analysis screens for a client's potential acquisition of several generation assets in New England, New York, and PJM. LEI used the Herfindahl-Hirschman Index ("HHI") analysis to determine if there will be competitive concerns on the acquisition of these plants. The work product was eventually submitted as evidence to the NY PSC.

- ***NYISO, NE-ISO REC Market Analysis:*** LEI was engaged by a large Canadian hydro generator to evaluate the potential renewable premium associated with its hydro assets in North America. LEI developed an economic model to project legacy Renewable Energy Certificate ("REC") prices in New York and New England. LEI also provided alternative methodologies such as projecting the premium based on forecasted carbon allowance prices and analyzing potential sales to large corporations on a voluntary basis.

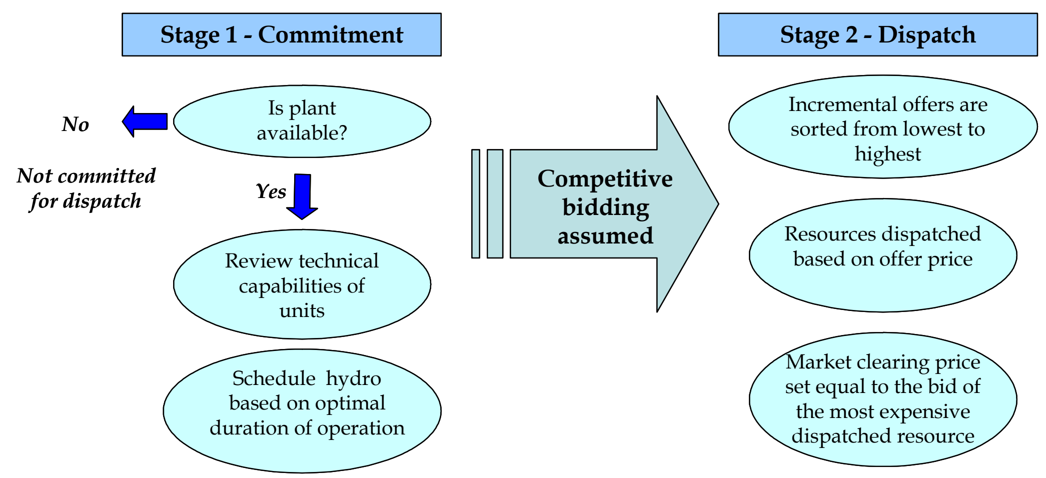
- *New York Market White Paper:* LEI was retained by a Canadian nuclear power generator to conduct a comprehensive review and analysis of the New York market, which culminated in a white paper. The scope of the project involved: analysis/ review of state regulatory environment, NYISO market design, wholesale generation market, supply-demand balance, demand projections, transmission/ congestion issues, new plant additions, environmental compliance requirements, fuel price forecasts, restructuring status, key independent power producers, as well as distribution and retail supply.

8 Appendix B: Introduction to POOLMod

To forecast wholesale energy market prices, LEI employs a proprietary simulation model, POOLMod, as the foundation for the annual energy prices over the forecast horizon. POOLMod simulates the dispatch of generating resources in the market subject to least cost dispatch principles to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch. The initial stage of analysis requires the development of an availability schedule for system resources. First, POOLMod determines a 'near optimal' maintenance schedule on an annual basis, accounting for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. Then, POOLMod allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 39. POOLMod's two-stage process



POOLMod next commits and dispatches plants on a daily basis. Commitment is based on the schedule of available plants net of maintenance, and takes into consideration the technical requirements of the units (such as start/stop capabilities, start costs (if any), and minimum on and off times). During the commitment procedure, hydro resources are scheduled according to the optimal duration of operation in the scheduled day. They are then given a shadow price just below the commitment price of the resource that would otherwise operate at that same schedule (i.e., the resource they are displacing). Shadow-pricing allows the resulting modeled clearing prices (LMPs) to reflect the opportunity costs of hydroelectric resources that have the capacity to store water or shift their water release profile within the day and between days and seasons.

In addition, POOLMod is a transportation-based model, giving it the ability to take into account thermal limits on the transmission network. POOLMod also uses a heuristic, serial-limited transportation algorithm to determine LMPs subject to identified transmission limits. It is very similar to other production-cost based transportation models available commercially.[26] The other commercially available models typically approach the dispatch decisions through linear programming-based optimization. In LEI's experience, the heuristic approach and optimization approaches produce very similar results, assuming similar sets of input data. However, POOLMod has quicker run times given its heuristic algorithms, especially as modeled markets increase in terms of complexity.

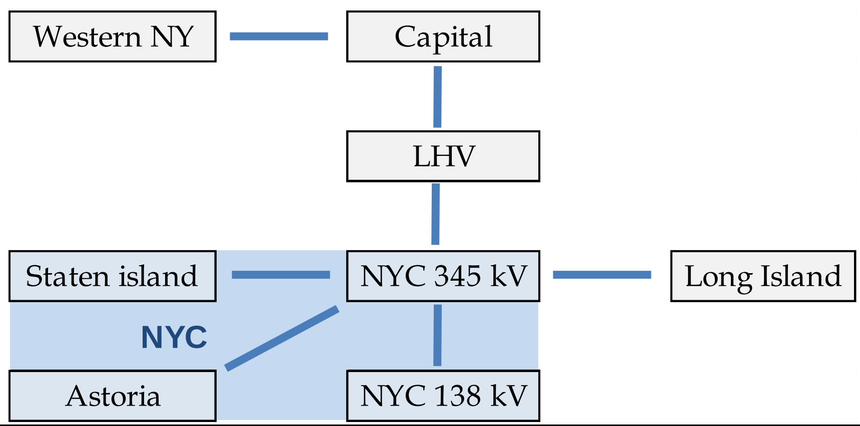
[26] In addition to transportation algorithm models, there is another class of system models, referred to as AC-based or DC-based or load flow models (for example, GE Energy's Multi-Area Production Simulation Software, or GE MAPS). Such models stem from engineering tools used to model detailed transmission elements of the system. It takes substantial time to run these models given that most power systems are composed of thousands of transmission elements; thus, these models are typically less suited for long term economic analysis and extensive sensitivity testing. Load flow models are typically run for a sample set of intervals (i.e., typical day or peak hour of the year) rather than chronologically for every hour of each day in a multi-year timeframe.

9 Appendix C: Detailed assumptions for wholesale power market simulations

9.1 System Topology and transmission limits

For modeling the energy market, LEI groups the eleven NYCA load zones into five distinct sub-regions based on the major transmission interface constraints in the state. Therefore, LEI models a Western NY ("WNY") zone comprised of zones A, B, C, D, and E; Capital ("CAP") is zone F; LHV represents zones G, H, and I; New York City is Zone J; and Long Island is Zone K. Figure 40 illustrates the NYCA system representation in POOLMod.

Figure 40. POOLMod NYCA system representation



LEI's model reflects local load pockets or local constraints within the sub-market regions. The NYC zone is modeled as four separate load pockets: 345 kV, 138 kV, Staten Island, and Astoria. For the purposes of presenting results, however, load pocket results have been aggregated into five sub-market regions.

LEI relies on thermal or stability interface transmission limits published in documents such as Operating Studies or elsewhere on the NYISO OASIS website, as well as values obtained from power flow studies.

Given the NY PSC's approval of new transmission to increase access to existing generation resources on Staten Island,[27] LEI has relaxed the constraint on the Staten Island to 345 kV load pocket in 2017 by 480 MW.[28]

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[27] New York Public Service Commission. *Indian Point Contingency Plans Move Forward*. October 17, 2013. <http://www3.dps.ny.gov/pscweb/WebFileRoom.nsf/Web/A0167A43AAA2952585257C07005A9F37/$File/pr13076.pdf?OpenElement>

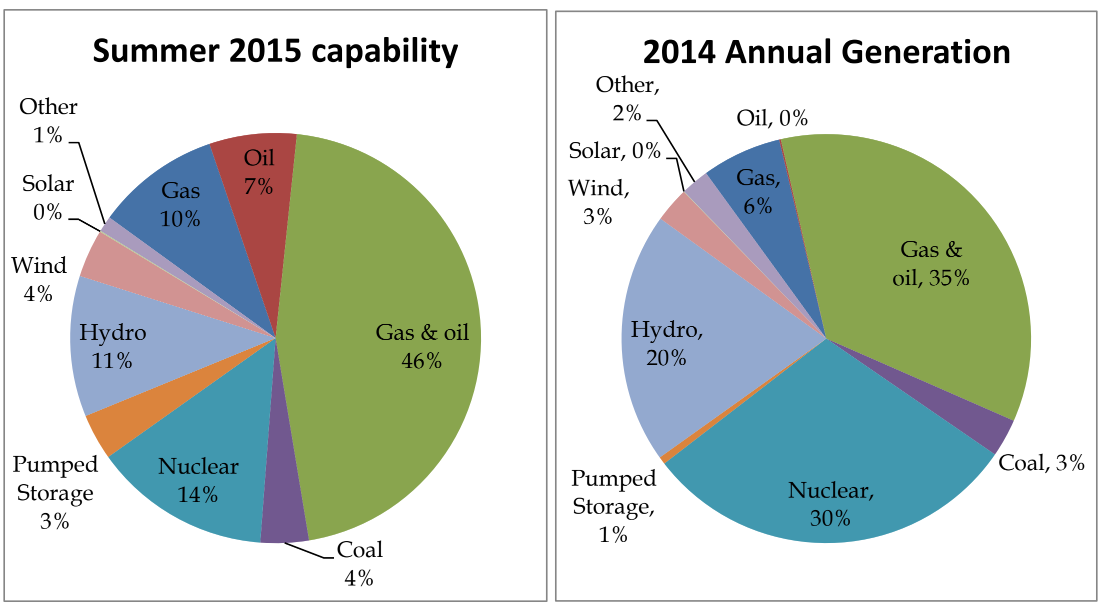
[28] New York Transco Participants. *The Response to the New York State Energy Highway Request for Information*. May 30, 2012. P 37. <http://www.nyenergyhighway.com/Content/documents/70.pdf>

9.2 Electricity Supply Resources

LEI models existing generators within the NYCA from data based on the 2015 Load and Capacity Data report ("Gold Book") published by the NYISO,[29] which provides each generator's most recent seasonal (summer and winter) capacity as of April 2015. The Gold Book data is supplemented with plant operating parameters (heat rates, variable O&M, forced outage rate, etc.) from a commercial database which relies on NERC GADS data. NERC GADS data provides annual operational statistics by unit type and size from NERC's annual survey of plant operators. GADs identifies 63 classes of units based upon their prime mover type, fuel and capacity, to identify units in similar peer groups.

As can be seen from Figure 41, NYCA's summer 2015 installed capacity of 38,666 MW comprises around 56% of the generation capacity using natural gas as a fuel. Baseload generation is made up of nuclear and hydro facilities which represent respectively 14% and 11% of system capacity. Wind capacity, currently totalling 1,461 MW, represents 4% of the total capacity in the state. In terms of annual generation, nuclear and natural gas are the major sources of electricity.

Figure 41. NYCA summer capability and annual generation by fuel type



Source: NYISO. *2015 Load & Capacity Data*. April 2015

9.2.1.1 Retirements

LEI consults various sources to establish its outlook on generator retirements and also perform its own economic analysis to retire plants from the market if their revenues cannot cover the

[29] NYISO. *2015 Load & Capacity Data*. April 2015.

minimum going forward fixed costs three years in a row, consistent with economically rational business behavior. Figure 42 illustrates the generators retiring over the forecasted modeling horizon (2016-2034).

Figure 42. LEI modeled generator retirements

Retirements					
Plant Name	Fuel	Capacity	Zone	Capacity Zone	Year
Astoria GT 10,11,12,13	Natural Gas	120	J	NYC	2018
Port Jefferson	Natural Gas	360	K	LI	2021
Cayuga	Coal	320	C	ROS	2017
Dunkirk	Coal	100	A	ROS	2016
Ginna	Nuclear	614	B	ROS	2019
Nine Mile Point 1	Nuclear	640	C	ROS	2030
Indian Point 2	Nuclear	1300	H	NCZ	2034

In the case of the Astoria Gas Turbines, their owner (NRG) has already announced their retirement. The coal-fired Cayuga in Western NY is currently operating under a reliability agreement and is assumed to retire at the end of 2017 when the agreement expires. The last coal-fired unit at Dunkirk is also presumed to retire when the repowered, gas-fired units come online in 2016. All of these retirements are detailed in NYISO's 2015 Gold Book. Port Jefferson, an older steam turbine generator located on LI, is assumed to retire when new, contracted generation comes online (Caithness II) in 2021.

The Ginna nuclear plant has recently filed with FERC a Reliability Support Services Agreement under, which it seeks to recover its going-forward costs[30]. According to the FERC filing, Ginna cannot recover its costs under the current energy and capacity market conditions. The proposed reliability agreement expires in 2018, after which LEI assumes that the nuclear plant will retire. This view is consistent with the expectation that the NYSIO and local utility would be looking for transmission or other alternatives to solve the reliability issues brought by Ginna's retirement.

Finally, LEI assumes that the Nine Mile Point 1 and Indian Point 2 nuclear power plants will retire at the end of their nominal 60-year service life. This scenario has Nine Mile Point 1 retiring at the end of 2029 while Indian Point 2 would retire at the end of 2033[31].

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[30]http://www.mondaq.com/unitedstates/x/389842/Utilities/FERC+Sets+Ginna+Nuclear+Facility+Agreement+For+Hearing

[31] US Nuclear Regulatory Commission. http://www.nrc.gov/info-finder/region-state/newyork.html

9.3 New Entry

In order to take into account new generation projects, LEI reviews the NYISO interconnection queue to incorporate known projects that are relatively certain to reach completion and commercial operation. In general, LEI includes projects that are under construction, have secured financing or have accepted their System Deliverability Upgrade ("SDU") and System Upgrade Facilities ("SUF") costs following a Class Year process.

New entry decisions are also conditioned on modeled outcomes such that additional new entry is introduced if and when it is economically feasible given the simulated market dynamics. Figure 43 shows the assumptions and calculation of the New Entry Trigger Price ("NETP") of NYISO for generic combined cycle plants, which are considered the most economic new entry in New York. While some NETP parameters are the same across New York State, some parameters vary by region. For example, LEI applies different capital costs as the land acquisition cost, labor cost, and construction costs are, to some degree, region-specific inputs (e.g. the capital costs in NYC and LI are significantly higher than eastern NY and western NY).

Figure 43. Cost assumptions of natural gas CCGT generic new entry, 2016

	WNY	ENY	NYC	LI
real capital cost, $/kW	$ 1,303	$ 1,529	$ 1,993	$ 1,777
leverage	60%	60%	60%	60%
debt interest rate	6%	6%	6%	6%
corporate income tax rate	40%	40%	40%	40%
after-tax required equity return	10%	10%	10%	10%
debt financing term	20	20	20	20
equity contribution capital recovery term	20	20	20	20
construction time	36	36	36	36
heat rate, Btu/kWh	6,430	6,430	6,430	6,430
nominal variable O&M, $/MWh	3.9	3.9	3.9	3.9
nominal fixed O&M, $/kW/year	14.3	14.3	14.3	14.3
average annual load factor	60%	80%	80%	80%
fuel prices ($/MMBtu)	$ 4.2	$ 4.2	$ 4.9	$ 4.9
All-in break-even cost at assumed LF, $/MWh	$ 65.0	$ 56.0	$ 67.0	$ 64.0
Levelized all-in fixed cost, $/kW-year	$ 170.0	$ 168.9	$ 215.9	$ 194.0

Note: All-in fixed cost includes interest and principal debt payments and fixed O&M.
Sources: EIA AEO 2015; NYISO. *Proposed NYISO Installed Capacity Demand Curves for Capability Years 2014/2015, 2015/2016 and 2016/2017*; LEI

Figure 44 illustrates the new generators assumed by LEI to come online over the 2016-2034 forecasting horizon.

Figure 44. LEI modeled generator new entry

New Entry					
Plant name	Fuel	Capacity	Zone	Capacity Zone	Year
Bowline 2 Refurbishment	Natural Gas	384	G	NCZ	2015
Dunkirk Repowering	Natural Gas	435	A	ROS	2016
Berrians I/II	Natural Gas	250	J	NYC	2018
CPV Valley	Natural Gas	720	G	NCZ	2018
Berrians III	Natural Gas	250	J	NYC	2019
Caithness II	Natural Gas	750	K	NYC	2021
Generic CCGT J 2025	Natural Gas	400	J	NYC	2025
Generic CCGT J 2029	Natural Gas	400	J	NYC	2029
Generic CCGT F 2031	Natural Gas	600	F	ROS	2031
Generic CCGT G 2034	Natural Gas	800	G	NCZ	2034
Generic CCGT J 2034	Natural Gas	400	J	NYC	2034

The Bowline 2 refurbishment and Dunkirk repowering projects have met the NYISO's inclusion rule for the 2014 Comprehensive Reliability Plan Base Case and are included in the 2015 Load and Capacity Data report. As such, LEI has included these projects in its station database.

The 720MW CPV Valley proposed CCGT in zone G was entered into and has completed the 2011 Class Year process. It accepted its SDU and SUF cost allocation[32]. Furthermore, CPV has been found exempt from the NCZ BSM rules which would allow it to clear its entire capacity in the NYISO auction[33]. Finally, CPV announced in June 2015 that it closed financing for the project[34]. For all these reasons, LEI has included the project in its station database.

The Caithness Long Island II project was selected by the Long Island Power Authority ("LIPA") in July 2013 following an RFP for new on-island generation. The project is a 750MW CCGT in zone K[35].

[32]http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Interconnection_Studies/Notices_to_Market_Participants/Class%202011%20Notice%20of%20Completion%20of%20Decision-Settlement%20Process_10-15-2013.pdf

[33]http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Buyer_Side_Mitigation/Class_Year_2011/MMU%20Report%20re%20MET%20for%20CPV_Final_3-7-14.pdf

[34] http://www.cpv.com/press_releases.html#web

[35] http://www.caithnesslongisland.com/caithness-long-island-ii/

The Berrians I/II/III projects are proposed CCGT generators located in NYC and scheduled to come online in 2018 and 2019[36]. These projects would add 500MW of new capacity. Berrians I/II went through the 2011 Class year process[37], while Berrians II went through the 2012 Class Year process[38]; all have accepted the SDU and SUF cost allocation. The Berrians projects will however be subject to BSM mitigation in the NYC capacity markets[39], although LEI's analysis shows that they will clear their entire capacity within two years.

In order to assess the economic viability of the Berrians projects, LEI compared the forecasted energy and capacity revenues for each generator against its assumptions for cost of new CCGT generation in NYC[40].

Figure 45. LEI forecasted revenues for the Berrians projects

	$/kW-year	2018	2019	2020
Berrians I/II	Energy Revenue	$72.0	$68.7	$73.8
	Capacity Revenue	$144.5	$137.2	$143.9
	Total Revenue	**$216.5**	**$205.9**	**$217.7**
	Revenue Requirement	$224.6	$229.1	$229.3
	$/kW-year	**2019**	**2020**	**2021**
Berrians III	Energy Revenue	$73.3	$78.2	$76.0
	Capacity Revenue	$137.2	$143.9	$152.2
	Total Revenue	**$210.5**	**$222.1**	**$228.2**
	Revenue Requirement	$229.1	$229.3	$233.9

LEI does not have the specific cost structure of the project and it is possible that the developer can get the project online for a cost inferior to LEI's generic estimate. Considering the

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36 See note 12 on page 37

37http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Interconnection_Studies/Notices_to_Market_Participants/Class%202011%20Notice%20of%20Completion%20of%20Decision-Settlement%20Process_10-15-2013.pdf

38http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Interconnection_Studies/Notices_to_Market_Participants/Class%202012%20Notice%20of%20Completion%20of%20Decision-Settlement%20Process.pdf

39http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Buyer_Side_Mitigation/Class%20Year%202012/Notice%20of%20BSM%20Determination%20January%2013,%202015.pdf

40 LEI selected the *Henry Hub gas with pipeline expansion* scenario for this analysis as it results in energy and capacity credits which are midway between results from the other two natural gas pricing scenarios

commitment made by the developer in the class year process, LEI has elected to include the Berrians I/II/III projects in its station database.

Finally, Figure 46 illustrates the forecasted revenues for generic new entrants over the 2016-2034 horizon

Figure 46. LEI forecasted revenues for generic new entrants

$/kW-year		2025	2026	2027
Generic 2025 new entry (zone J)	Energy Revenue	$90.6	$86.9	$91.6
	Capacity Revenue	$163.8	$175.1	$192.4
	Total Revenue	**$254.4**	**$262.0**	**$284.0**
	Revenue Requirement	$248.4	$253.4	$258.5
$/kW-year		**2029**	**2030**	**2031**
Generic 2029 new entry (zone J)	Energy Revenue	$93.5	$103.3	$106.9
	Capacity Revenue	$177.5	$188.5	$205.9
	Total Revenue	**$271.0**	**$291.8**	**$312.8**
	Revenue Requirement	$263.9	$269.2	$274.6
$/kW-year		**2034**		
Generic 2034 new entry (zone J)	Energy Revenue	$121.9		
	Capacity Revenue	$203.3		
	Total Revenue	**$325.2**		
	Revenue Requirement	$286.0		
$/kW-year		**2031**	**2032**	**2033**
Generic 2031 new entry (zone F)	Energy Revenue	$101.2	$96.4	$101.3
	Capacity Revenue	$102.8	$112.1	$121.8
	Total Revenue	**$203.9**	**$208.5**	**$223.1**
	Revenue Requirement	$196.6	$196.9	$200.9
$/kW-year		**2034**		
Generic 2034 new entry (zone G)	Energy Revenue	$108.5		
	Capacity Revenue	$131.9		
	Total Revenue	**$240.4**		
	Revenue Requirement	$224.1		

9.4 Renewables

New York State encourages the development of renewable resources through its Renewable Portfolio Standard ("RPS") program. New York's RPS program was created by order of the

New York Public Service Commission ("NYPSC") on September 24, 2004,[41] with an initial requirement that 25% of consumption be provided by generators from renewable resources by 2013. This has more recently been expanded to 30% by 2015.[42] Unlike other northeast states where Renewable Energy Credits ("RECs") are traded, New York State Energy Research and Development Authority ("NYSERDA") is designated as the central procurement administrator for the RPS program and holds solicitations for incremental renewables needed to meet the RPS target.

New York State's RPS program divides incremental renewable resources into two tiers: (i) the "main tier" comprised primarily of medium to large-scale generators that sell into the NYISO's wholesale market, and (ii) a "customer-sited tier" consisting of smaller resources that only produce electricity for a single site. LEI models the main-tier requirement, which is about 93% of the overall RPS requirement, as the customer-sited generation is taken into account in NYISO's demand forecast. As of December 31st, 2014, NYSERDA has reached 53% of its 2015 RPS procurement and energy targets for the main tier projects[43]

To meet the expanded RPS target, LEI models 1,500 MW of generic new wind resources over the next 10 years at a rate of 150 MW per year. LEI then models 50 MW of new wind generation for each subsequent year over the forecasting horizon

9.5 Fossil fuel price projections (except natural gas)

Figure 47. Fossil fuel price projections (nominal $)

Fuel Price Forecast	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	CAGR
Light Sweet Crude Oil (WTI) ($/bbl)	$63.1	$66.8	$68.3	$70.8	$73.6	$76.8	$80.1	$83.6	$87.0	$90.4	4.10%
No. 2 Heating Oil (NY Harbor) ($/bbl)	$82.7	$86.5	$88.5	$91.7	$95.4	$99.5	$103.7	$108.3	$112.7	$117.2	3.90%
Coal ($/Mmbtu)	$3.6	$3.7	$3.8	$4.0	$4.1	$4.2	$4.4	$4.5	$4.7	$4.8	3.40%

Source: NYMEX, EIA AEO 2015

LEI develops fuel prices based on market trends. Short-term prices are driven by forward market expectations, while longer-term trends are based on more general commodity price paths.

Figure 47 illustrates the first 10 years of prices for oil and coal. The remainder of the forecast follows the same growth rate as the earlier years. Prices for New York Harbor No.2 Heating Oil

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41 Case 03-E-0188, Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard, Order Regarding Retail Renewable Portfolio Standard, September 24, 2004 (2004 RPS Order).

42 Case 03-E-0188, Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard, Order Establishing New RPS Goal and Resolving Main Tier Issues, January 8, 2010 (2010 RPS Order).

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are projected to grow at 3.9% per annum, while coal prices are projected to grow at an annual average rate of 3.4%.

The distillate oil price is based on the heating oil forwards for the first two years, and escalated at the same rate as the EIA 2015 Annual Energy Outlook ("AEO") crude oil forecast in the long term. The residual oil price forecast is based on a multi-year average of the ratio of residual and distillate oil prices.

Given the diversity in coal sourcing, quality, and price, LEI uses plant specific coal price outlooks. LEI begins with an estimate of actual delivered costs, taking into account the type of coal used at each plant (since each coal plant has different sulfur content levels and different contracts for price and transportation), and escalates it with the longer term trends for the commodity (the coal price forecast) and inflation rate from the 2015 EIA AEO.

9.6 Demand

On a yearly basis, the NYISO publishes a 10 year forecast of the expected net energy usage and peak demand within New York State over that period. The forecast integrates a baseline load forecast based on econometrics projections as well as the expected impacts from Energy Efficiency ("EE") programs and the reduction in net load caused by Distributed Generation ("DG") resources. For modeling the energy and capacity wholesale markets, LEI relies on the NYISO load forecast as published in the Gold Book.

9.6.1 NYISO historical demand forecast

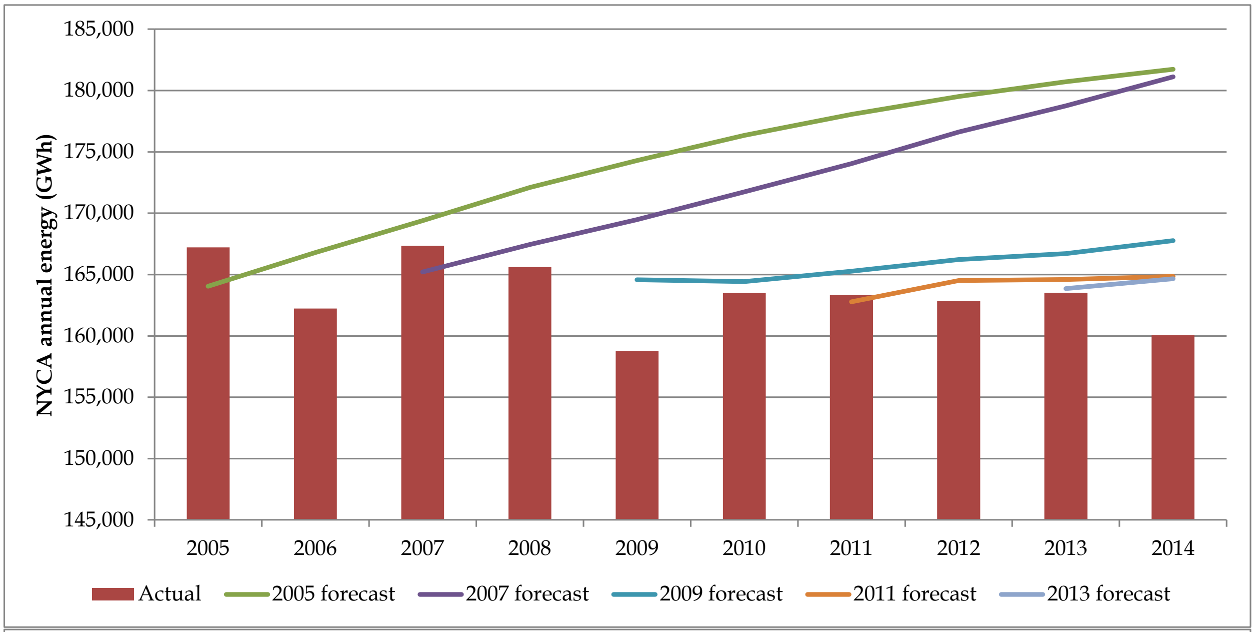
Forecasting electricity demand is a perilous exercise as actual demand is dependent on a variety of factors. The most important drivers of electrical demand are:

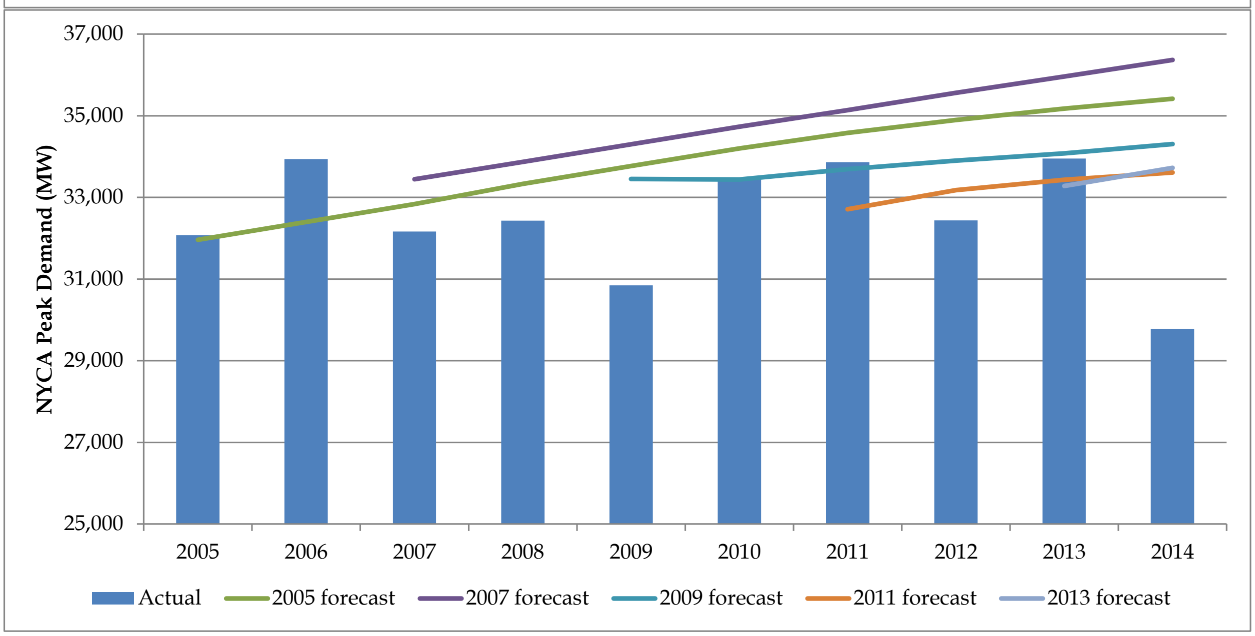
- economic activity;
- weather; and
- in recent years, Energy Efficiency ("EE") and Distributed generation ("DG").

Some drivers of demand, such as weather, are impossible to predict, which is why NYISO produces a weather-normalized electricity forecast. The forecast represents a 50/50 scenario, meaning that there is a 50% probability that the electricity forecast will be above or below the reference value.

Figure 48 illustrates energy and peak demand of the last 10 years within NYCA with an overlay of past NYISO demand forecasts.

Figure 48. Past NYISO energy and peak demand forecasts compared to actual NYCA energy demand





Source: NYISO Gold Book, 2005-2015

Prior to 2008, all indicators pointed towards a robust growth in electricity demand driven by an equally strong growth in economic activity within the state. NYISO was then forecasting a growth in energy usage of between 1.1% and 1.3% per annum.

However, following the 2008-2009 recession, NYISO significantly reduced its outlook on energy consumption to account for the lower growth in economic activity. The 2009, 2011 and 2013 forecasts show energy usage growth of between 0.4% and 0.6% per annum.

As for the peak demand outlook, NYISO forecasted in 2008 and 2009 an annual growth of around 1.2%. While NYISO revised the growth rate in later forecasts, as of 2013 the peak demand outlook still showed an annual growth rate of 1.0% per annum for the next 10 years.

9.6.2 NYSIO 2015 Gold book forecast

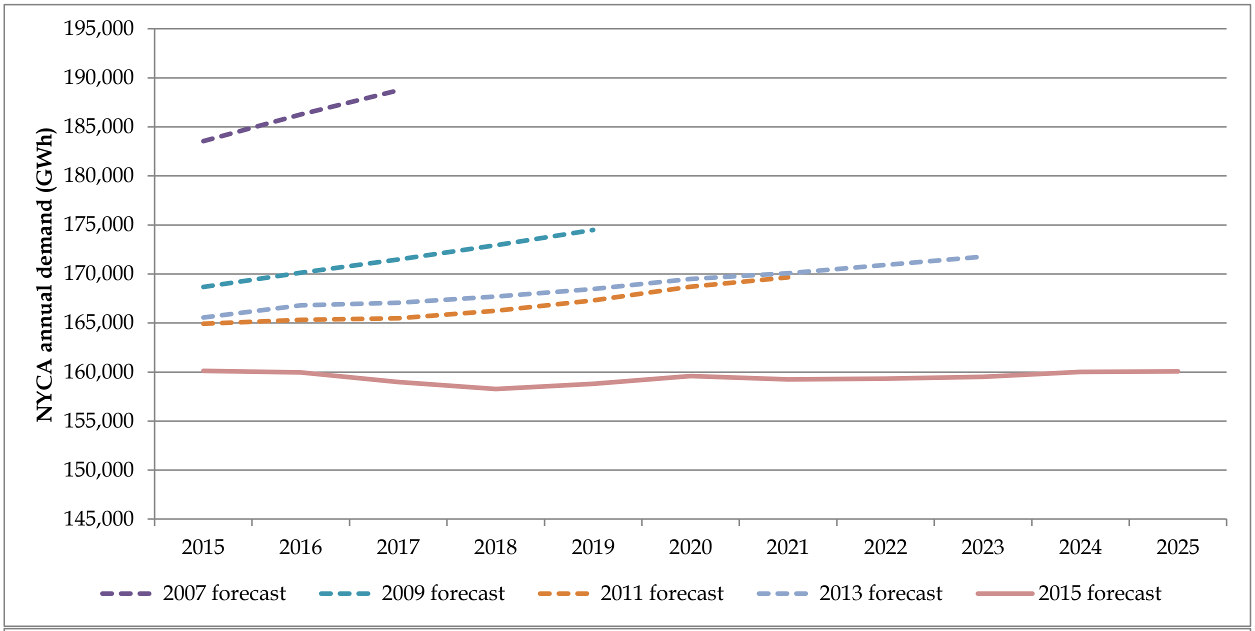
Figure 49 illustrates NYISO's latest 10 year forecast for energy and peak demand within NYCA from the 2015 Gold Book as compared to forecasts from previous years.

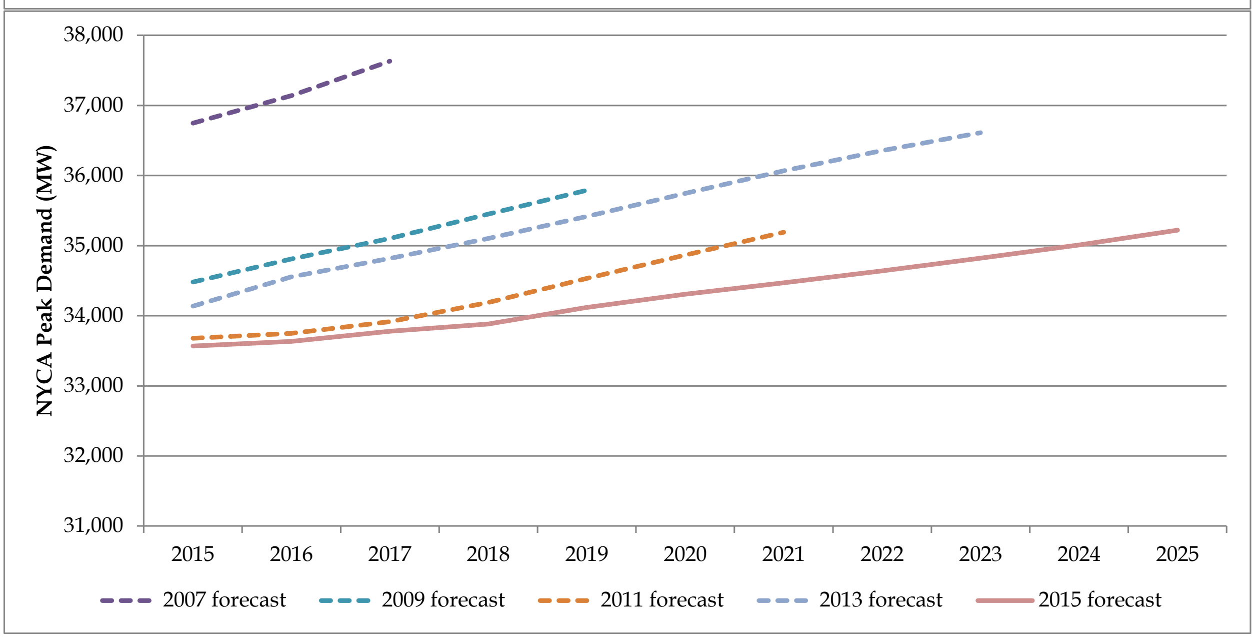
While NYISO has been reducing its energy usage growth forecast over the last 10 years, the 2013 10-year outlook still showed an annual energy usage growth of 0.5%. The 2015 forecast, however, shows no energy growth on average over the next 10 years within NYCA and even a small decline between 2015 – 2018. However, there are some disparities across various zones within the state. While energy usage in the Western regions has been relatively flat, mid-state regions (zones E and F) have exhibited strong growth but zones G through K show a persistent decline.

The peak demand forecast, on the other hand, is expected to grow about 0.5% per annum over the 10-year forecast horizon. Therefore, while there is no growth in energy usage, the growing peak demand forecast forces the NYISO to procure supplemental resources through the capacity market in order to meet this growing demand. The peak demand growth however is still forecasted to be smaller than in previous years.

The lower forecasted growth in energy usage and peak demand is a consequence of the projected impact of statewide energy efficiency programs and the growing impact of distributed behind-the-meter energy resources such as retail solar photovoltaic or combined heat and power. These resources are helped through programs such as New York State's NY-SUN Initiative, Clean Energy Fund and Green Bank. Moreover, the growth of DG is expected to be facilitated by New York State's Reforming Energy Vision (REV) initiative.

Figure 49. NYISO 2015 energy and peak demand forecast compared to previous forecasts



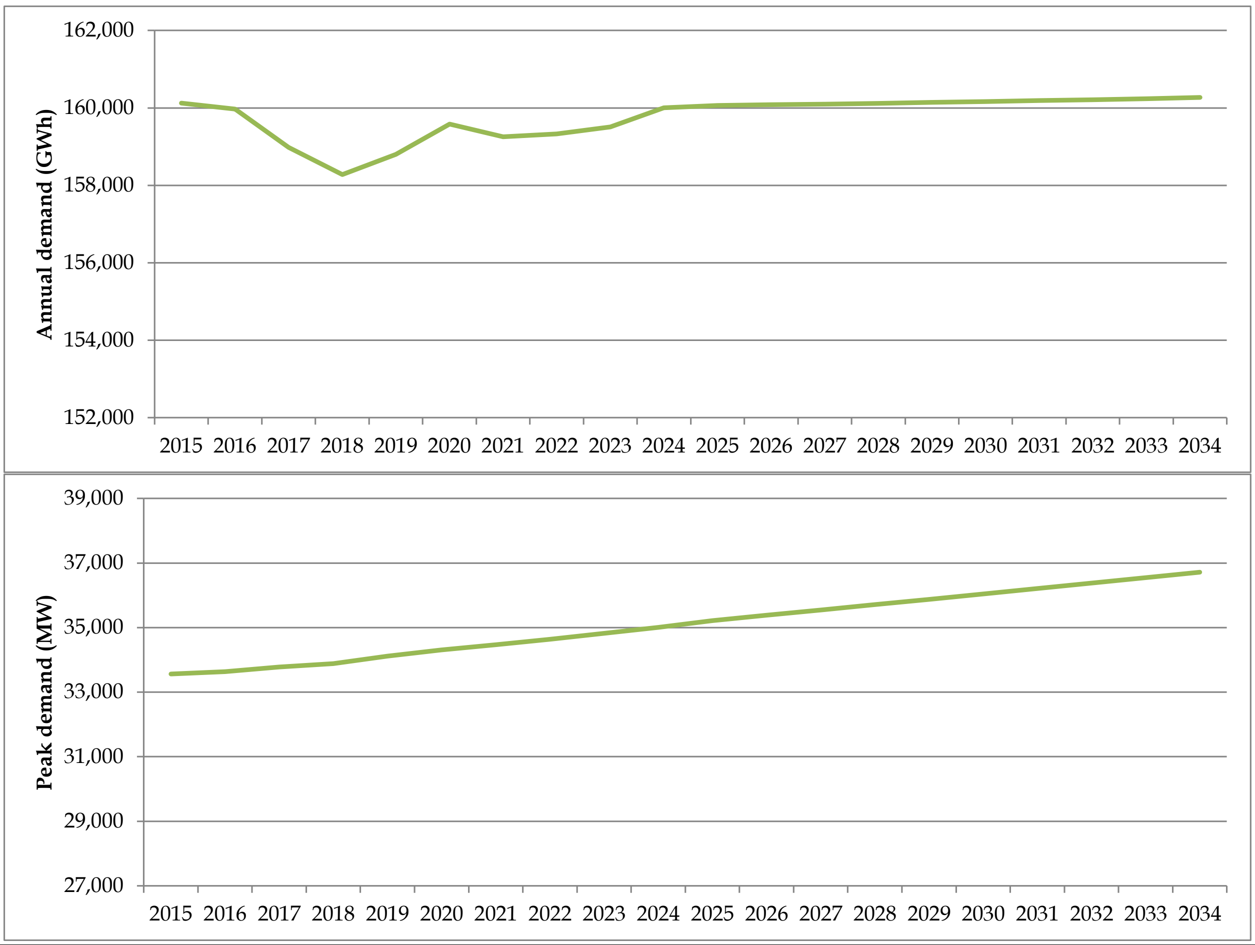


Source: NYISO Gold Book, 2005-2015

9.6.3 LEI 20-year demand forecast

To obtain a 20-year load forecast (consistent with LEI's forecasting horizon), LEI extrapolates the load growth from the later years of the NYISO 2015 Gold Book forecast as shown in Figure 50.

Figure 50. LEI 20-year energy and peak demand forecast



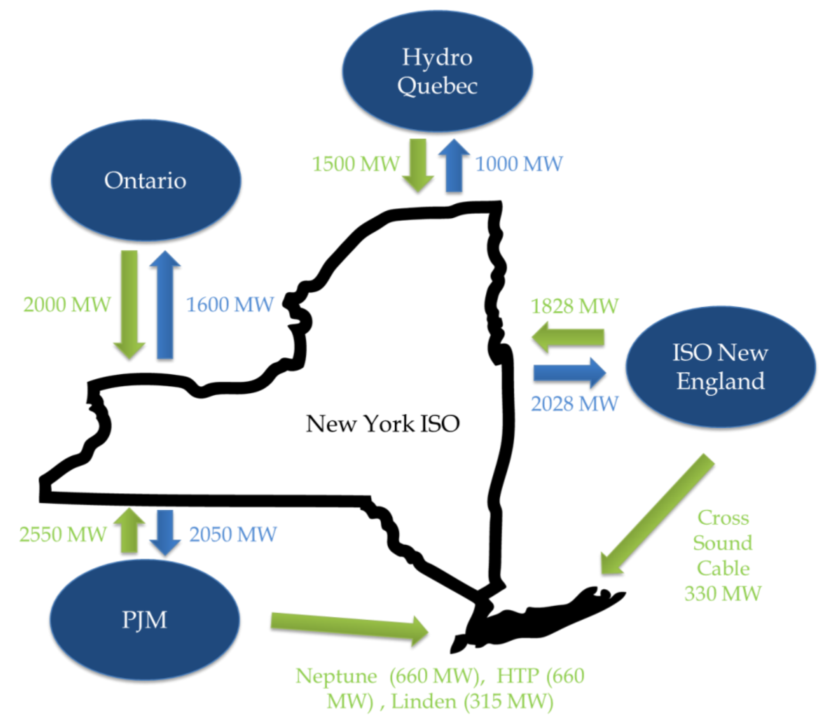
Using Heating Degree Day ("HDD")/Cooling Degree Day ("CDD") data from National Climatic Data Center ("NCDC"), a division under National Oceanic and Atmospheric Administration ("NOAA"), LEI selected 2011 as an appropriate weather-normalized base year to forecast demand following a review of average heating and cooling degree days in each year against the ten year average.

LEI applies 2011 hourly load profile to the 20 year demand forecasts of total energy usage and summer peak demand to obtain a load distribution over its forecasting horizon. This load distribution is then used as an input to the POOLMod simulation.

9.7 Import and export flows

Historically, New York, on a state-wide basis, has been a net importer from New England ("ISO-NE"), PJM, Ontario, and Québec; recent trends however show net exports to ISO-NE because of high natural gas prices in that region driving up the electricity prices. To model the interchange between New York and external regions, LEI reviewed historical hourly interchange data.

Figure 51. External transfer limits



Note: Linden VFT and HTP interconnect to NYC, while Neptune interconnects to LI
Source: NYISO. *2014 Reliability Needs Assessment*. June 20, 2014.

For Ontario, the annual target is based on the 2013-2014 average annual total interchange, to take into account the most recent trade behaviour. For ISO-NE, target is based on 2013-2014; NYISO is now a net exporter to ISO-NE, which is driven by the reversal of Roseton in 2012 from an intertie which imports to one which exports. Ontario imports are expected to diminish over time as significant amounts of nuclear generation are taken offline for refurbishment. By 2024, it expected certain nuclear units will return to service, increasing exports again into NYISO.

For Québec, the longer term 2012-2014 average was used to account for variations in hydrology in the hydro-rich province. Imports from Québec are also expected to evolve, with the La Romaine complex coming into service from 2014 to 2020. 2013-2014 PJM interchange data is used for transactions with that control area.

LEI has also included the 660 MW Hudson Transmission Partners transmission line from PJM to NYC, which was energized in summer 2013.

9.8 Emissions allowance costs

The Acid Rain and the Clean Air Interstate Rule ("CAIR") are the two major US Federal level regulations that cap SO_2 and NO_x emissions in New York. Given the US Court of Appeals for the DC Circuit ruling that vacated CSAPR, for the purpose of the current release, LEI assumes CSAPR will start by 2016. The SO_2 and NO_x allowance price is based on forwards published by Bloomberg in the short term, and escalated at inflation over the long term.

The Regional Greenhouse Gas Initiative ("RGGI") is a regional cap-and-trade program that aims to reduce CO_2 emissions from power plants (25 MW or larger) in the northeastern states of the US. RGGI was implemented January 1, 2009. With nine states currently participating, including New York,[44] it is one of the largest carbon programs in the US. Effective January 1, 2014, all participants in the RGGI will be subject to a CO_2 cap of 91 million short tons (down 45% from the previous cap of 165 million tons); of this cap, New York State's base budget in 2014 is 35 million tons.[45] The RGGI cap will decline 2.5% each year from 2015 to 2020. In the modeling, LEI has assumed that states will auction 100% of allowances and all plants will be required to be 100% carbon neutral. In other words, each plant will be required to purchase an allowance to offset every ton of CO_2 it emits.

Figure 52. Emissions allowance cost projections (nominal $/ton)

[$/ton]	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CO_2	5.6	5.8	6.0	6.2	6.4	6.5	6.6	6.8	6.9	7.0
SO_2	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0
NOx	53.1	54.1	55.2	56.3	57.4	58.6	59.8	60.9	62.2	63.4

Source: Bloomberg, ICE, LEI. 2015 prices are used for SO_2 and NOx emissions costs, which are inflated by 2% per annum thereafter. For CO_2, ICE futures are used until 2018, and the average growth rate from 2016 to 2018 is used for 2019 and 2020 (the remaining years where the RGGI cap is declining); CO_2 costs are inflated by 2% per annum thereafter.

On June 2, 2014, the EPA issued the Clean Power Plan ("CPP"), a proposal on carbon pollution guidelines for existing power plants. The CPP proposes to reduce CO_2 emissions from existing fossil fuel-fired power plants in the US by 30% below 2005 levels by 2030. The CPP calls for states to implement their own rules and procedures to achieve their state-specific carbon emissions reduction goals. Specifically, the CPP suggests that states can achieve this goal in one of two ways:

- **Option 1** has a compliance timeframe of 2030 to achieve a 30% reduction below 2005 levels, with an interim target of 26-27% by 2020;

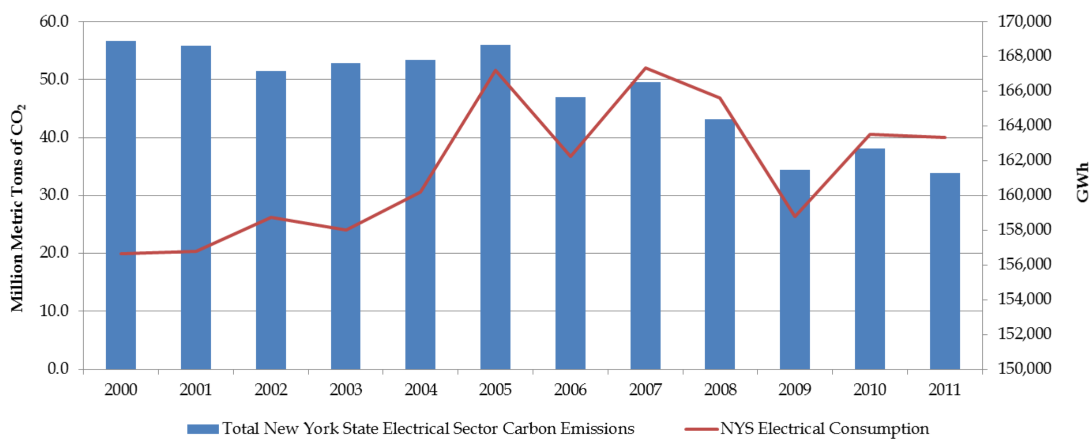
[44] States in RGGI are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. New Jersey withdrew from RGGI in May 2011.

[45] RGGI. *Program Overview*. <http://rggi.org/news/44-program-design/rggi_benefits>

- **Option 2** has a compliance timeframe of 2025 to achieve a 30% reduction below 2005 level, with an interim target of 23% by 2020. Thus, it has a more gradual requirement in the near-term (through 2020), in exchange for faster compliance overall.

New York State has already made significant efforts to reduce carbon emissions. The New York power market has also experienced changes in supply mix since 2005 that has helped curb carbon emissions from in-state power plants: there have been retirements of older coal-fired generation and additions of new, more efficient gas-fired generation. In addition, installation of new wind generation has accelerated over the last decade. Furthermore, the ongoing impact of energy efficiency programs, retail solar PV installations, and reduced overall demand as a result of the 2008 recession has contributed to the considerable reductions in New York State's CO_2 emissions from the power generation sector. Since 2005, the New York power generation sector has already reduced its carbon emissions by almost 40% from 56 million metric tons in 2005 to 33.8 million metric tons in 2011. As New York State has essentially already achieved the EPA CPP, LEI believes there will not be significant additional pressure on RGGI carbon allowance prices.

Figure 53. Total New York State Electrical Sector Carbon Emissions



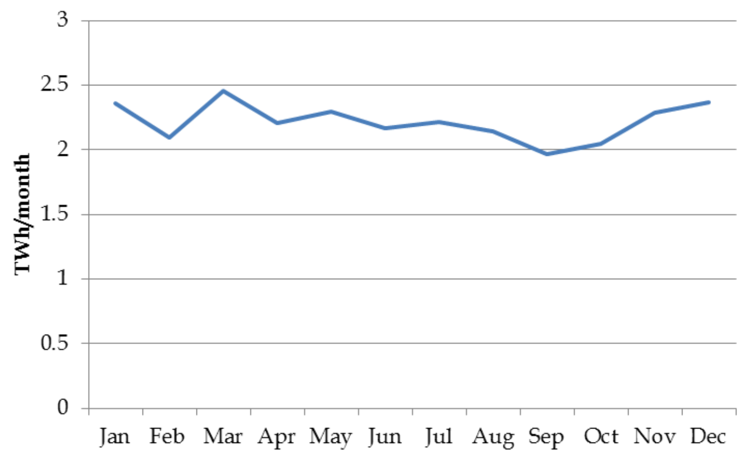
Sources: US EIA. *State CO_2 Emissions*. <http://www.eia.gov/environment/emissions/state/state_emissions.cfm>, third party financial database

Assumptions on carbon emissions price forecasts and the timing of the implementation of a carbon regulation, as well as the compliance mechanism of such program discussed in this report, should be considered illustrative. No assumption provided by LEI on a potential carbon regulatory framework (regional) should be taken as a promise or guarantee of any such occurrence in the future. Moreover, in this report LEI does not make any recommendations as to the timing and/or mechanism of the program or the expected carbon emissions prices.

9.9 Hydrology

To determine the target amount of energy production of the hydroelectric plants, LEI relies on historical monthly production data for individual plants to create typical monthly energy budgets for each plant in our database. Figure 54 presents the energy budget developed for all existing hydro units based on a five year average of historical operations (2010-2014).

Figure 54. Average monthly hydroelectric energy budget for all existing conventional New York hydroelectric plants (TWh/month)



9.10 Capacity Market

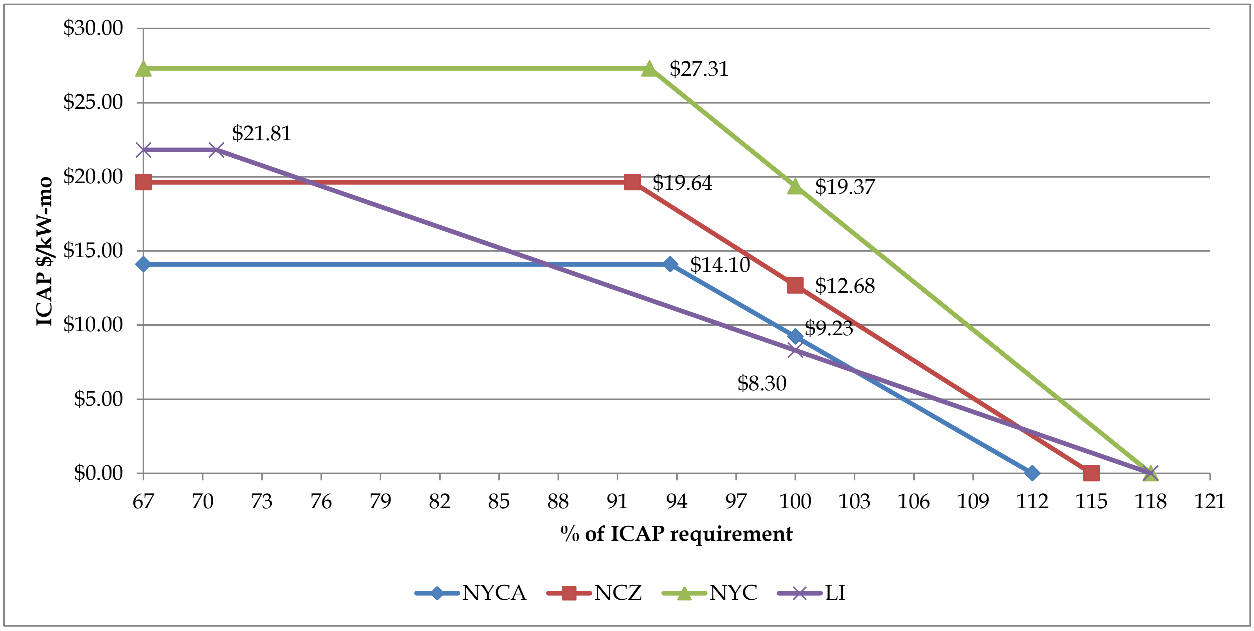
LEI replicates the processes embedded in the NYISO market for determining the equilibrium capacity price, given the supply of capacity in New York State and a downward sloping demand curve.

Overall capacity supply offers are matched with an administratively determined downward sloping demand curve. Capacity prices are determined by the intersection of the offer and demand curves.

LEI relies on the zonal peak load forecasted by the NYISO and its own outlook on other parameters such as the Installed Reserve Margin ("IRM") and Locational Capacity Requirements ("LCR") to determine the annual Installed Capacity ("ICAP") requirement. LEI further uses the annual forced outage rates from its generator database to forecast an Estimated Forced Outage Rate on demand ("EFORd") which is used to determine the Unforced Capacity ("UCAP") requirement.

Figure 55 illustrates the demand curve in place for the 2016-2017 capacity spot auctions held on a monthly basis.

Figure 55. 2016-2017 capacity spot auctions Demand Curve



In the New York Control Area, the system targets a certain reserve requirement above estimated peak demand. The downward sloping portion of the ICAP demand curve must pass through three points. The height of the first point is the maximum possible clearing price for the capacity market (for instance, $14.10/kW-mo for the NYCA demand curve). The second point is defined to be the point where the amount of ICAP supplied is the same as the Minimum Installed Capacity Requirement, or reserve capacity, as defined by the NYCA (for NYCA, this is currently 117% of forecasted peak demand), and where the price of ICAP is equal to the monthly ICAP Reference Price (that number is $9.23/kW-mo for the NYCA). The third point is the Zero Crossing Point, which for NYCA is defined as 112% of reserve capacity.

The IRM is assumed constant over the forecast horizon at 17%, which corresponds to its 2014 and 2015 level. The LCR are also assumed constants over the forecast horizon. Figure 56 illustrates the parameters assumed by LEI over the forecast horizon.

Figure 56. Demand Curve Parameters

Capacity Zone	Reserve Requirement	Demand Curve Length
NYCA	117.0%	112.00%
NCZ	90.50%	115.00%
NYC	93.50%	118.00%
LI	103.50%	118.00%

To determine the future ICAP summer reference points, LEI calculates a growth rate which is then applied to the value from the currently valid demand curves. LEI calculates the growth rate from the estimated increase in the Net Cost of New Entry ("Net CONE") for a peaking unit in all capacity zones. The Net CONE is the levelized, all-in fixed cost for the new peaking unit ("Gross CONE") minus its anticipated revenues from the ancillary services and energy markets.

LEI uses the Gross CONE for the current year from the last DCR as a starting point. This value is assumed to increase with inflation at a rate of 2.2% per year. LEI further calculates the growth rate in energy revenues for proxy peaking units in each of the NYCA, NCZ, NYC and LI capacity zones from its own outlook on energy prices. LEI then applies the weighted average of the Gross CONE and energy revenues growth rates to the current ICAP reference point.

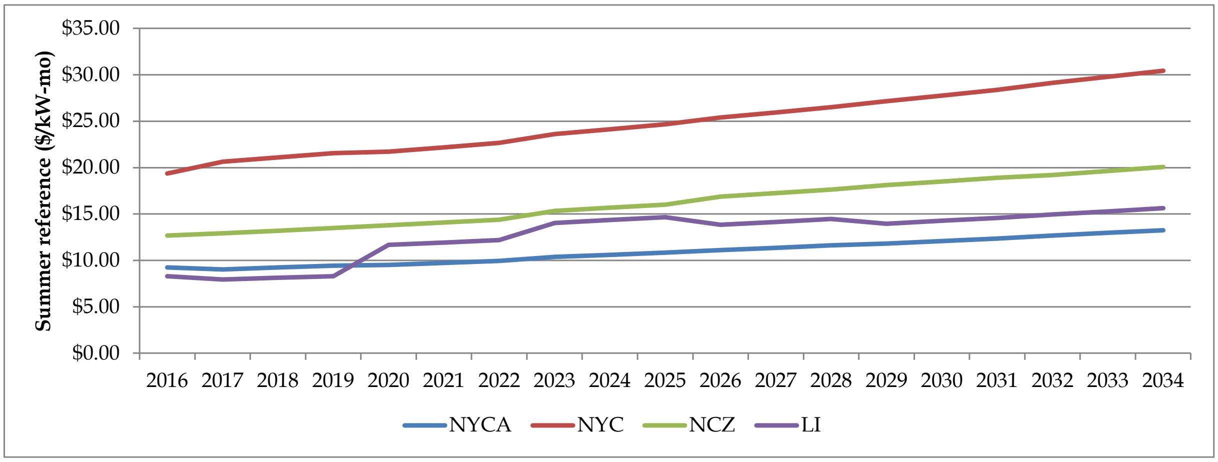
Figure 57 illustrates LEI's calculated ICAP summer reference point under all three natural gas pricing scenarios.

The LI summer reference point is the most volatile as peaking units in LI receive a lot of credits from the energy markets, thus lowering their ICAP revenue requirement. This is the reason why LI Net CONE jumps in 2020, when anticipated revenues from the entry of the Caithness II plant in 2021 reduces their revenues from the energy markets.

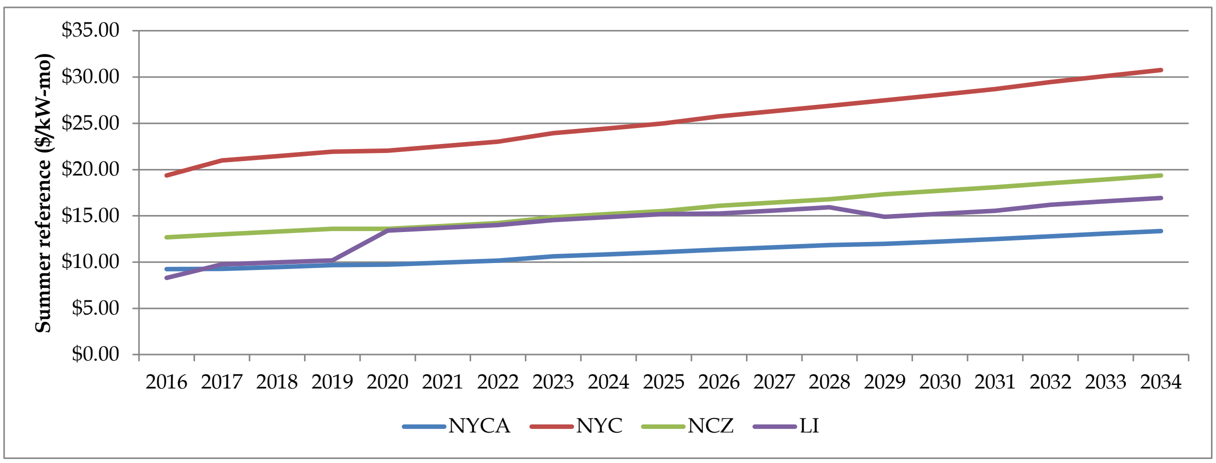
Otherwise the impact of the different natural gas pricing scenarios on the ICAP reference points is pretty modest. Peaking plants in NYCA, NYC and NCZ retrieve a relatively modest percentage of their earnings from the energy markets, therefore a variation of a few percent in their anticipated earnings has an even more modest effect on the reference point.

Figure 57. ICAP summer reference price

Marcellus Shale gas with pipeline expansion scenario



Henry Hub gas with pipeline expansion scenario



Marcellus Shale gas with persistent basis differential scenario