2011 Congestion Assessment and Resource Integration Study

Comprehensive System Planning Process

CARIS – Phase 1

December 20, 2011

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(To be added),

1. Introduction

Pursuant to Attachment Y of its Open Access Transmission Tariff (OATT, or the Tariff), the NYISO performed the first phase of the 2011 Congestion Assessment and Resource Integration Study (CARIS). The study assesses both historic[1] and projected congestion on the New York bulk power system and estimates the economic benefits of relieving congestion. Together with the Local Transmission Planning Process (LTPP) and the Comprehensive Reliability Planning Process (CRPP), the CARIS is the final process in the NYISO's biennial Comprehensive System Planning Process (CSPP) (see Figure 1-1). The 2011 CARIS completes the CSPP process that began with LTPP inputs for the 2010 Reliability Needs Assessment.

CARIS consists of two phases: Phase 1, the Study Phase, and Phase 2, the Project Phase. Phase 1 is initiated after the NYISO Board of Directors (Board) approves the Comprehensive Reliability Plan (CRP). In Phase 1, the NYISO, in collaboration with its stakeholders and other interested parties, develops a ten-year projection of congestion and together with historic congestion identifies, ranks and groups the most congested elements on the New York bulk power system. For the top three congested elements or groupings, studies are performed which include: (a) the development of three types of generic solutions to mitigate the identified congestion; (b) a benefit/cost assessment of each solution based on NYCA-wide production cost savings; and (c) presentation of additional metrics for informational purposes. The three types of generic solutions are transmission, generation and demand response. Scenario analyses are also performed to help identify factors that increase or produce congestion in the CARIS base case.

Phase 1 results were presented in a written draft report to the NYISO's Electric System Planning Working Group (ESPWG) and the Transmission Planning Advisory Subcommittee (TPAS) for review. After that review, the draft report was presented to the NYISO's Business Issues Committee (BIC) and the Management Committee (MC) for discussion and action before it was submitted to the Board for approval.

This final report presents the 2011 CARIS Phase 1 study results and provides objective information on the nature of congestion in the New York Control Area (NYCA). Developers can use this information to decide whether to proceed with transmission upgrades or other resource additions (generation or demand response). This report does not make recommendations for specific projects, and does not advocate any type of resource addition or other actions.

Developers may also propose economic transmission projects for regulated cost recovery under the NYISO's Tariff and proceed through, the Project Phase, CARIS Phase 2, which will be conducted by the NYISO upon request by a developer. For such a transmission project, the NYISO will determine whether it qualifies for regulated cost recovery under the Tariff. A developer of a qualified economic transmission project may elect to pursue regulated cost recovery under the NYISO's Tariff. Under CARIS , a regulated economic transmission project must be approved by at least 80% of the weighted vote cast by New York's Load Serving Entities (LSEs) that serve loads in zones that the NYISO identifies as beneficiaries of the transmission project. The beneficiaries are those load zones that experience net benefits

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[1] The NYISO began reporting NYISO historic congestion information in 2003.

measured over the first ten years from the proposed project commercial operation date. These regulated economic transmission projects receive cost recovery from these beneficiaries through the NYISO Tariff provisions once they are placed in service. Developers of economic generation or demand response projects may choose to pursue such projects on a merchant basis, or to enter into contracts with LSEs or other parties.

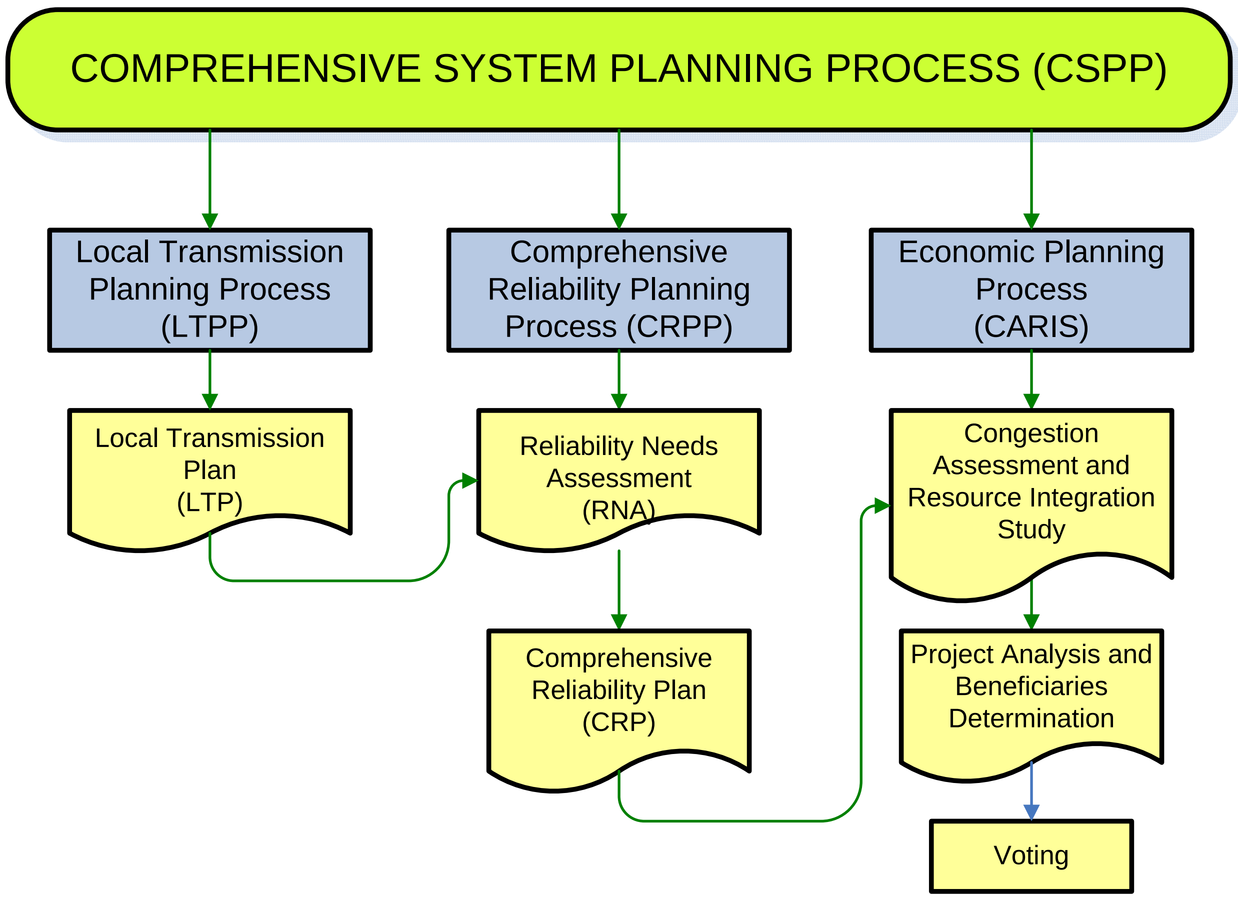

Figure 1-1: NYISO Comprehensive System Planning Process

The projected congestion in this report may be different than actual congestion experienced in the future. CARIS simulations are based upon a limited set of long term assumptions for modeling of grid resources throughout the ten-year planning horizon. A range of costs is used for the benefit/cost ratios developed for generic projects for each type of generic solution, and are intended for illustrative purposes only.

2. Background

2.1. CARIS Process

The objectives of the CARIS economic planning process are to:

a. Provide projections of future congestion on the New York State bulk power transmission facilities over the ten-year CSPP planning horizon;

b. Identify, through the development of appropriate scenarios, factors that might cause or increase congestion;

c. Provide information to market participants, stakeholders and other interested parties on solutions to reduce congestion;

d. Provide an opportunity for developers to propose solutions that may reduce the congestion; and

e. Provide a process for the evaluation and approval of regulated economic transmission projects for regulated cost recovery under the NYISO Tariff.

These objectives are achieved through the two phases of the CARIS process which are graphically depicted in Figure 2-1 below.

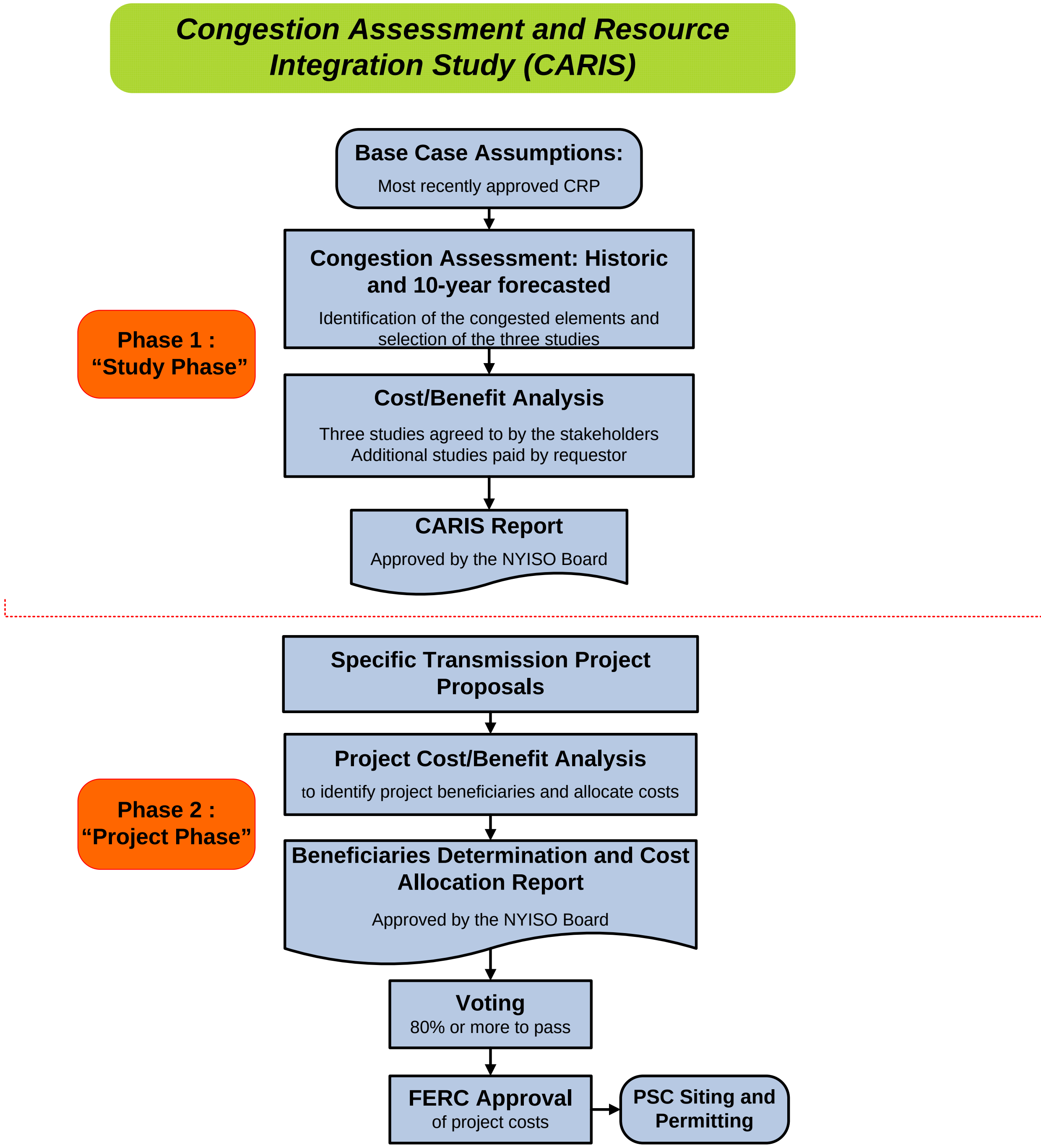

Figure 2-1: Overall CARIS Diagram

2.1.1. Phase 1 - Study Phase

In Phase 1 of the CARIS process, the NYISO, in collaboration with market participants, identifies the most congested elements in the New York bulk power system and determines the three studies. In identifying the most congested elements, the NYISO performs both a five-year historic and a ten-year forward-looking congestion assessment to identify the seven most congested elements and, through a relaxation process, develops potential groupings and rankings based on the highest production cost savings resulting from the relaxation. The top three ranked elements or groupings become the subjects of the three CARIS studies. For each of these three studies the NYISO conducted a benefit/cost analysis of generic solutions. All resource types - generation, transmission and demand response - are considered on a comparable basis as generic solutions to congestion. The solutions analyzed are not specific projects, but rather represent generic transmission, demand response and generation resources placed individually in the congested locations on the system to measure their effects on relieving each of the three most congested elements and the resulting economic benefits.

The principal metric for measuring the economic benefits for each generic solution is the NYCA-wide production cost savings that would result from each generic solution, expressed as the present value over the ten-year planning horizon. The CARIS report also presents data on additional metrics, including estimates of reductions in losses, changes in Locational Based Marginal Pricing (LBMP) load payments, generator payments, changes in installed capacity costs, changes in emissions costs and changes in payments for Transmission Congestion Contracts (TCCs). The TCC payment metric in Phase 1 is simplified to include congestion rent calculations only and is different from the TCC revenue metric contained in Phase 2. The Installed Capacity (ICAP) metric calculation was changed after the 2009 CARIS Phase 1. CARIS metrics are described in more detail in Section 3.

2.1.2. Phase 2 – Project Phase

The Phase 2 model will be developed from the CARIS 1 database using an assumption matrix developed after discussion with ESPWG and will reflect all necessary system modeling changes required for a 10 year extension. Updating and extending the CARIS database for Phase 2 of the CARIS is conducted after the approval of the CARIS Phase 1 report by the NYISO Board.

Potential economic transmission projects that have an estimated capital cost in excess of $25 million may seek regulated cost recovery through the NYISO Tariff. Such developers must submit their projects to the NYISO for a benefit/cost analysis in accordance with the Tariff. The costs for the benefit/cost analysis will be supplied by the developer of the project as required by the tariff. Projects are eligible for regulated cost recovery if the present value of the benefits exceeds the present value of the costs over the first ten years of the project life; and the present value over the first ten years of LBMP load savings, net of TCC revenues and bilateral contract quantities, must be greater than the present value of the projected project cost revenue requirements for the first ten years of the amortization period.

Beneficiaries will be LSEs in load zones determined to benefit economically from the project, and cost allocation among load zones will be based upon their relative economic benefit. The beneficiary determination for cost allocation purposes will be based upon each zone's net LBMP load savings. The net LBMP load savings are determined by adjusting the LBMP load savings to account for TCC revenues and bilateral contract quantities; all entities in the zones with positive net LBMP load savings are considered to be beneficiaries. The net LBMP load savings produced by a project over the first ten years of commercial operation will be measured and compared on a net present value basis with the project's revenue requirements over the same first ten years of a project's life measured from its expected in-service date. LSE costs within a zone will be allocated according to the ratio of its load to all load in the zone - both expressed in MWh.

In addition to the NYCA-wide production cost savings metric and the net LBMP load savings metric, the NYISO will also provide additional metrics, for information purposes only, to estimate the potential benefits of the proposed project and to allow LSEs to consider other metrics when evaluating or comparing potential projects. These additional metrics will include estimates of reductions in losses, changes in LBMP load payments, changes in generator payments, changes in Installed Capacity (ICAP) costs, changes in emissions costs, and changes in TCC revenues. The TCC revenue metric that will be used in Phase 2 of the CARIS process is different from the TCC payment metric used in Phase 1. In Phase 2, the TCC revenue metric will measure reductions in estimated TCC revenues and allocation of congestion rents to the TOs (for more detail on this metric see Section 3.2.2 of this report and the CSPP Manual.[2]).

The NYISO will also analyze and present additional information by conducting scenario analyses, at the request of the developer and ESPWG where appropriate, regarding future uncertainties, such as possible changes in load forecasts, fuel prices and environmental regulations, as well as other qualitative impacts, such as improved system operations, other environmental impacts, and integration of renewable or other resources. Although this data may assist and influence how a benefiting LSE votes on a project, it will not be used for purposes of cost allocation.

The NYISO will provide its benefit/cost analysis and beneficiary determination for particular projects to the ESPWG for comment. Following that review, the NYISO benefit/cost analysis and beneficiary determination will be forwarded to the BIC and MC for discussion and action. After the MC vote, the benefit/cost analysis and beneficiary determination will be forwarded to the NYISO Board of Directors for review and approval.

After the project benefit/cost and beneficiary determinations are approved by the NYISO Board and posted on the NYISO's website, the project will be brought to a special meeting of the beneficiary LSEs for an approval vote, utilizing the approved voting procedure (see Section 1.2.5 of the Initial CARIS Manual, Appendix F). The specific provisions for cost allocation are set forth in the Tariff. In order for a project to be approved for regulated cost recovery, the Tariff states that "eighty (80) percent or more of the actual votes cast on a weighted basis must be cast in favor of implementing the project." If the project meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project through the NYISO Tariff. This process will not relieve the developer of the responsibility to file with FERC for

[2] http://www.nyiso.com/public/webdocs/services/planning/initial_caris_manual_bic_approved/CARISmanual.pdf. The planning Manuals are currently under revision and will be released as a CSPP Manual.

approval of the project costs and with the appropriate state authorities to obtain siting approval for the project.

3. CARIS Methodology and Metrics

3.1. CARIS Methodology

For the purposes of conducting the ten-year forward looking CARIS analysis, the NYISO, in conjunction with ESPWG, developed a production costing model database and utilized GE's Multi-Area Production Simulation (MAPS) software. The details and assumptions in developing this database are summarized in Appendix C.

The Portfolio Ownership and Bid Evaluation (PROBE) production cost simulation tool, developed by PowerGEM LCC, has been used for the last seven years to perform the NYISO historic congestion analysis. PROBE utilizes the actual NYISO Day-Ahead Market (DAM) data to emulate the actual security constrained unit commitment (SCUC) operation. MAPS utilizes the most recent five years of historic data. Unlike MAPS simulation, PROBE simulates virtual bidding and transmission outages and calculates production costs based on generation mitigated bids. While those additional attributes are important in capturing the real congestion costs for the past events, it is nearly impossible to model them with certainty in projecting future transmission congestion. Therefore, these attributes are not accounted for in the ten-year forward looking CARIS analysis. Actual future congestion will vary from projections depending on a number of factors. For more detail see Appendix D.

3.2. CARIS Metrics

The principal benefit metric for CARIS analysis is NYCA-wide production cost reduction that would result from each of the generic solutions. Additional benefit metrics were analyzed as well, and the results are presented in this report and accompanying appendices for information purposes only. All benefit metrics were determined by measuring the difference between the projected CARIS base case system value and a projected system value when each generic solution was added. The discount rate used for the present value analysis was the current weighted average cost of capital for the NYTOs, weighted by their annual GWh send-out in 2010.

One of the key metrics in the CARIS analysis is termed Demand Dollar congestion (expressed as Demand$ congestion in PROBE). Demand$ congestion for a constraint is the amount of congestion paid by load throughout NYCA as a result of that constraint. The Demand$ congestion cost is the product of the constraint shadow price and the NYCA load zone shift factor (SF) on that constraint. This definition is consistent with the definition that has been used for the reporting of historic congestion for the past seven years. Demand$ congestion is used to identify and rank the significant transmission constraints as candidates for grouping and the evaluation of potential generic solutions. It does not equate to payments by load.

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3.2.1. Principal Benefit Metric[3]

The principal benefit metric for the CARIS analysis is the present value of the NYCA-wide production cost reduction that would result from implementation of the generic congestion mitigation solutions. The NYCA-wide production cost savings are calculated as those savings associated with generation resources in the NYCA and the costs of incremental imports/exports priced at external proxy generator buses of the solution case. This is an improvement to the 2009 CARIS where the NYCA-wide production cost savings were calculated as those savings associated with generation resources in the NYCA and the costs of net total interface flows priced at the external proxy generator buses.

Specifically, the NYCA-wide production cost savings are calculated using the following formula:

NYCA-wideNYCA-wide Production Cost Savings = NYCA Generator Production Cost Savings -

$$\sum \sum [(Import/Export\ FIow)_{Solution} - (Import/Export\ Flow)_{Base}] \times ProxyLMP_{Solution}$$

Where $ProxyLMP_{Solution}$ is the LMP at one of the external proxy buses;
$(Import/Export\ FIow)_{Solution} - (Import/Export\ Flow)_{Base}$ represents incremental imports/exports with respect to one of the external systems;
and the summations are made for each external area and all simulated hours.

3.2.2. Additional Benefit Metrics

The additional benefits, which are provided for information purposes only, include estimates of reduction in loss payments, LBMP load costs, generator payments, ICAP costs, emission costs, and TCC payments. All the quantities, except ICAP, will be the result of the forward looking production cost simulation for the ten-year planning period. The NYISO, in collaboration with the ESPWG, determined the methodology and models needed to develop and implement these additional metrics requirements, which are described below and detailed in the Initial CARIS Manual. An example illustrating the relationship among some of these metrics is provided in Appendix E.

Reduction in Losses – This metric calculates the change in marginal losses payments. Losses payments are based upon the loss component of the zonal LBMP load payments.

LBMP Load Costs – This metric measures the change in total load payments. Total load payments include the LBMP payments (energy, congestion and losses) paid by electricity demand (load, exports, and wheeling). Exports will be consistent with the input assumptions for each neighboring control area.

[3] Section 31.3.1.3.4 of the Tariff specifies the principal benefit metric for the CARIS analysis.

Generator Payments – This metric measures the change in generation payments and includes the LBMP payments (energy, congestion, losses), and ancillary services payments made to electricity suppliers. Generator payments are calculated as the sum of the LBMP payments to generators and imports. Imports will be consistent with the input assumptions for each neighboring control area.

ICAP Costs –The latest available information from the installed reserve margin (IRM), locational capacity requirement (LCR), and ICAP Demand Curves are used for the calculation. The NYISO first calculates the NYCA MW impact of the generic solution on LOLE. The NYISO then forecasts the installed capacity cost per megawatt-year point on the ICAP demand curves in Rest of State and in each locality for each planning year. There are two variants for calculating this metric, both based on the MW impact. For more detail on this metric see the Section 31.3.1.3.5.6 of the Tariff.

Emission Costs – This metric measures the change in the total cost of emission allowances for CO_2, NO_X, and SO_2, emissions on a zonal basis. Total emission costs are reported separately from the production costs. Emission costs are the product of forecasted total emissions and forecasted allowance prices.

TCC Payments – The TCC payment metric is calculated differently for Phase 1 and for Phase 2 of the CARIS process, as described in the NYISO tariff. As was done for the 2009 CARIS, the TCC payment metric was simplified to calculate changes in congestion rents.

4. Baseline System Assumptions

The implementation of the CARIS process requires the gathering, assembling, and coordination of a significant amount of data, in addition to that already developed for the reliability planning processes. The 2011 CARIS analysis began with the base case input assumptions provided in the 2010 CRP and aligns with the ten-year reliability planning horizon for the 2010 CRP.

4.1. Major System Assumptions

The base case has been updated for this CARIS Phase 1 using the assumptions provided below. These assumptions were discussed with the stakeholders at several meetings of the ESPWG. Appendix C includes a detailed description of the assumptions utilized in the CARIS analysis. The key assumptions are presented below:

1. Power flow models – the 2010 CRP power flow base cases were updated for use in the 2011 CARIS study.

2. The load and capacity forecast was developed from the 2011 Gold Book. It represents the baseline forecast for energy and peak demand by zone for the ten year study period.

3. The transmission and constraint model utilizes a bulk power system representation for the entire Eastern Interconnection. The model uses both the 2010 RNA/CRP transfer limits and actual operating limits.

4. The production cost model performs a security constrained economic dispatch of generation resources to serve the load. The production cost curves, unit heat rates, fuel forecasts and emission costs forecast were developed from multiple data sets including public domain information, proprietary forecasts and confidential market information. The model includes scheduled generation maintenance periods based on a combination of the unit's planned and forced outage rates.

5. Other specific modeling improvements over the 2009 CARIS were made to conform the ConEd/ PSEG wheel with FERC Orders, to the operation of the Ramapo PAR, the utilization of more representative Central East operating limits, the use of a more refined fuel price forecast (monthly to weekly), flat dispatch hurdle rates between regions over the 10 years, and the use of better combined cycle and gas turbine model representations.

Notwithstanding the other major inputs listed in other sections that can have significant impacts on the congestion projection, there are known events that have impacts on the simulation outcome, as summarized in Table 4-1.

Table 4-1: Timeline of Major Changes

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
M29 Cable Installed	Bayonne Generator Installed (500 MW)	Susquehanna-Roseland Line Installed	Nine Mile Pt2 Uprate (53 MW)						
Athens SPS Removed*	Nine Mile Pt2 Uprate (115 MW)	HTP Installed	Munnsville Wind Power Uprate (0.6 MW)						
Steel Winds II Installed (1.5 MW)	Ontario Uprate (5.6 MW)								
Astoria Energy II Installed (576 MW)									
Energy Systems North East Retired (79.4 MW)**									
Project Orange 1&2 Retired (40 MW)**									
Greenidge 4 Retired (106.1 MW)									
Westover 8 Retired (81.2 MW)									

* The CARIS base case assumes, for study purposes, that the Athens SPS will no longer be in service starting in January, 2011.
** Units retired in 2010

4.2. Load and Capacity Forecast

The load and capacity forecast used in the CARIS base case, provided in Table 4-2, was based on the 2011 Gold Book and accounts for the impact of programs such as the Energy Efficiency Portfolio Standard (EEPS).

Table 4-2: CARIS 1 Base Case Load and Resource Table [4]

Year		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Peak Load (MW)											
	NYCA	32,712	33,182	33,433	33,609	33,678	33,749	33,916	34,190	34,533	34,867
	Zone J	11,505	11,635	11,720	11,785	11,830	11,880	12,015	12,200	12,405	12,585
	Zone K	5,364	5,470	5,520	5,543	5,572	5,633	5,655	5,721	5,775	5,845
Resources (MW)											
	Capacity	40,106	40,865	40,860	40,863	40,863	40,863	40,863	40,863	40,863	40,863
NYCA	SCR	2,053	2,053	2,053	2,053	2,053	2,053	2,053	2,053	2,053	2,053
	Total	**42,159**	**42,918**	**42,913**	**42,916**	**42,916**	**42,916**	**42,916**	**42,916**	**42,916**	**42,916**
	Capacity	9,667	10,167	10,167	10,167	10,167	10,167	10,167	10,167	10,167	10,167
Zone J	SCR	476	476	476	476	476	476	476	476	476	476
	Total	**10,143**	**10,643**	**10,643**	**10,643**	**10,643**	**10,643**	**10,643**	**10,643**	**10,643**	**10,643**
	Capacity	5,549	5,549	5,549	5,549	5,549	5,549	5,549	5,549	5,549	5,549
Zone K	SCR	154	154	154	154	154	154	154	154	154	154
	Total	**5,703**	**5,703**	**5,703**	**5,703**	**5,703**	**5,703**	**5,703**	**5,703**	**5,703**	**5,703**

Source: 2011 Gold Book

4.3. Transmission Model

The CARIS production cost analysis utilizes a bulk power system representation for the entire Eastern Interconnection, which is defined roughly as the bulk electric network in the United States and Canadian Provinces East of the Rocky Mountains, excluding WECC and Texas. Figure 4-1 below illustrates the Regions and Balancing Authorities in the CARIS model. The CARIS model includes a full active representation for the NYCA, ISO-NE, IESO, and PJM.

[4] New York Control Area (NYCA) "Capacity" values include resources internal to New York, additions (South Pier generator addition is not included), re-ratings, retirements, purchases and sales, and UDRs with firm capacity. Zones J and K capacity values do not include UDRs with firm capacity.

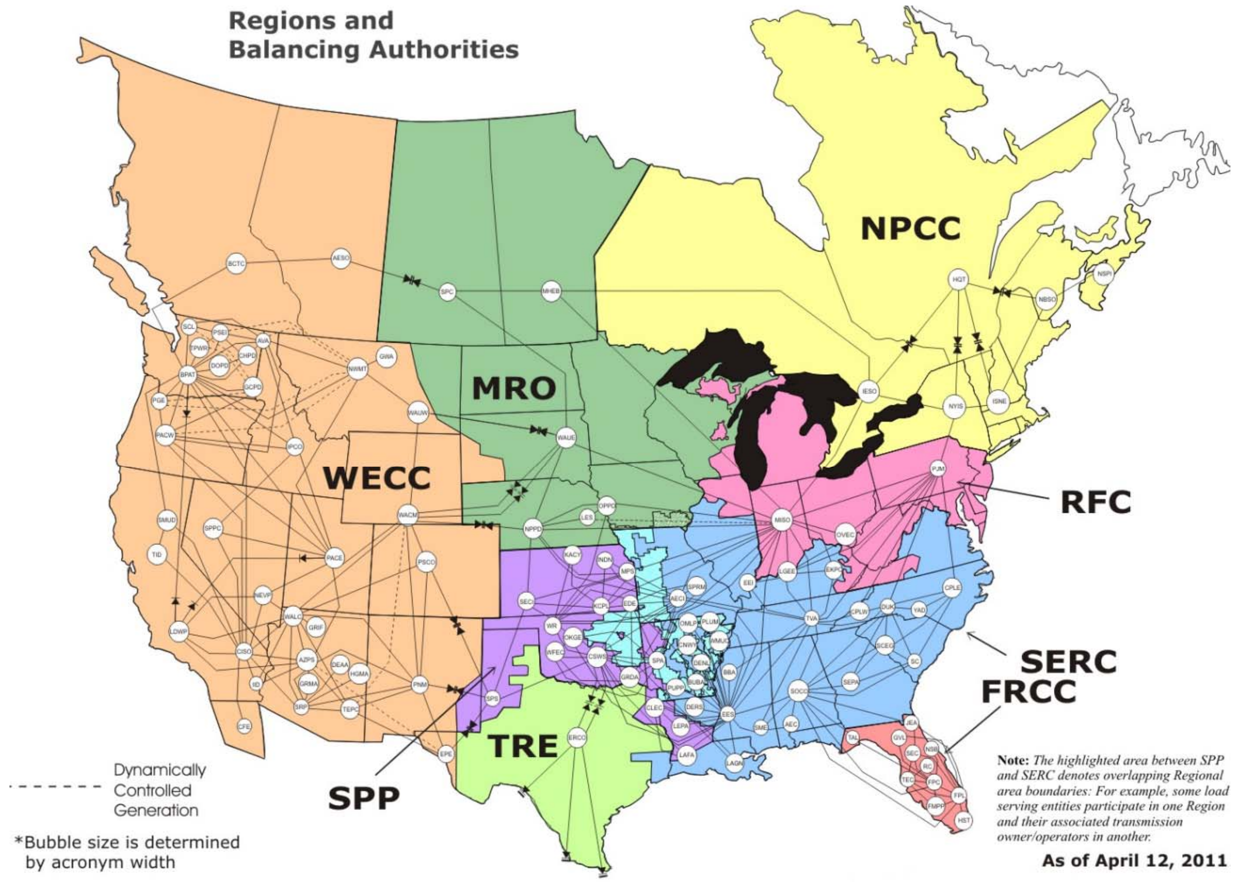


Figure 4-1: Areas Modeled in CARIS (Excluding WECC & TRE)

Source: NERC

4.3.1. New York Control Area Transfer Limits

Unlike the RNA and CRP, which utilize emergency limits, the CARIS study utilizes normal transfer limits and actual facility ratings. For New York Control Area Interface Transfer limits, the limits are consistent with the SCUC operating limits and operating nomograms with some exceptions as indicated in Table 4-3 below.

Table 4-3: Transmission System Normal Voltage Transfer Limits for Key Interfaces (in MW)

Interface	2011 CARIS Study
WEST CENTRAL-Open	2150
CENTRAL EAST	2400
ConEd - Long Island	2166
Dunwoodie (I) to NYCity (J)	4000
Dunwoodie (I) to Long Island (J)	1217
Sprainbrook/Dunwoodie South	5315

Note: Central East was modeled wit a unit sensitive nomogram reflective of the operating nomogram.

Normal thermal interface transfer limits for the CARIS study are not directly utilized from the thermal transfer analysis performed using the Power Technologies Inc. Power System Simulator for Engineering (PSS/E) Managing and Utilizing System Transmission (MUST) software application, which uses the transmission planning set of design criteria contingencies. Instead, CARIS uses monitored line and contingency sets identified from MUST analysis as the most limiting constraint to the NYCA cross-state transmission interfaces to determine thermal transfer limits as the load and generation is varied throughout the annual simulations. The resulting monitored lines and contingency sets used in the CARIS do not include lines that have less than a 5% impact on the NYCA cross-state transmission interfaces, or the lines that only impact local 115-138 kV transmission or sub-transmission constraints.

4.4. Fuel Forecasts

4.4.1. CARIS Base Annual Forecast

The fuel price forecasts for CARIS are based on the U.S. Energy Information Administration's (EIA)[5] current national long-term forecast of delivered fuel prices, which is released each spring as part of the Annual Energy Outlook (AEO). The figures in this forecast are in real dollars (i.e., indexed relative to a base year). Forecasted time-series of the GDP deflator published by EIA, as part of the AEO, were used to inflate the *real* values to *nominal* values. This forecast is updated quarterly based on data published in EIA's periodic Short-Term Energy Outlooks.

4.4.2. New York Fuel Forecast

In developing the New York fuel forecast, adjustments were made to the EIA fuel forecast to reflect bases for fuel prices in New York. A key source of data for estimating the

[5] www.eia.doe.gov

relative differences or 'basis' for fuel prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on information collected through Form EIA-923.[6] The base annual forecast series are then subjected to an adjustment to reflect the New York 'basis' relative to the national prices as described below.

Natural Gas

Analysis of EIA's Short-Term Energy Outlooks from the past two years for the national average of delivered price of natural gas for electricity generation suggests that it is, on average, 10% higher than Henry Hub prices. The regional basis is then assessed against 110% of Henry Hub prices. The natural gas price for Downstate (Zones J and K), is the Transco Zone 6 (New York) hub-price[7] and for Upstate (Zones A through I) the proxy-hub is the Tetco-M3. As of September 2011, the forecasted Downstate natural gas price is roughly 17% higher relative to the national average, and the Upstate natural gas price is 10% higher than the national average. Forecasted fuel prices for Upstate and Downstate New York are shown in Figures 4-2 and 4-3.

Fuel Oil

Based on EIA data in Electric Power Monthly, price differentials across states and localities can be explained by a combination of transportation/delivery charges and taxes. According to Electric Power Monthly, the trend of fuel-oil prices for New York implies that, on average, they are 5% below the national average delivered price. Based on this, the basis for both distillate and residual oils for Downstate are 0.95 (relative to the national average). The Upstate basis is 0.98 to reflect the additional transportation costs. For illustrative purposes, forecasted prices for Distillate Oil (Fuel Oil #2) and for Residual Oil (Fuel Oil #6) are shown in Figures 4-2 and 4-3.

Coal

The data from Electric Power Monthly for the average cost of coal delivered for electricity generation was used to calculate a common basis for all NYCA Zones. Prices in New York are, on average, 40% higher than in the United States as a whole. (The published figures do not make a distinction between the different varieties of coal; *i.e.*, bituminous, sub-bituminous, lignite, etc.), EIA's 2011 AEO forecast is used for CARIS.

4.4.3. Seasonality and Volatility

All average monthly fuel prices, with the exception of coal and uranium, display somewhat predictable patterns of fluctuations over a given 12-month period. In order to capture such seasonality, NYISO estimated seasonal-factors using standard statistical methods.[8] The

[6] Prior to 2008, this data was submitted via FERC Form 423. 2008 onwards, the same data are collected on Schedule 2 of the new Form EIA-923. See http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html . These figures are published in Electric Power Monthly.

[7] The raw hub-price is 'burdened' by an appropriate level of local taxes.

[8] This is a two-step process: First, deviations around a centered 12-month moving average were calculated over the 2005-2010 period; second, the average values of these deviations were normalized to estimate monthly/seasonal factors.

multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

The data used to estimate the seasonal factors are as follows:

- Natural Gas: Raw daily prices from ICE (Intercontinental Exchange) for the trading hubs Transco Zone 6 (New York) - as a proxy for Downstate (Zones J and K) – Tetco-M3 – as a proxy for Upstate (Zones A to I).

- Fuel Oils #2 and #6: The average daily prices from Argus, Bloomberg, and Platts.

The seasonalized time-series represents the forecasted trend of average monthly prices. However, in order to facilitate simulation studies to explore scenarios with higher/lower prices, the NYISO developed volatility-measures to capture variability of average monthly prices. For each regional fuel price, this measure was one standard deviation of the basis.

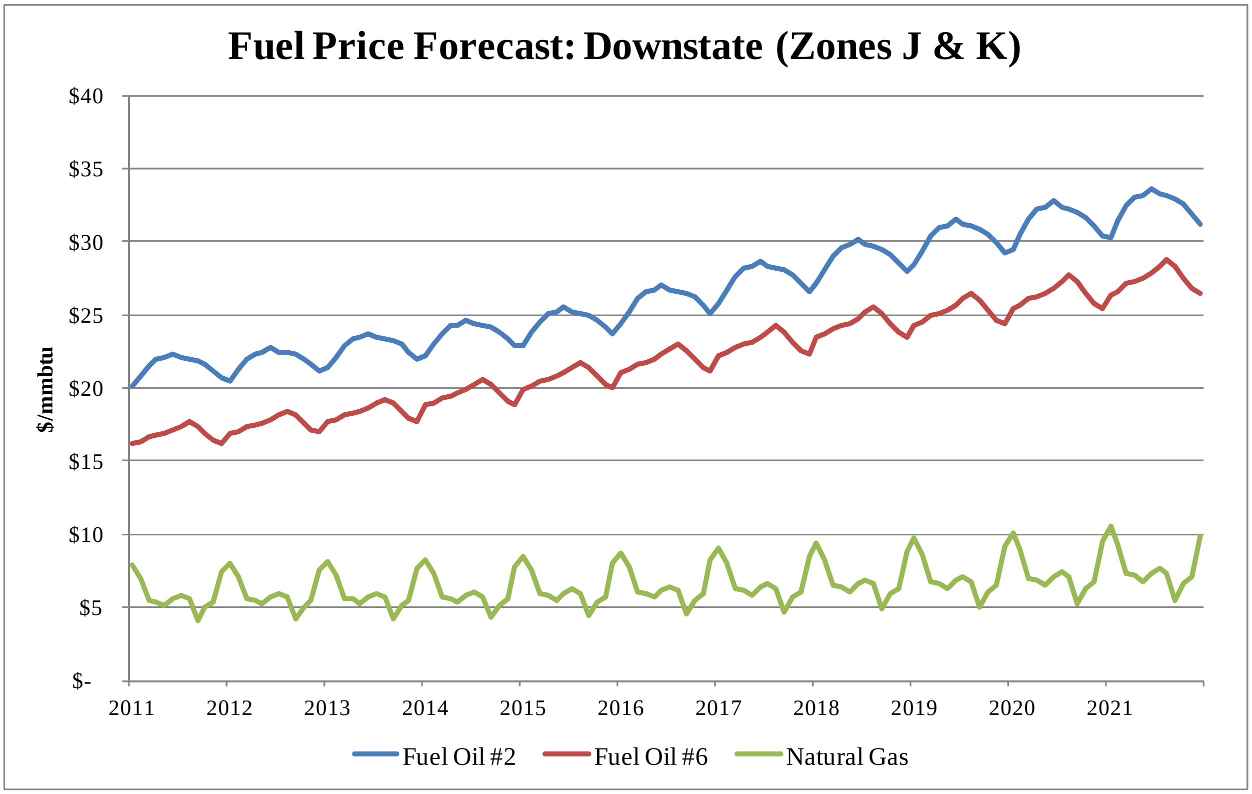


Figure 4-2: Forecasted fuel prices for Zones J & K (nominal $)

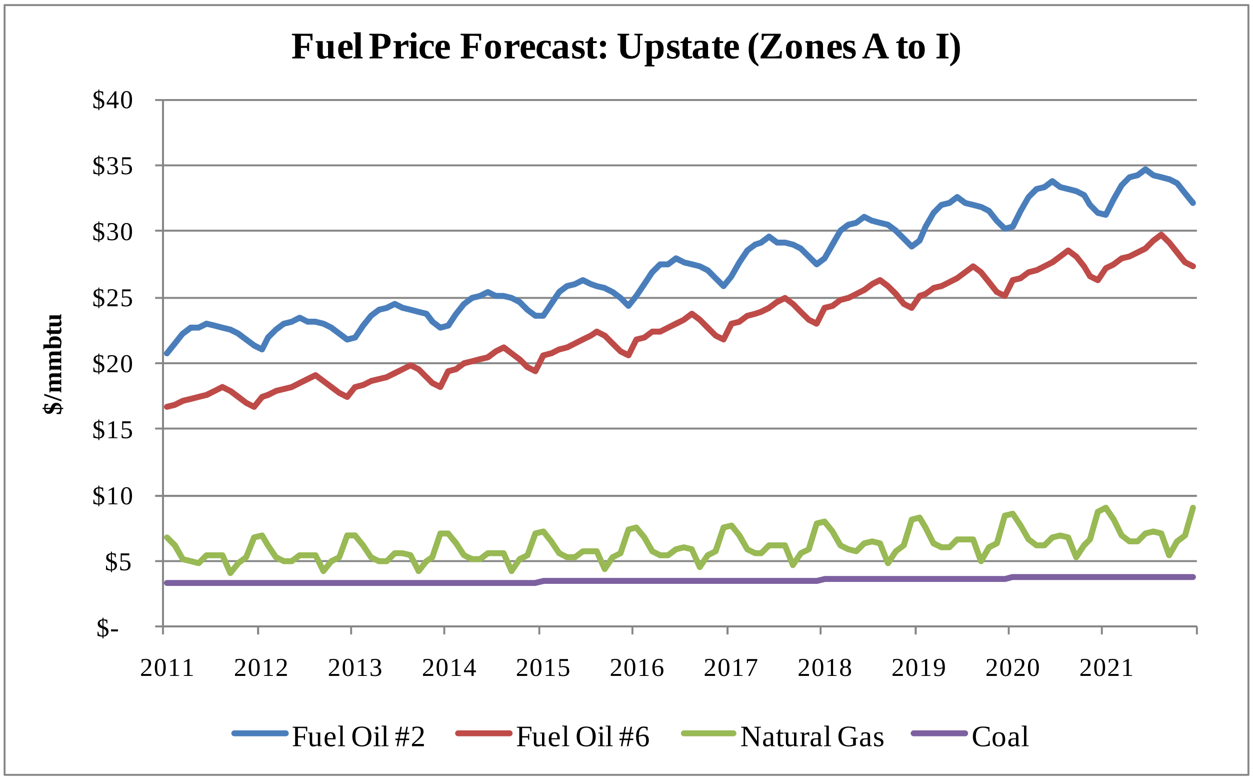


Figure 4-3: Forecasted fuel prices for Zones A-I (nominal $)

4.4.4. External Areas Fuel Forecast

The fuel forecasts for the three external areas, ISO-NE, PJM, and IESO, were also developed. For each of the fuels, the basis for ISO-NE, PJM-East, and PJM-West were based on the state level data published in Electric Power Monthly. With respect to IESO, the relative prices were based on data from a recent publication.[9]

4.5. Emission Cost Forecast

The costs of emission allowances are an increasing portion of generator production costs. Currently, all NYCA fossil fueled generators greater than 25 MW and most generators in most surrounding states are required to hold allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2. There are exchanges for trading allowances and futures contracts for allowances. The Chicago Climate Futures Exchange (CCFE) offers standardized and cleared futures and options contracts on emission allowances and other environmental products. Until mid 2010, there was a robust market for the exchange of these allowances. When the USEPA proposed the revised Clean Air Interstate Rule (CAIR), called the Clean Air Transport Rule (CATR), the proposal called for the end of the use of the CAIR allowances. The effect of this proposal was to place holders of these allowances in the position of "use them or lose them". Generators who had

[9] Ontario Wholesale Electricity Market Price Forecast For the Period May 1, 2008 through October 31, 2009, Presented to Ontario Energy Board, April 11, 2008 by Navigant Consulting Inc., Toronto, Ontario.

been banking allowances then sought to reclaim the remaining value by seeking buyers at all time minimum prices. As a consequence, the market prices were no longer a reliable benchmark for estimating the cost of future emissions.

Emission allowance price forecasts for SO_2 and NOx were developed by estimating the cost of removal from the operation of existing emission control equipment for 2011.

In July 2011, the USEPA replaced the Clean Air Transport Rule proposal with the finalized Cross-State Air Pollution Rule (CSAPR) that requires significant additional reductions of SO_2 and NOx emissions beyond those previously identified. Due to the timing of this rule and the numerous unanswered questions surrounding it, a decision was made with the support of the ESPWG not to incorporate the rule in the 2011 CARIS 1 study. However, the impact of the CSAPR, together with its technical adjustments made by EPA in Oct 2011, is analyzed as a scenario in the report.

The CSAPR establishes a new allowance allocation and trading system for units larger than 25 MW of nameplate capacity. To demonstrate compliance with the rule, affected generators will need one allowance for each ton emitted in a year. In New York, CSAPR will affect 167 units that represent 23,275 MW of capacity. The first emission reductions start in 2012 with additional reductions required in 2014. These additional emission reductions are anticipated to apply in 2012 and 2013 and will be accompanied by increased costs from fuel switching and more aggressive operation of existing emission control equipment. In 2014, additional limitations will become effective for NOx RACT and BART as well as the initiation of the CSAPR Assurance Level provisions. These limits are expected to increase the cost of removal of NOx.

The RGGI program for capping CO_2 emissions from power plants in ten Northeastern states (NJ was not included in RGGI in our model) has been in effect since 2009. Experience to date has shown the program to be oversupplied with CO_2 allowances. The price forecast is near the floor for 2011. The program is currently being evaluated with a possible goal of reducing the cap and thereby increasing the prices. The working assumption for this study is the initiation of a federal CO_2 program in 2016. Until then the RGGI program will be redesigned to increase prices to match the federal program when it becomes effective.

Emission costs, which are driven by the fuel burned, the efficiency of the unit and the emission control technology employed, are calculated as the product of emission rate and emission allowance costs. Annual emission rates were used in the simulations. The annual emission rates in terms of Ton/mmBTU are available from the EPA's Clean Air Markets Division (CAMD). Since the emission rate determined above is an average emission rate, the same rate was used across the operating range.

Figure 4-4 shows the emission allowance forecast by year in $/Ton.

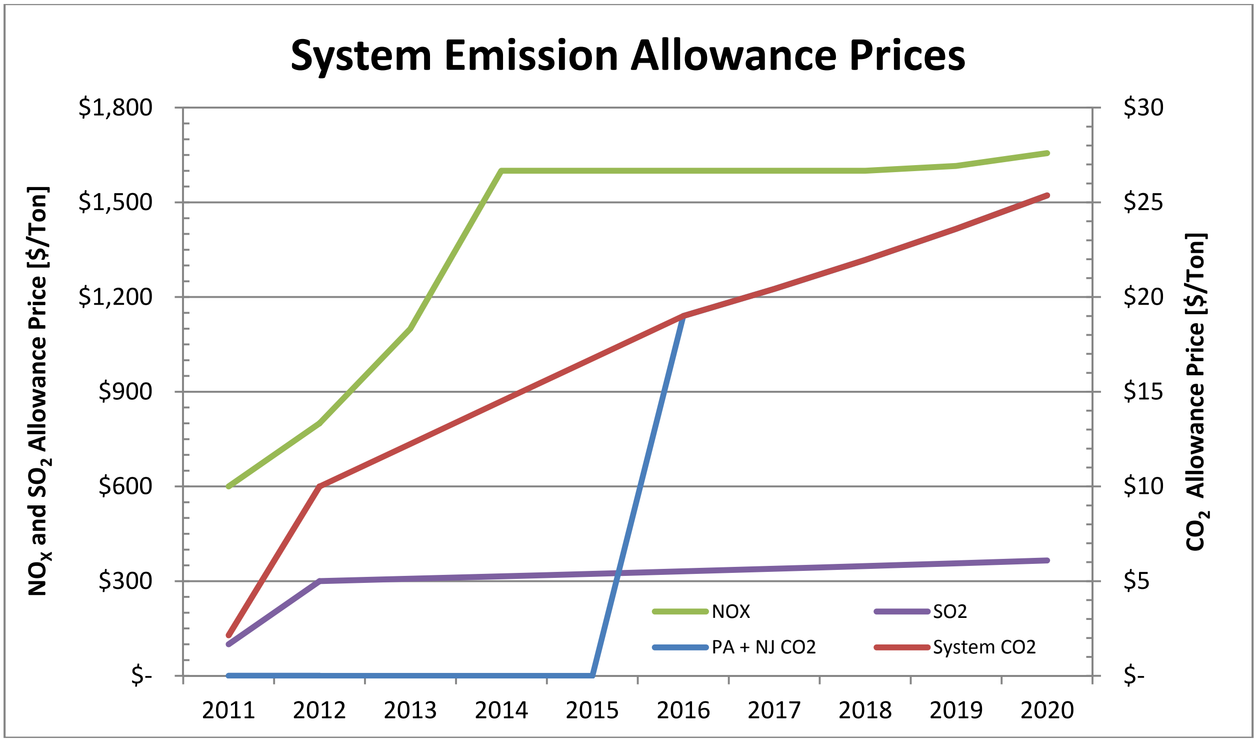


Figure 4-4: Emission Allowance Forecast

With respect to the carbon emission futures under the Regional Greenhouse Gas Initiative (RGGI), the data from the CCFE was available only through 2012. The implied trend was extrapolated to cover the 2013-2020 study period.

4.6. Generic Solutions

Generic solutions are evaluated by NYISO for each of the three CARIS studies utilizing each resource type (generation, transmission, and demand response) as required in Section 31.3.1.3 of the Tariff. The development of the generic solution representative costs was based on available public information with stakeholder input. This methodology utilized typical MW block size generic solutions, a standard set of assumptions without determining actual project feasibility, and order of magnitude costs for each resource type.

The cost estimates for generic solutions are utilized to develop order of magnitude costs for Benefit/Cost ratio analysis. These estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these estimated costs.

4.6.1. Resource Block Sizes

Typical resource block sizes are developed for each resource type based on the following guidelines:

- Block size would be reflective of a typical size built for the specific resource type and geographic location;

- Block size is to be small enough to be additive with reasonable step changes; and
- Blocks sizes are in comparable proportions between the resource types.

The block sizes selected for each resource type are presented in Table 4-4 through Table 4-6.

Table 4-4: Transmission Block Sizes

Location	Line System Voltage (kV)	Block Capacity (MVA)
Zone A-J	345	1000
Zone K	138	500

Note: 138 kV was selected for Zone K due to the limited number of 345 kV substations located within this Zone. The block capacity was selected so as to be reflective of the typical line size for this voltage class and location.

Table 4-5: Generation Block Sizes

Plant Location	Plant Block Size Capacity (MW)
Zone A-K	500

Table 4-6: Demand Response (Each 200 MW Block contains DR+EE)

Location	Demand Response Quantity (MW)	Portfolio Type
Zone A-K	100	Energy Efficiency
Zone A-K	100	Demand Response

4.6.2. Guidelines and Assumptions for Generic Solutions

Developing cost estimates for these resource types is dependent on many different parameters and assumptions. A detailed list of assumptions utilized for each resource is included in the Generic Solution Cost Matrix, in Appendix C.

The following guidelines and assumptions are used to select the generic solution:

Transmission Resource

- The generic transmission solution consists of a new transmission line interconnected to the system upstream and downstream of the grouped congested elements being studied.
- The generic transmission line terminates at the nearest existing substations of the grouped congested elements.
- If there is more than one substation located near the grouped congested elements which meets the required criteria, then the two substations that have the shortest distance between the two are selected.

Generation Resource

- The generic generation solution consists of the construction of a new combined cycle generating plant connecting downstream from the grouped congested elements being studied.
- The generic generation solution terminates at the nearest existing substation of the grouped congested elements.
- If there is more than one substation located near the grouped congested elements which meets the required criteria, the substation that has the highest relative shift factor is selected.

Demand Response

- The generic demand response solution is modeled as a reduction in load within the zone where the most downstream grouped congested element is terminated.
- The on-peak demand is assumed to be concentrated in the top 60-100 highest load hours.
- The demand response installed in a zone is limited to less than 10% of the peak zonal load. If the modeled demand response exceeds 10% of the peak zonal load, it is prorated based on peak load between the selected zone and the next downstream zone.

4.6.3. Generic Solution Pricing Considerations

Three sets of costs were developed that are reflective of the differences in labor, land and permitting costs among Upstate, Downstate and Long Island. The considerations used for estimating costs for the three resource types and for each geographical area are listed in Table 4-7.

Table 4-7: Generic Solution Pricing Considerations

Transmission	Generation	Demand Response
Transmission Line Cost per Mile	Plant Costs	Energy Efficiency Programs
Substation Terminal Costs	Generator Lead Cost per Mile	Demand Response Programs
System Upgrade Facilities	Substation Terminal Costs	
	System Upgrade Facilities	
	Gas Line Cost per Mile	
	Gas Regulator Station	

All costs were reviewed through the stakeholder process. As part of this process, ranges for the costs for each element were developed in order to address the wide variability that can occur in a project due to such items as permitting, right of way constraints, and existing system conditions. The resulting order of magnitude unit pricing levels are included in the Generic Solution Cost Matrix in Appendix C.

5. 2011 CARIS Phase 1 Results

This section presents summary level results of six steps of the 2011 CARIS Phase 1. These six steps include: (1) congestion assessment; (2) ranking of congested elements; (3) selection of three studies; (4) generic solution applications; (5) benefit/cost analysis; and (6) scenario analysis. Study results are described in more detail in Appendix E.

5.1. Congestion Assessment

The CARIS process begins with the development of a ten-year projection of future congestion costs. This projection is combined with the past five years of historic congestion to identify and rank significant and recurring congestion. The results of the historical and future perspective are presented in the following two sections.

In order to assess and identify the most congested elements, both positive and negative congestion on constrained elements are taken into consideration. Whether congestion is positive or negative depends on the choice of the reference point. All metrics are referenced to the Marcy 345 kV bus near Utica, NY. For example, in the absence of losses, any location with LBMP greater than the Marcy LBMP has positive congestion, and any location with LBMP lower than the Marcy LBMP has negative congestion. The negative congestion typically happens due to transmission constraints preventing lower cost resources from being delivered towards the Marcy bus.

5.1.1. Historic Congestion

Historic congestion assessment has been conducted at the NYISO for the last seven years with metrics and procedures developed with the ESPWG and approved by the NYISO Operating Committee. Four congestion metrics were developed to assess historic congestion: Bid-Production Cost (BPC) as the primary metric, Load Payments metric, Generator Payments metric, and Congestion Payment metric. The results of the historic congestion analysis are posted on the NYISO website quarterly. For more information or source of historical results below see:

http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

Historic congestion costs by zone, expressed as Demand$, are presented in Table 5-1, indicating that the highest congestion is in New York City and Long Island.

Table 5-1: Historic Demand$ Congestion by Zone 2006-2010 (nominal $M)

Zone	2006	2007	2008	2009	2010
West	1	(14)	(25)	(14)	(1)
Genesee	2	(14)	(9)	4	6
Central	4	9	18	8	11
North	(0)	(0)	(2)	(3)	(1)
Mohawk Valley	2	5	10	4	5
Capital	27	74	143	53	62
Hudson Valley	54	87	176	57	73
Millwood	27	31	78	16	23
Dunwoodie	44	56	124	41	49
NY City	673	700	1403	503	560
Long Island	708	518	624	274	350
NYCA Total	**1,542**	**1,508**	**2,613**	**977**	**1,141**

Reported values do not deduct TCCs
NYCA totals represent the sum of absolute values
DAM data include Virtual Bidding & Transmission planned outages

Table 5-2 below lists historic congestion costs, expressed as Demand$, for top NYCA constraints* from 2006 to 2010. The top congested paths are shown below.

Table 5-2: Historic Demand$ Congestion by Constrained Paths 2006-2010 (nominal $M)

Constrained Path *	2006	2007	2008	2009	2010	Total
CENTRAL EAST	195	572	1,199	435	491	**2,892**
LEEDS_PLSNTVLY 345	452	435	667	149	232	**1,935**
DUNWOODIE_SHORRD_345	492	260	187	118	155	**1,212**
GREENWOOD LINES	119	90	113	87	132	**541**
WEST CENTRAL-OP	2	51	55	1	0	**109**
ASTORIAW138_HG5_138	1	2	1	0	0	**5**
GOTHLS S_ GOWANUS_ 345	0	0	0	0	0	**1**

* Ranking is based on absolute values.

Table 5-3 summarizes the annual historic congestion results posted by the NYISO. NYISO reports the summaries of the calculated changes in the four historic congestion metrics: BPC, Generator Payments, Congestion Payments, and Load Payments. The change in these four historic congestion metrics were calculated using PROBE as the constrained system values minus the unconstrained system values. Positive numbers imply savings while negative numbers imply increases in payments when all constraints are relieved. Unhedged Congestion is calculated as the total congestion represented by Demand$ Congestion minus the TCC hedge payments. Total payments made by load adjusted for the TCC hedges, TCC shortfalls, and Rate Schedule 1 imbalances comprise the statewide Unhedged Load Payments. These adjusted statewide Unhedged Load Payments equal the total Generator Payments.

Table 5-3: Historic NYCA System Changes – Mitigated Bids 2006-2010 (nominal $M)

Year	Change in BPC	Change in Generator Payments	Change in Unhedged Congestion Payments	Change in TCC Payments
2006	118	59	921	634
2007	130	(107)	806	670
2008	243	(417)	1,525	1,143
2009	82	(102)	477	480
2010	94	(116)	640	515

Figure 5-1 below illustrates a cumulative effect of bid production costs savings over the past five years as a result of relieving all NYCA constraints.

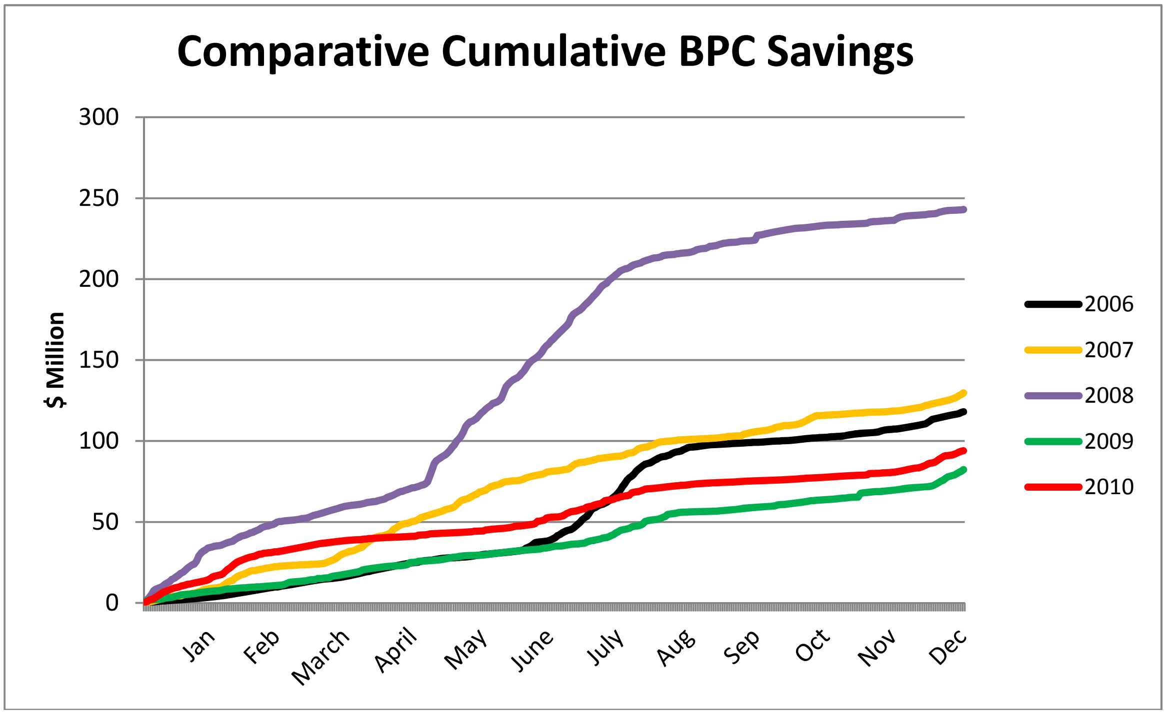


Figure 5-1: Historic Cumulative BPC Savings, 2006-2010 (nominal $M)

5.1.2. Projected Future Congestion

Future congestion for the 10 year study period was determined from a MAPS simulation using a ten year base case developed with the ESPWG. As reported in Section 3.2, congestion is reported as Demand$ congestion. MAPS simulations are highly dependent upon many long-term assumptions. The MAPS model utilizes input assumptions listed in Appendix C.

When comparing historic congestion costs to projected congestion costs, it is important to note that there are significant differences in assumptions used by the PROBE and MAPS. MAPS, unlike PROBE, did not simulate the following: (a) virtual bidding; (b) transmission outages; (c) fixed load and price-capped load; (d) generation and demand bid price; (e) Bid Production Cost Guarantee payments (BPCG); and (f) co-optimization with ancillary services.

Discussion

Table 5-4 presents the projected congestion from 2011 through 2020 by zone. The relative costs of congestion shown in this table indicate that the majority of the projected congestion is in the Downstate zones – NY City and Long Island. Year to year changes in congestion reflect changes in the model, which are discussed in Section 4.1.

Table 5-4: Projection of Future Demand$ Congestion 2011-2020 by Zone (nominal $M)

Zone	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
West	1	0	1	1	1	2	2	3	3	5
Genesee	1	0	0	0	0	0	1	1	2	2
Central	5	4	4	4	4	5	5	6	6	6
North	5	7	7	7	8	8	8	9	10	10
Mohawk Valley	3	2	2	2	2	3	3	3	3	4
Capital	46	40	41	37	38	43	46	52	56	57
Hudson Valley	56	50	51	47	50	55	59	69	76	80
Millwood	19	17	18	16	17	19	21	24	27	28
Dunwoodie	37	33	34	31	33	37	39	46	51	55
NY City	343	307	319	301	317	347	373	442	492	530
Long Island	192	185	193	190	202	222	240	273	297	320
NYCA Total	**709**	**646**	**670**	**636**	**672**	**740**	**796**	**929**	**1023**	**1098**

Note: Reported costs have not been reduced to reflect TCC hedges and represent absolute values

Based on the positive Demand$ congestion costs, the future top congested paths are shown in Table 5-5 below.

Table 5-5: Projection of Future Demand$ Congestion 2011-2020 by Constrained Path (nominal $M)

Nominal Value ($M) *	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
CENTRAL EAST	268	226	229	209	212	243	257	295	318	329	**2,584**
LEEDS_PLSNTVLY 345	228	199	206	187	205	231	250	307	346	377	**2,535**
DUNWOODIE_SHORRD_345	41	46	49	54	57	60	65	69	73	80	**595**
GREENWOOD LINES	10	10	11	12	12	12	13	15	17	19	**131**
GOTHLS S_ GOWANUSS_ 345	5	4	4	4	5	5	5	6	7	8	**52**

* The absolute value of congestion is reported.

5.2. Ranking of Congested Elements

The identified congested elements from the ten-year projection of congestion are lined up with the past five years of identified historic congested elements to develop fifteen years of Demand$ congestion statistics for each initially identified top constraint. The fifteen years of statistics are analyzed to determine recurring congestion or the mitigation of congestion from future system changes incorporated into the base CARIS system that may lead to exclusions. Ranking of the identified constraints is initially based on the highest present value of congestion over the fifteen-year period with five years historic and ten years projected.

Table 5-6 lists the ranked elements based on the highest present value of congestion over the fifteen years of the study, including both positive and negative congestion. Central East and Leeds - Pleasant Valley continue to be the paths with the greatest congestion. The level of congestion over the Dunwoodie-Shore Road path diminishes in the future with the recent addition of the Caithness plant. The top seven elements are evaluated in the next step for selection of the three studies.

Table 5-6: Ranked Elements Based on the Highest Present Value of Demand$ Congestion over the Fifteen Years Aggregate

	Present Value of Congestion (in 2011 $M)		
Constraints *	**Historic**	**Future**	**Aggregate**
CENTRAL EAST	$3,426	$1,810	$5,237
LEEDS-PLEASANT VALLEY	$2,383	$1,741	$4,124
DUNWOODIE-SHOR RD	$1,526	$409	$1,935
GREENWOOD LINES	$648	$90	$737
WEST CENTRAL-OP	$135	$28	$163
GOTHLS-GOWANUSS	$1	$36	$37
ASTORIAW138-HG5	$6	$4	$10

*The absolute value of congestion is reported.

The frequency of actual and projected congestion is shown in Table 5-7 below. The table presents the actual number of congested hours by constraint, from 2007 through 2010, and projected hours of congestion, from 2011 through 2020. The number of projected hours of congestion, by constraint after each generic solution is applied, is reflected in Appendix E.

Table 5-7: Number of Congested Hours by Constraint

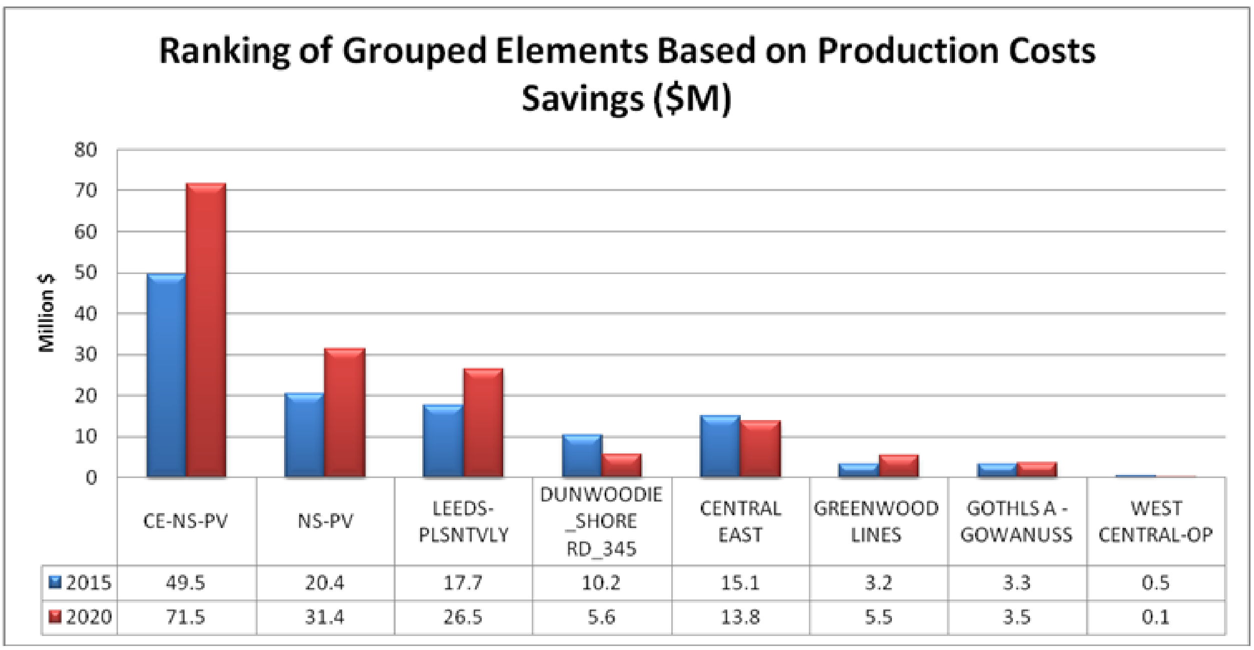
# of DAM Congested Hours	**Actual**				**CARIS Base Case Projected**									
Constraint	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
DUNWOODIE-SHORE RD	5,603	4,469	5,240	4,292	7,820	8,247	8,390	8,423	8,421	8,402	8,403	8,402	8,385	8,374
GOTHLS - GOWANUS 345	931	329	121	460	2,801	3,084	3,126	2,991	3,015	3,074	3,037	3,235	3,264	3,153
GREENWOOD LINES	4,593	4,741	4,330	4,317	4,382	4,394	4,277	4,164	4,116	3,613	3,561	3,769	3,778	3,974
CENTRAL EAST	3,195	5,182	4,788	2,964	1,889	1,836	1,945	1,793	1,754	1,685	1,748	1,893	1,878	1,908
LEEDS PLSNTVLY	1,572	1,083	725	673	1,830	1,710	1,770	1,811	1,843	1,866	1,881	2,048	2,131	2,261
ASTORIAW138_HG5_138	-	-	-	-	1,361	1,894	1,961	1,951	2,004	2,478	2,502	2,489	2,519	2,238
WEST CENTRAL	1,943	2,120	296	1	118	436	588	439	471	642	710	831	893	918

5.3. Three CARIS Studies

5.3.1. Selection of the Three Studies

Selection of the three CARIS studies is a two-step process in which the top seven ranked constraints are identified and utilized for further assessment in order to identify potential for grouping of constraints. Resultant grouping of elements for each of the top seven ranked constraints is utilized to determine the three studies. This process is explained in Section 5.2.

Before applying the first step, Astoria West was eliminated from consideration because the congestion was de minimus. In the first step, the remaining six congested elements with the highest present value ranking were utilized for further assessment. In the second step, the assessment was accomplished in multiple iterations to include additional elements that appear as limiting when each of the top six congested elements are relaxed by removing their limits. The assessed element groupings are then ranked based upon the highest change in production cost as shown in Figure 5-2.



	CE-NS-PV	NS-PV	LEEDS-PLSNTVLY	DUNWOODIE _SHORE RD_345	CENTRAL EAST	GREENWOOD LINES	GOTHLS A - GOWANUSS	WEST CENTRAL-OP
2015	49.5	20.4	17.7	10.2	15.1	3.2	3.3	0.5
2020	71.5	31.4	26.5	5.6	13.8	5.5	3.5	0.1

Figure 5-2: Production Costs Savings, 2015 and 2020 (nominal $M)

The three ranked groupings with the largest change in production cost are selected as the three CARIS studies: Central East-New Scotland-Pleasant Valley (CE-NS-PV), New Scotland – Pleasant Valley (NS-PV) and Leeds-Pleasant Valley (L-PV). Table 5-8 has the base case congestion associated with each of the three studies. A detailed discussion on the ranking process is presented in Appendix E.

Table 5-8: Demand$ Congestion of the Top Three CARIS Studies (nominal $M)

Study	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Central East-New Scotland-Pleasant Valley (Study 1)	495	425	436	398	419	474	507	603	667	708
New Scotland-Pleasant Valley (Study 2)	228	200	207	189	207	231	250	308	349	379
Leeds-Pleasant Valley (Study 3)	228	199	206	187	205	231	250	307	346	377

The location of the top three congested groupings, which define the three studies, along with their present value of congestion (in 2011 dollars) is presented in Figure 5-3.

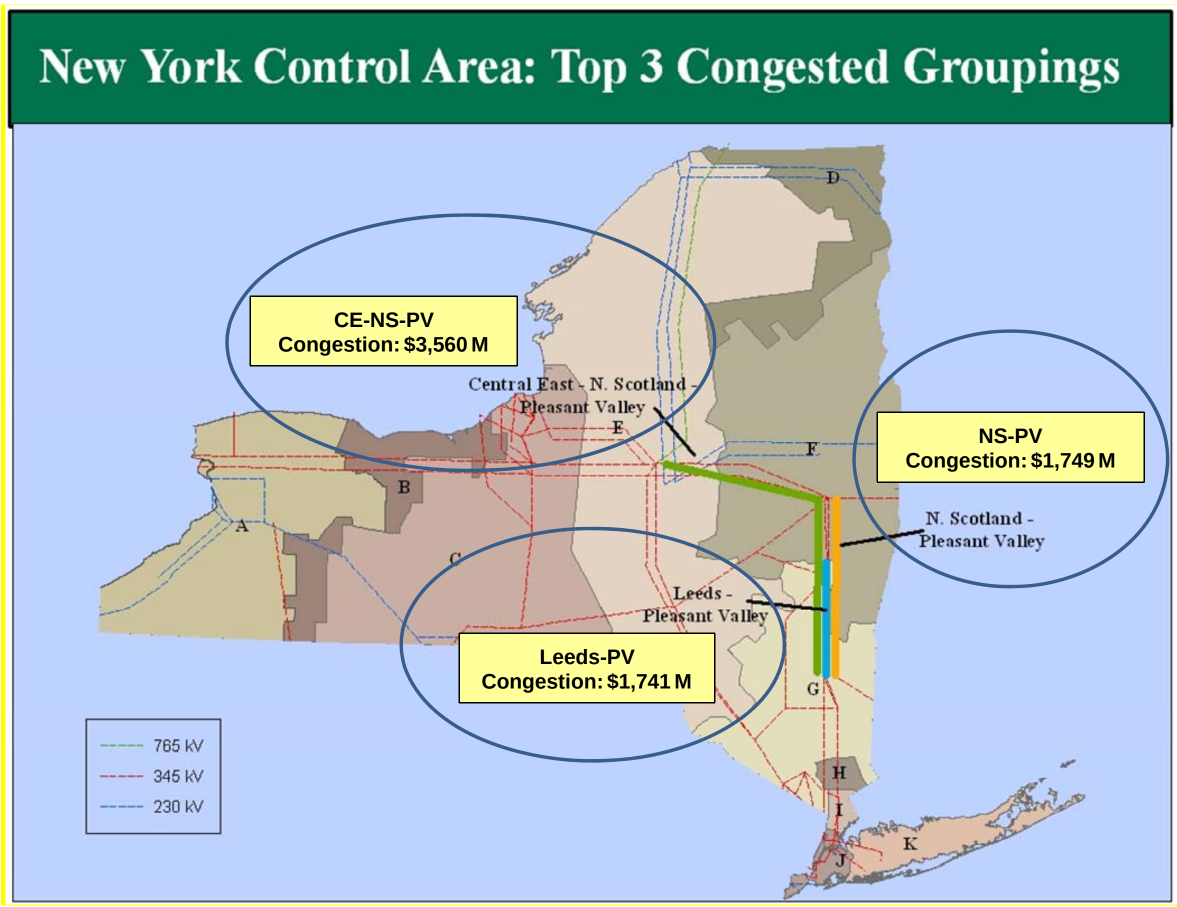


Figure 5-3: Base Case Congestion of Top 3 Congested Groupings, 2011-2020 - Present Value ($M)

5.3.2. Generic Solutions to Congestion

The congestion of each of the three groupings being studied is mitigated by individually applying one of the generic resource types; transmission, generation and demand response. The resource type is applied based on the rating and size of the blocks determined in the Generic Solutions Cost Matrix included in Appendix C and is consistent with the methodology explained in Section 4 of this report. Resource blocks were applied to relieve a majority of the congestion. Additional resource blocks were not added if diminishing returns would occur.

In regard to the generic solutions, it is important to note the following:

- Other solutions may exist which will alleviate the congestion on the studied elements.
- No attempt has been made to determine the optimum solution for alleviating the congestion.
- No engineering, physical feasibility study, routing study or siting study has been completed for the generic solutions. Therefore, it is unknown if the generic solutions can be physically constructed as proposed.
- Generic solutions are not assessed for impacts on system reliability.
- Actual projects will incur different costs.
- The generic solutions differ in the degree to which they relieve the identified congestion.
- For each of the base case and solution cases, HQ imports are held constant.

The discount rate used for the present values analysis is the weighted average of the after-tax Weighted Average Cost of Capital (WACC) for the NYTOs. The weighted average is based on the utilities' annual GWh sendout of energy for 2010.

The results of the three generic solutions are provided below with more detail in Appendix E. The following generic solutions were applied for each study:

Study 1: Central East – New Scotland – Pleasant Valley

The following generic solutions were applied for Central East – New Scotland -Pleasant Valley Study:

- Transmission: A new 345 kV line from Edic to New Scotland to Pleasant Valley, 155 Miles. The new line increases the Central East voltage transfer limit by approximately 600 MW and the UPNY-SENY thermal capability by up to 1200 MW.
- Generation: A new 1,000 MW Plant at Pleasant Valley
- Demand Response & Energy Efficiency (DR/EE): 100 MW Demand Response and 100 MW Energy Efficiency for a total of 200MW in Zone F and 200MW in Zone G (200 MW is less than 10% of peak load in each of Zones F & G)

Table 5-9 shows the Demand$ congestion of Central East – New Scotland – Pleasant Valley for 2015 and 2020 before and after each of the generic solutions is applied. The base Case congestion numbers, $419M for 2015 and $708M for 2020, are taken directly from Table 5-8 representing the level of congestion of the Study 1 before the solutions.

Table 5-9: Demand$ Congestion Comparison for Central East – New Scotland – Pleasant Valley Study (nominal $M)

	2015			2020		
Resource Type	**Solution**	**Base Case**	**% Change**	**Solution**	**Base Case**	**% Change**
Transmission	190	419	-55%	305	708	-57%
Generation – 1000 MW	96	419	-77%	195	708	-72%
Demand Response	405	419	-3%	696	708	-2%

Table 5-10 shows the production cost savings expressed as the present value in 2011 $ from 2011 to 2020 for the Central East – New Scotland – Pleasant Valley study after generic solutions were applied.

Table 5-10: Central East – New Scotland – Pleasant Valley Study: NYCA-wide Production Cost Savings(Present Value in 2011 $M)

Resource Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Transmission	46	39	36	33	33	32	32	31	34	34
Generation - 1000 MW	26	32	29	30	31	37	36	35	36	37
Demand Response	49	48	45	45	44	43	42	39	39	38

The Central East – New Scotland – Pleasant Valley 345 kV transmission solution relieves the congestion across existing Central East – New Scotland – Leeds-Pleasant Valley transmission lines by 55% in 2015 and 57% in 2020 respectively, as shown in Table 5-9. In Table 5-10, the annual production cost savings are relatively flat in present value, but increase in nominal value from 2014 to 2020 as fuel prices increase. Total ten year NYCA-wide production cost savings is $350 million (present value) as the result of better utilization of economic generation in the state and economic imports from neighboring regions made available by the large scale transmission upgrades represented by this generic transmission solution.

The generation solution reduces congestion by 77 % in 2015 and 72% in 2020. The ten-year production cost savings of $330 million (present value) are due to the uncongested location and the assumed better heat rate of the generic generating unit compared to the average system heat rate.

The Zones F and G DR/EE solution reduces congestion by 3% in 2015 and 2% in 2020, while the ten-year total production cost saving is $432 million (present value). The relative large value of production cost saving is largely attributable to the reduction in energy use of the DR/EE solution itself.

Study 2: New Scotland – Pleasant Valley

The following generic solutions were applied for New Scotland – Pleasant Valley study:

- Transmission: A new 345 kV line from New Scotland to Pleasant Valley, 65 Miles. The new line increases the UPNY-SENY transfer capability by up to 1200 MW and the Central East voltage limit by 100 MW.
- Generation: A new 1,000 MW Plant at Pleasant Valley
- Demand Response & Energy Efficiency (DR/EE): 100 MW Demand Response and 100 MW Energy Efficiency for a total of 200MW in Zone G and 200MW in Zone I (200 MW is less than 10% of peak load in each of Zones G & I)

Table 5-11 shows the Demand$ congestion of New Scotland – Pleasant Valley for 2015 and 2020 before and after each of the generic solutions is applied.

Table 5-11: Demand$ Congestion Comparison for New Scotland – Pleasant Valley Study (nominal $M)

	2015			2020		
Resource Type	**Solution**	**Base Case**	**% Change**	**Solution**	**Base Case**	**% Change**
Transmission	14	207	-93%	44	379	-88%
Generation - 1000 MW	96	207	-54%	195	379	-49%
Demand Response	187	207	-10%	345	379	-9%

Table 5-12 shows the NYCA-wide production cost savings expressed as the present value in 2011 $ from 2011 to 2020 for the New Scotland – Pleasant Valley study after generic solutions were applied.

Table 5-12: New Scotland – Pleasant Valley Study: NYCA-wide Production Cost Savings

(Present Value in 2011 $M)

Resource Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Transmission	27	23	21	20	20	19	19	18	20	21
Generation - 1000 MW	26	32	29	30	31	37	36	35	36	37
Demand Response	47	48	44	44	43	42	41	38	38	37

The addition of the New Scotland – Pleasant Valley line relieves the New Scotland – Pleasant Valley congestion by 93% in 2015 and 88% in 2020. The total ten-year production cost savings of $208 million (present value) are again due to increased use of lower cost generation in upstate and increased levels of imports compared to the base case. The Central East congestion increased in this solution.

The generation solution reduces congestion by 54 % in 2015 and 49% in 2020. The ten-year production cost savings of $330 million (present value) are derived from the heat rate efficiency advantage of the new generic unit compared to the average system heat rate. Imports are significantly reduced in this solution.

The Zones G and I DR/EE solution reduces congestion by 9 – 10% . The ten-year production cost savings of $421 million (present value) are largely related to the reduction in energy use.

Study 3: Leeds – Pleasant Valley

The following generic solutions were applied for the Leeds-Pleasant Valley study, and the results are shown in Table 5-11:

- Transmission: A new 345 kV line from Leeds to Pleasant Valley; 39 Miles. The new line increases the UPNY-SENY thermal capability by up to 1000 MW and Central East voltage limit by 50 MW.
- Generation: Install a new 1000 MW Plant at Pleasant Valley.
- Demand Response & Energy Efficiency (DR/EE): 100 MW demand response and 100 MW Energy Efficiency for a total of 200 MW in Zone G and 200MW in Zone I (200 MW is less than 10% of peak load in each of Zones G & I).

Table 5-13 shows the Demand$ congestion of Leeds-Pleasant Valley for 2015 and 2020 before and after each of the generic solutions is applied. Transmission has the greatest impact in reducing congestion and eliminated the entire congestion for the Leeds-Pleasant Valley path.

Table 5-13: Demand$ Congestion Comparison for Leeds-Pleasant Valley (nominal $M)

	2015			2020		
Resource Type	**Solution**	**Base Case**	**% Change**	**Solution**	**Base Case**	**% Change**
Transmission	0	205	-100%	0	377	-100%
Generation - 1000 W	96	205	-53%	195	377	-48%
Demand Response	187	205	-9%	345	377	-8%

Table 5-14 shows the NYCA-wide production cost savings expressed as the present value in 2011 $ from 2011 to 2020 for the Leeds-Pleasant Valley study after the generic solutions were applied.

Table 5-14: Leeds-Pleasant Valley Study: NYCA-wide Production Cost Savings

(Present Value in 2011$M)

Resource Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Transmission	21	16	15	15	15	14	15	13	15	15
Generation - 1000 MW	26	32	29	30	31	37	36	35	36	37
Demand Response	47	48	44	44	43	42	41	38	38	37

The addition of the Leeds to Pleasant Valley 345 kV transmission line results in a total ten-year production cost savings of $154 million (present value). Elimination of the Leeds-Pleasant Valley congestion allows the downstate load better access to upstate generation and economic imports from neighbors. It is also noted that relieving the congestion on the Leeds-Pleasant Valley lines increases the congestion on the other two study groups.

The generation solution reduces congestion across NYCA for the planning horizon. The ten-year production cost savings of $330 million (present value) are due to the uncongested location and the assumed better heat rate of the generic generating unit compared to the average system heat rate.

The Zones G and I DR/EE solution reduces congestion by 8 – 9%. The ten-year production cost savings of $421 million (present value) are largely related to the reduction in energy use.

The NYCA-wide production cost savings of the three generic solutions for the three studies are summarized and shown in Figure 5-4.

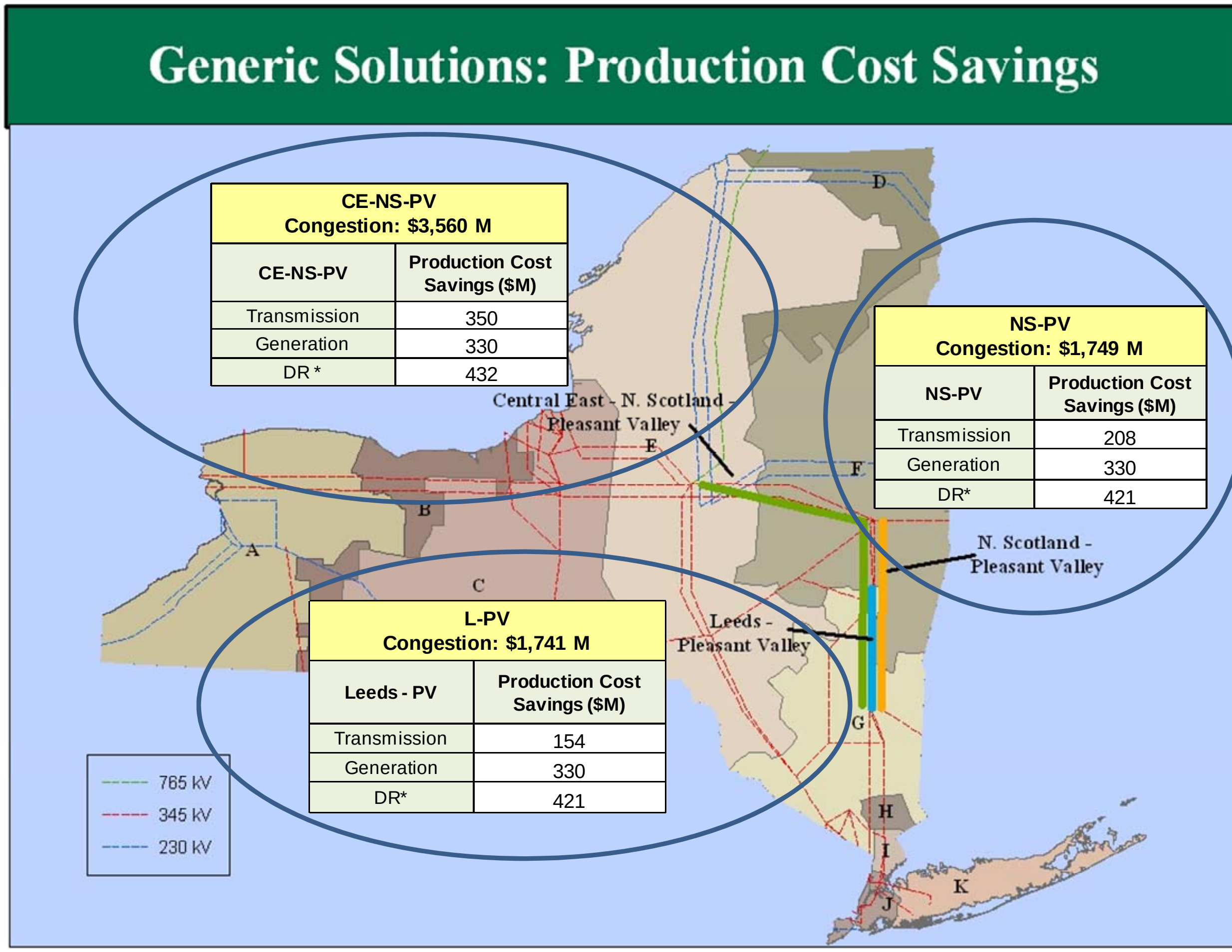


Figure 5-4: Total NYCA-wide Production Cost Savings 2011-2020 (Present Value in 2011 $M)

5.4. Benefit/Cost Analysis

The NYISO conducted the benefit/cost analysis for each of the three: Central East – New Scotland – Pleasant Valley, New Scotland – Pleasant Valley, and Leeds – Pleasant Valley. The CARIS benefit/cost analysis assumes a levelized generic carrying charge rate of 16% for transmission and generation solutions. Therefore, for a given generic solution pertaining to a constrained element, the carrying charge rate, in conjunction with an appropriate discount rate (see description in Section 5.4 above) yields a capital recovery factor, which, in turn, is used to calculate the benefit/cost ratio.

$$\text{Benefit/Cost ratio} = \frac{\text{Present Value of Production Cost Savings}}{\text{Overnight Costs x Capital Recovery Factor}}$$

The 16% carrying charge rate used in these CARIS benefit/cost calculations reflects generic figures for a return on investment, federal and state income taxes, property taxes, insurance, fixed O&M, and depreciation (assuming a straight-line 30-year method). The calculation of the appropriate capital recovery factor, and, hence, the B/C ratio, is based on the first ten years of the 30-year period,[10] using a discount rate of 7.4% yielding a Capital Recovery Factor equal to 1.145.

5.4.1. Cost Analysis

Table 5-15 includes the total cost estimate for each generic solution based on the unit pricing included in Appendix C. The detailed cost breakdown for each solution is included in Appendix E. These are simplified estimates of overnight installation costs and do not include any of the complicating factors that could be faced by individual projects. On-going fixed operation and maintenance costs and other fixed costs of operating the facility are captured in the capital recovery factor.

[10] The carrying charge rate of 16% was based on a 30-year period because the Tariff provisions governing Phase 2 of CARIS refer to calculating costs over 30 years for information purposes. See OATT Attachment Y, Section 31.4.3.3.4.

Table 5-15: Generic Solution Costs for Each Study

Generic Solution Cost Summary ($M)			
	Study 1:	**Study 2:**	**Study 3:**
Studies	**Central East-New Scotland-Pleasant Valley**	**New Scotland-Pleasant Valley**	**Leeds - Pleasant Valley**
Transmission			
Substation Terminals	Edic to New Scotland to Pleasant Valley	New Scotland to Pleasant Valley	Leeds to Pleasant Valley
Miles (# of terminals)	155 (3)	65 (2)	39 (2)
High	$1,168	$502	$312
Mid	$799	$343	$213
Low	$322	$139	$87
Generation			
Substation Terminal	Pleasant Valley	Pleasant Valley	Pleasant Valley
# of 500 MW Blocks	2	2	2
High	$1,988	$1,988	$1,988
Mid	$1,622	$1,622	$1,622
Low	$1,256	$1,256	$1,256
Demand Response			
Zone	F & G	G&I	G&I
# of 200 MW Blocks	2	2	2
High	$672	$754	$754
Mid	$540	$605	$605
Low	$406	$454	$454

5.4.2. Primary Metric Results

The primary benefit metric for the three CARIS studies is the reduction in NYCA-wide production costs. Table 5-16 shows the production cost savings used to calculate the benefit/cost ratios for the generic solutions. Transmission has the greatest impact on reducing Demand$ congestion (55% to 100%) because adding a transmission solution addresses the underlying system constraint that was driving the congestion. The generation solution reduced Demand$ congestion by 48% to 77%. A large portion of the production cost savings resulting from generation can be attributed to the efficiency advantage of the generic generation solution when compared to the system wide heat rate. The demand response solution reduced Demand$ congestion by 2% to 10%, yet shows significant production cost savings because it directly reduces the energy production requirements.

Table 5-16: Production Cost Generic Solutions Savings 2011-2020: Present Value in 2011 ($M)

	Central East to New Scotland to Pleasant Valley	New Scotland to Pleasant Valley	Leeds to Pleasant Valley
Transmission	350	208	154
Generation	330	330	330
DR/EE	432	421	421

5.4.3. Benefit/Cost Ratios

Figure 5-5 shows the benefit/cost ratios for each study and each generic solution relative to high, medium and low cost estimates.

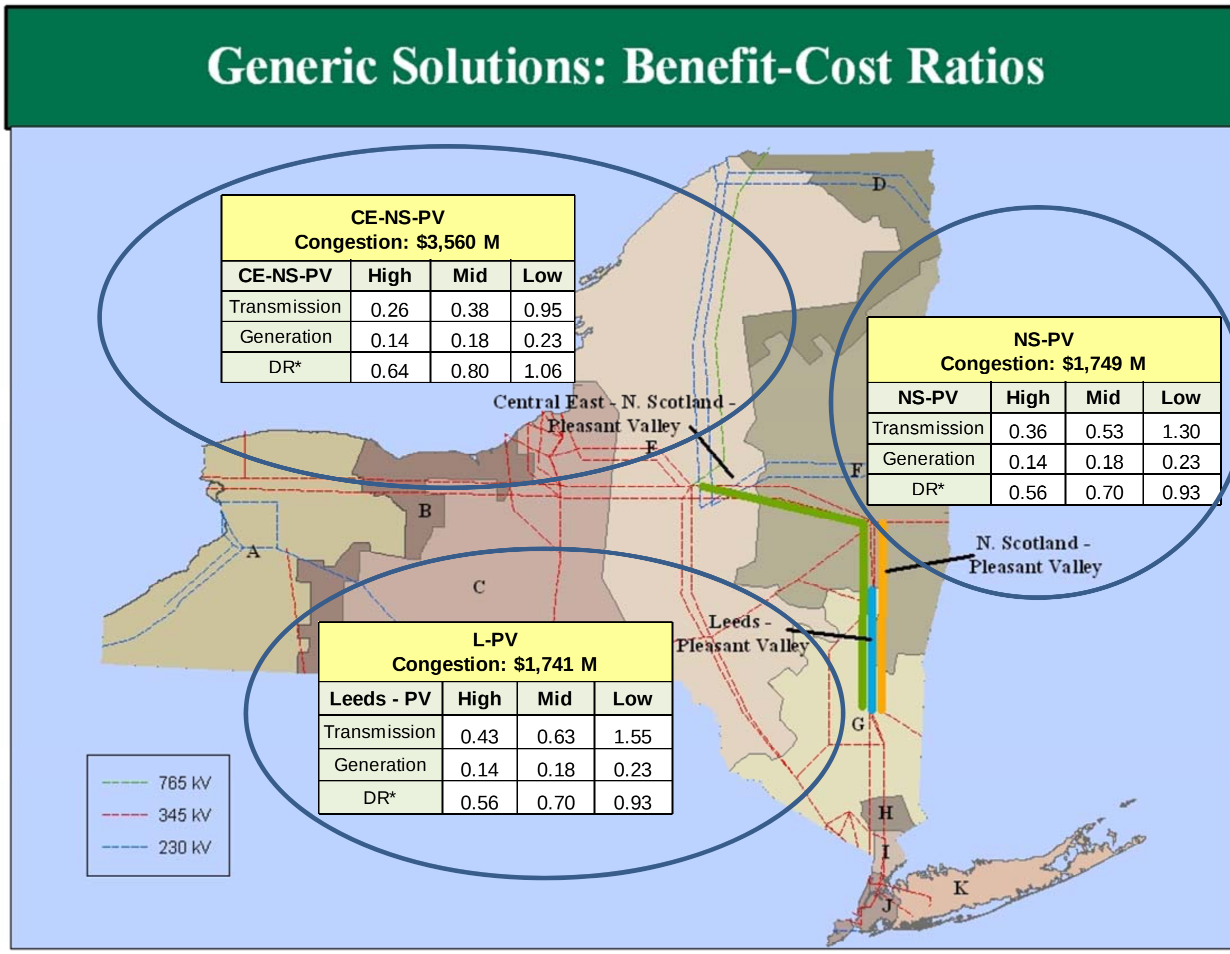


Figure 5-5: B/C Ratio (High, Medium, and Low Cost Estimate Ranges)

5.4.4. Additional Metrics Results

Additional metrics, which are provided for information purposes in Phase 1, are presented in Table 5-17, Table 5-18, and Table 5-19 to show the nominal ten-year total change in: (a) generator payments; (b) LBMP load payments; (c) TCC payments (congestion rents); (d) losses; (e) emission costs/tons; and (f) ICAP MW and cost impact, after the generic solutions are applied. The values represent the generic solution values less the base case values for all the metrics except for the ICAP metric. Details on the calculations are in Appendix E.

While all but the ICAP metric are direct outputs of the production cost simulation program, the ICAP metrics are computed using the latest available information from the installed reserve margin (IRM), locational capacity requirement (LCR), and ICAP Demand Curves. Actual calculation consists of two steps. In the first step, the MW impact of a generic solution is determined through Loss of Load Expectation (LOLE) analysis, where LOLE is the resource adequacy criterion. The MW impact is indicative of reduced installed capacity requirement made possible by the congestion mitigation solutions. A transmission solution that enables better utilization of the existing generating resources in the State will allow a lower IRM and lower LCR. Generation solutions, depending on their location in the NYCA, will contribute as an ICAP source and may reduce the IRM and LCR requirements. For DR/EE, the reduced load downstream of congestion will lower both the overall ICAP and the LCR requirements. The ICAP reduction can be larger than the nameplate of the solution in megawatts. Using year 2020 as an example, the ICAP MW impact for each study area resulting from the application of generic solutions is reported in Table 5-18.

Second, the ICAP cost reduction benefit is translated to a dollar amount through two pricing variations for each of the years of the ten year study period. For the first variant, the MW impact is priced at the calculated point on the forecast demand curves for each of the three capacity regions in NYCA. For the second variant, the MW impact is priced based on the forecast change in clearing price for each of the three capacity regions in NYCA. Both of the two ICAP cost savings are shown in Table 5-17. For details on all 10 years, see Appendix E.

Table 5-17: Change in NYCA Generator and Load Payments, Congestion Rents, Losses, and ICAP Cost

		Generator Payments	Load Payments	Congestion Rents*	Losses Costs	ICAP Costs Variant 1	ICAP Costs Variant 2
Study	**Solution**	Change: Nominal $M				Savings: Nominal $M	
	Transmission						
Study 1: CE-NS-PV	Edic-New Scotland-Pleasant Valley	534	136	(1234)	(511)	383	3319
Study 2: NS-PV	New Scotland-Pleasant Valley	273	4	(1003)	(215)	359	3125
Study 3: Leeds-PV	Leeds – Pleasant Valley	394	147	(789)	(126)	335	2931
	Generation						
Study 1: CE-NS-PV	Pleasant Valley	768	(1306)	(347)	39	77	1460
Study 2: NS-PV	Pleasant Valley	768	(1306)	(347)	39	77	1460
Study 3: Leeds-PV	Pleasant Valley	768	(1306)	(347)	39	77	1460
	DR & EE						
Study 1: CE-NS-PV	Zone F&G	(573)	(894)	23	(30)	150	1303
Study 2: NS-PV	Zone G & I	(513)	(883)	(64)	(58)	235	1929
Study 3: Leeds-PV	Zone G & I	(513)	(883)	(64)	(58)	235	1929

*Congestion Rents are calculated as Shadow Price times Flow across all constraints in the system.

Table 5-18: ICAP MW Impact

Study	Solutions	2020 MW Impact (MW)			
		ROS	NYC	LI	Total
Study 1: Central East-New Scotland-Pleasant Valley	Transmission	507	184	109	700
	Generation	824	299	177	1300
	Demand Response	222	80	48	350
Study 2: New Scotland-Pleasant Valley	Transmission	475	172	102	700
	Generation	824	299	177	1300
	Demand Response	348	126	75	550
Study 3:Leeds-Pleasant Valley	Transmission	444	161	96	700
	Generation	824	299	177	1300
	Demand Response	348	126	75	550

The ten-year changes in total emissions resulting from the application of generic solutions are reported in Table 5-19 below. The base case ten-year emission totals for NYCA are: CO_2 = 401,534 tons, SO_2= 289,765 tons and NOx = 237,134 tons. The study results reveal that most of the generic solutions impact emissions by less than 2%, with the exception of generation solutions impacting SO_2 and NOx emissions up to 7% and 4% respectively. The current installed capacity in NYCA as reported in the 2011 Gold Book is 37,707 MW. The generic generation solution of 1,000 MW represents the equivalent of 2.7 % increase in installed capacity. The generic demand response solution of 200 MW of DR and 200 MW of EE could be considered as an additional resource which would be equivalent to 1.1% of installed capacity. The capability of the generic transmission solution is 1,000 MVA, which would be utilized to shift dispatch patterns of several hundred MW of capacity, or something on the order of 1% of installed capacity. The three generic solutions can be considered to change the fleet characteristics on the order of 1%, which is consistent with the changes in emission patterns.

The comparison of the relative emission changes among solution types and across locations provides insight about the relative air related impacts. Both transmission and demand response solutions show improvements by reducing the emissions of all three pollutants up to 1.3%. Generation solutions produce a net reduction in the emissions of SO_2 and NOx, due to the relative low emission rates of a new unit compared to the average emission rates of the existing fleet. The Pleasant Valley location offers the greatest emission reductions in SO_2 (7%) and NOx (4%). Generic generation solutions lead to a slight increase in CO_2 emissions when a 1,000 MW generation solution is applied.

Table 5-19: Ten-Year Change in NYCA CO2, SO2 and NOx Emissions

		SO2			CO2			NOx		
Study	**Solution**	**Tons**	**% Change**	**Cost ($m)**	**'000s Tons**	**% Change**	**Cost ($m)**	**Tons**	**% Chang**	**Cost ($m)**
	Transmission									
Study 1: CE-NS-PV	Edic-New Scotland-Pleasant Valley	218	0.08%	0	(3705)	-0.92%	(56)	(2327)	-0.98%	(3)
Study 2: NS-PV	New Scotland-Pleasant Valley	(1637)	-0.56%	(1)	(4083)	-1.02%	(69)	(3029)	-1.28%	(4)
Study 3: Leeds-PV	Leeds – Pleasant Valley	(1644)	-0.57%	(1)	(2979)	-0.74%	(51)	(2114)	-0.89%	(3)
	Generation									
Study 1: CE-NS-PV	Pleasant Valley	(18961)	-6.54%	(6)	5404	1.35%	94	(8742)	-3.69%	(12)
Study 2: NS-PV	Pleasant Valley	(18961)	-6.54%	(6)	5404	1.35%	94	(8742)	-3.69%	(12)
Study 3: Leeds-PV	Pleasant Valley	(18961)	-6.54%	(6)	5404	1.35%	94	(8742)	-3.69%	(12)
	Demand Response									
Study 1: CE-NS-PV	Zone F & G	(2710)	-0.94%	(1)	(3028)	-0.75%	(50)	(1591)	-0.67%	(2)
Study 2: NS-PV	Zone G & I	(2719)	-0.94%	(1)	(3128)	-0.78%	(51)	(1735)	-0.73%	(2)
Study 3: Leeds-PV	Zone G & I	(2719)	-0.94%	(1)	(3128)	-0.78%	(51)	(1735)	-0.73%	(2)

5.5. Scenario Analysis

Scenario analysis is performed to explore the impact on congestion associated with variables to the base case. Since this is an economic study and not a reliability analysis, these scenarios focus upon factors that impact the magnitude of congestion across constrained elements.

A forecast of congestion is impacted by many variables for which the future values are uncertain. Scenario analyses are methods of identifying the relative impact of pertinent variables on the cost of congestion. The CARIS scenario studies were presented to ESPWG and modified based upon the input received and the availability of NYISO resources. The focus of these studies was to examine the impact of the full amount of the resources added through the State Renewable Portfolio Standard (RPS) combined with the full achievement of the State Energy Efficiency Portfolio Standard (EEPS), fuel price and load forecast uncertainties, costs of emissions, and maintaining the Athens SPS in service. The objective of the scenario analysis is to determine the change in the costs of congestion that is caused by variables that differ from the base case. The simulations were conducted for the mid-period year (2015) and the horizon year (2020).

5.5.1. Scenario Analysis

Table 5-20 summarizes the scenarios studied in CARIS Phase 1. The scenarios build upon the base case assumptions and variables to the base case assumptions identified in the table below.

Table 5-20: Scenario Matrix

Scenario	Variables
1. EPA Projected NOx and SO_2 Allowance Costs	
2. Higher Load Forecast	6% increase
3. Higher Natural Gas Prices	One standard deviation
4. Full RPS and Full EEPS Goals Achievement	Add renewables from Interconnection Queue to achieve 9870 GWh goal and reduce 2015 load to 32147 MW
5. Athens SPS Continued In Service	2011-2020
6. Lower Load Forecast	9% decrease
7. Lower CO_2 Emission Allowance Costs	$5/ton ceiling
8. Lower Natural Gas Prices	One standard deviation

Table 5-21 presents the impact of eight scenarios selected for study. Those impacts are expressed as changes in congestion costs between the scenarios and the base case. Negative numbers represent a reduction in congestion.

Table 5-21: Comparison of Base Case and Scenario Cases, 2015 and 2020 (nominal $M)

			2015 Scenarios: Base Case Demand$ Congestion ($M)							
Scenario #			1	2	3	4	5	6	7	8
CONSTRAINTS	TYPE	BASE CASE	EPA Projected NOx and SO_2 Costs	Higher Load Forecast	Higher Natural Gas Prices	Full RPS and Full EEPS goals Achievement	Athens SPS Continued in Service	Lower Load Forecast	Lower Carbon Emission Costs	Lower Natural Gas Prices
LEEDS-PLSNTVLY	Contingency	**205**	177	244	228	221	130	138	170	173
CENTRAL EAST	Interface	**212**	253	219	272	563	232	268	171	110
DUNWOODIE_SHORE RD_345	Contingency	**57**	75	61	64	61	61	56	58	46
GREENWOOD LINES	Contingency	**12**	11	15	13	11	12	8	12	12
WEST CENTRAL-OP	Interface	**2**	(3)	(2)	(4)	(1)	(3)	(2)	(0)	(2)
GOTHLS A - GOWANUSS	Contingency	**5**	6	6	5	4	4	3	4	4
LEEDS3_NEW SCOTLAND_345	Contingency	**0**	0	0	2	2	2	3	0	1
RAINY8W138_VERNW_138	Contingency	**2**	3	2	3	2	2	2	3	1
ASTORIAW138_HG5_138	Contingency	**(0)**	(0)	(0)	(0)	(1)	0	(0)	0	(0)

			2020 Scenarios: Base Case Demand$ Congestion ($M)							
Scenario #			1	2	3	4	5	6	7	8
CONSTRAINTS	TYPE	BASE CASE	EPA Projected NOx and SO2 Costs	Higher Load Forecast	Higher Natural Gas Prices	Full RPS and Full EEPS Goals Achievement	Athens SPS Continued in Service	Lower Load Forecast	Lower Carbon Emission Costs	Lower Natural Gas Prices
LEEDS-PLSNTVLY	Contingency	377	417	440	412	399	253	269	330	337
CENTRAL EAST	Interface	329	266	317	389	817	369	428	312	207
DUNWOODIE_SHORE RD_345	Contingency	80	107	85	87	84	85	76	83	66
GREENWOOD LINES	Contingency	19	20	24	20	17	19	13	20	18
WEST CENTRAL-OP	Interface	9	(12)	(8)	(11)	(6)	(10)	(9)	(2)	(7)
GOTHLS A - GOWANUSS	Contingency	8	9	11	8	7	7	5	8	7
LEEDS3_NEW SCOTLAND_345	Contingency	0	6	2	2	3	5	2	0	3
RAINY8W138_VERNW_138	Contingency	2	2	2	3	2	2	2	3	1
ASTORIAW138_HG5_138	Contingency	(1)	(2)	(1)	(1)	(1)	0	(1)	0	(1)

Scenario 1: EPA Projected NOx and SO_2 Costs

Emissions of SO_2 and NOx have costs that are determined by various cap and trade programs currently in effect in New York and in most of the surrounding regions. Forecasts used in the base case for these allowance costs were developed using various private and public data such as some proprietary forecasts, EPA's allowance price, and market prices from the Chicago Climate Futures Exchange. To examine factors that might produce or increase congestion, the forecast costs of NOx and SO_2 emissions were modeled based on EPA projections for 2015 and 2020, resulting from the Cross-State Air Pollution Rule.

Scenario 2: Higher Load Forecast

This scenario examined the impact of the higher load forecast on the cost of congestion. The high load forecast is obtained from the 2011 Gold Book, and is 6% higher than the 2011 Gold Book Baseline load forecast. The high load forecast is 35,738 MW and 36,988 MW respectively in 2015 and 2020. All other assumptions were the same as in the base case.

Scenario 3: Higher Natural Gas Prices

This scenario examines the cost of congestion when natural gas prices are projected to be higher than the base case levels by one standard deviation. The volatility of natural gas prices varies across the year such that it is most volatile in winter months and relatively stable during late spring. Consequently, as compared to the base case, the high price case can see January prices around 22% higher for Downstate and 12% higher for Upstate, while remaining about the same in May-June in both cases.

Scenario 4: Full RPS and EEPS Goals Achievement

This scenario adds renewable generation projects from the NYISO Interconnection queue to achieve the renewable goal of 9,870 GWh by 2015, and models load reductions which achieve the goal of 15% load reduction resulting in a peak load projection of 32,147 MW in 2015.

Scenario 5: Athens SPS Continued In Service

This scenario assumed that the Athens SPS is continued in service throughout the study period from 2011 -2020.

Scenario 6: Lower Load Forecast

This scenario examined the impact of the lower load forecast on the cost of congestion. The low load forecast is derived from the 2011 Gold Book, and is 9% lower than the 2011 Gold Book Baseline load forecast. The low load forecast is 30,734 MW and 31,819 MW respectively in 2015 and 2020. All other assumptions were the same as in the base case.

Scenario 7: Lower CO_2 Emission Costs

To simulate the potential impact of carbon emission costs lower than those modeled in the base case, this scenario assumed the price of CO_2 allowances to not exceed $5/ton throughout the 2011-2020 study period.

Scenario 8: Lower Natural Gas Prices

This scenario examines the cost of congestion when natural gas prices are projected to be lower than the base case levels by one standard deviation. The volatility of natural gas prices varies across the year such that it is most volatile in winter months and relatively stable during late spring. Consequently, as compared to the base case, the low price case can see January prices around 22% lower for Downstate and 12% lower for Upstate, while remaining about the same in May-June in both cases.

6. 2011 CARIS Findings – Study Phase

The CARIS study identified three study areas by considering monitored elements that have historically displayed high levels of congestion after adjusting for the effects of volatile fuel price changes and also considering the installation of new resources and transmission system improvements contained in the 2010 CRP. In order to estimate the economic impact of alleviating the identified congestion, the three generic solutions were applied to each of the three study areas and production costs savings were calculated based on the three different ranges of generic costs.

Table 6-1 shows the projected congestion for each of the three transmission groupings: Central East-New Scotland-Pleasant Valley, New Scotland-Pleasant Valley, and Leeds-Pleasant Valley.

Table 6-1: Base Case Projected Congestion 2011-2020

Study	Ten-Year Congestion ($M)	
	Nominal	Present Value (2011 $)
Study 1: Central East-New Scotland-Pleasant Valley	5,133	3,560
Study 2: New Scotland-Pleasant Valley	2,548	1,749
Study 3: Leeds-Pleasant Valley	2,535	1,741

The application of the generic solutions to the three study areas all result in production cost savings expressed in 2011 present values, as shown in Table 6-2.

Table 6-2: Production Cost Savings 2011-2020, Present Value in 2011 $M

	Ten-Year Production Cost Savings (2011 $M)		
Study	**Transmission Solution**	**Generation Solution**	**Demand Response Solution**
Study 1: Central East-New Scotland-Pleasant Valley	350	330	432
Study 2: New Scotland to Pleasant Valley	208	330	421
Study 3: Leeds - Pleasant Valley	154	330	421

In Phase 1, CARIS compares the present value of the production cost savings benefit over the ten-year study period to the present value of fixed costs based on a 16% carrying cost charge, for transmission and generation solutions, to determine a benefit/cost ratio, as presented in Table 6-3. A 16% carrying cost charge does not apply to demand response solutions. See Section 5.5 for a detailed explanation.

Table 6-3: Benefit/Cost Ratios

Study	Cost Ranges	Benefit/Cost Ratios		
		Transmission Solution	Generation Solution	Demand Response Solution
Study 1: Central East-New Scotland-Pleasant Valley	High	0.26	0.14	0.64
	Mid	0.38	0.18	0.80
	Low	0.95	0.23	1.06
Study 2: New Scotland to Pleasant Valley	High	0.36	0.14	0.56
	Mid	0.53	0.18	0.70
	Low	1.30	0.23	0.93
Study 3: Leeds to Pleasant Valley	High	0.43	0.14	0.56
	Mid	0.63	0.18	0.70
	Low	1.55	0.23	0.93

In conclusion, this CARIS Phase 1 study provides: (a) projections of congestion in the NYCA system; (b) present value of ten-year production cost savings ranging from $150M to $430M resulting from the application of various generic transmission, generation and demand response solutions; and (c) the Benefit/Cost ratios as high as 1.55 and as low as 0.14 depending on the high-medium-low generic project cost estimates.

Additionally, the scenario analyses provide information on new or increased projected congestion costs resulting from changes in variables selected for scenario analyses (see Table 5-23 in Section 5).

7. Next Steps

In addition to the CARIS Phase 1 Study, any interested party can request additional studies or use the CARIS Phase 1 results for guidance in submitting a request for a Phase 2 study.

7.1. Additional CARIS Studies

In addition to the three CARIS studies, any interested party may request an additional study of congestion on the NYCA bulk power system. Those studies can analyze the benefits of alleviating congestion with all types of resources, including transmission, generation and demand response, and compare benefits to costs.

7.2. Phase 2 – Specific Transmission Project Phase

The NYISO staff will commence Phase 2 – the Project Phase – of the CARIS process following the approval of the Phase 1 report by the NYISO Board. Phase 2 will provide a benefit/cost assessment for each specific transmission project that is submitted by developers who seek regulated cost recovery under the NYISO's Tariff.

Transmission projects seeking regulated cost recovery will be further assessed by NYISO staff to determine whether they qualify for cost allocation and cost recovery under the NYISO Tariff[11]. To qualify, the total capital cost of the project must exceed $25 million, the benefits must exceed the project cost measured over the first ten years from the proposed commercial operation date, and a super-majority ($\geq$ 80%) of the weighted votes cast by the beneficiaries must be in favor of the project. Additional details on the Phase 2 process can be found in Appendix F.

7.3. Project Phase Schedule

The NYISO staff will perform benefit/cost analysis for submitted economic transmission project proposals for and, if a developer seeks cost recovery, will determine beneficiaries and conduct cost allocation calculations. The results of the Phase 2 analyses will provide a basis for beneficiary voting on each proposed transmission project.

The next CARIS cycle will begin in 2013, upon the completion of the next CRPP cycle (approval of the 2012 CRP).

11 Market-based responses to congestion identified in Phase 1 of the CARIS are not eligible for regulated cost recovery, and therefore are not obligated to follow the requirements of Phase 2. Cost recovery of market-based projects shall be the responsibility of the developer.

Appendix A – Glossary

TERM	DEFINITION
Ancillary Services	Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or Voltage Support Service); Regulation Service; Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability. [FROM SERVICES TARIFF]
Bid Production Cost	Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (e.g., running cost, Minimum Generation Bid, and Start Up Bid). [FROM SERVICES TARIFF]
Bulk Power Transmission Facility (BPTF)	Transmission facilities that are system elements of the bulk power system which is the interconnected electrical system within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area.
Business Issues Committee (BIC)	A NYISO committee that is charged with, among other things, the responsibility to establish procedures related to the efficient and non-discriminatory operation of the electricity markets centrally coordinated by the NYISO, including procedures related to bidding, Settlements and the calculation of market prices.
Capacity	The capability to generate or transmit electrical power, or the ability to reduce demand at the direction of the NYISO.
Chicago Climate Futures Exchange (CCFE)	A derivatives exchange that offers standardized and cleared futures and options contracts on emission allowances and other environmental products.
Clean Air Markets Division (CAMD)	A division of the U.S. Environmental Protection Agency responsible for various market-based regulatory programs that are designed to improve air quality by reducing outdoor concentrations of fine particles, sulfur dioxide, nitrogen oxides, and mercury.
Comprehensive Reliability Plan (CRP)	An annual study undertaken by the NYISO that evaluates projects offered to meet New York's future electric power needs, as identified in the Reliability Needs Assessment (RNA). The CRP may trigger electric utilities to pursue regulated solutions to meet Reliability Needs if market-based solutions will not be available by that point. It is the second step in the Comprehensive Reliability Planning Process (CRPP)
Comprehensive Reliability Planning Process (CRPP)	The annual process that evaluates resource adequacy and transmission system security of the state's bulk electricity grid over a ten-year period and evaluates solutions to meet those needs. The CRPP consists of two studies: the RNA, which identifies potential problems, and the CRP, which evaluates specific solutions to those problems.

Comprehensive System Planning Process (CSPP)	A transmission system planning process that is comprised of three components: (1) Local transmission planning; (2) Compilation of local plans into the Comprehensive Reliability Planning Process (CRPP), which includes developing a Comprehensive Reliability Plan (CRP); (3) Channeling the CRP data into the Congestion Assessment and Resource Integration Study (CARIS)
Congestion	Congestion on the transmission system results from physical limits on how much power transmission equipment can carry without exceeding thermal, voltage and/or stability limits determined to maintain system reliability. If a lower cost generator cannot transmit its available power to a customer because of a physical transmission constraint, the cost of dispatching a more expensive generator is the congestion cost.
Congestion Rent	The opportunity costs of transmission Constraints on the NYS Bulk Power Transmission System. Congestion Rents are collected by the NYISO from Loads through its facilitation of LBMP Market Transactions and the collection of Transmission Usage Charges from Bilateral Transactions.
Contingencies	Electrical system events (including disturbances and equipment failures) that are likely to happen.
Day Ahead Market (DAM)	A NYISO-administered wholesale electricity market in which capacity, electricity, and/or Ancillary Services are auctioned and scheduled one day prior to use. The DAM sets prices as of 11 a.m. the day before the day these products are bought and sold, based on generation and energy transaction bids offered in advance to the NYISO. More than 90% of energy transactions occur in the DAM.
DC tie-lines	A high voltage transmission line that uses direct current for the bulk transmission of electrical power between two control areas.
Demand Response	A mechanism used to encourage consumers to reduce their electricity use during a specified period, thereby reducing the peak demand for electricity.
Eastern Interconnection Planning Collaborative (EIPC)	A group of planning authorities convened to establish processes for aggregating the modeling and regional transmission plans of the entire Eastern Interconnection and for performing inter-regional analyses to identify potential opportunities for efficiencies between regions in serving the needs of electrical customers.
Economic Dispatch of Generation	The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers.
Electric System Planning Working Group (ESPWG)	A NYISO governance working group for Market Participants designated to fulfill the planning functions assigned to it. The ESPWG is a working group that provides a forum for stakeholders and Market Participants to provide input into the NYISO's Comprehensive Reliability Planning Process (CRPP), the NYISO's response to FERC reliability-related Orders and other directives, other system planning activities, policies regarding cost allocation and recovery for reliability projects, and related matters.
Energy Efficiency Portfolio Standard (EEPS)	A statewide program ordered by the NYSPSC in response to the Governor's call to reduce New Yorkers' electricity usage by 15% of forecast levels by the year 2015, with comparable results in natural gas conservation. Also known as 15x15.

Exports	A Bilateral Transaction or purchases from the LBMP Market where the Energy is delivered to a NYCA Interconnection with another Control Area. [FROM SERVICES TARIFF]
External Areas	Neighboring Control Areas including HQ, ISO-NE, PJM, IESO
Federal Energy Regulatory Commission (FERC)	The federal energy regulatory agency within the US Department of Energy that approves the NYISO's tariffs and regulates its operation of the bulk electricity grid, wholesale power markets, and planning and interconnection processes.
FERC Form 715	An annual transmission planning and evaluation report required by the FERC – filed by the NYISO on behalf of the transmitting utilities in New York State.
FERC Order No. 890	Adopted by FERC in February 2007, Order 890 is a change to FERC's 1996 open access regulations (established in Orders 888 and 889). Order 890 is intended to provide for more effective competition, transparency and planning in wholesale electricity markets and transmission grid operations, as well as to strengthen the Open Access Transmission Tariff (OATT) with regard to non-discriminatory transmission service. Order 890 requires Transmission Providers – including the NYISO – have a formal planning process that provides for a coordinated transmission planning process, including reliability and economic planning studies.
Grandfathered Rights	The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party Transmission Wheeling Agreements (TWA) where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided in the Tariff, to retain those rights rather than to convert those rights to TCCs. [FROM SERVICES TARIFF]
Grandfathered TCCs	The TCCs associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party TWAs where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided by the Tariff, to convert those rights to TCCs. [FROM SERVICES TARIFF]
Grid View Software	An analytic tool for market simulation and asset performance evaluations.
Heat Rate	A measurement used to calculate how efficiently a generator uses heat energy. It is expressed as the number of BTUs of heat required to produce a kilowatt-hour of energy. Operators of generating facilities can make reasonably accurate estimates of the amount of heat energy a given quantity of any type of fuel, so when this is compared to the actual energy produced by the generator, the resulting figure tells how efficiently the generator converts that fuel into electrical energy.
High Voltage Direct Current (HVDC)	A transmission line that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current systems. For long-distance distribution, HVDC systems are less expensive and suffer lower electrical losses.
Investment Hurdle Rate	The minimum acceptable rate of return.
Imports	A Bilateral Transaction or sale to the LBMP Market where Energy is

	delivered to a NYCA Interconnection from another Control Area.
Independent Market Monitoring Unit	Consulting firm retained by the NYISO Board pursuant to Article 4 of the NYISO's Market Monitoring Plan.
Independent System Operator (ISO)	An organization, formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), which coordinates, controls and monitors the operation of the electrical power system, usually within a single US State, but sometimes encompassing multiple states.
Installed Capacity (ICAP)	A generator or load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity are available to meet the Reliability Rules.
Installed Reserve Margin (IRM)	The amount of installed electric generation capacity above 100% of the forecasted peak electric consumption that is required to meet New York State Reliability Council (NYSRC) resource adequacy criteria. Most planners consider a 15-20% reserve margin essential for good reliability.
Load	A term that refers to either a consumer of Energy or the amount of demand (MW) or Energy (MWh) consumed by certain consumers. [FROM SERVICES TARIFF]
Locational Capacity Requirement (LCR)	Locational Capacity Requirement specifies the minimum amount of installed capacity that must be procured from resources situated specifically within a locality (Zone K and Zone J). It considers resources within the locality as well as the transmission import capability to the locality in order to meet the resource adequacy reliability criteria of the New York State Reliability Council (NYSRC) and the Northeast Power Coordinating Council (NPCC).
Load Serving Entity (LSE)	Any entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail customers located within the NYCA, including an entity that takes service directly from the NYISO to supply its own Load in the NYCA. [FROM SERVICES TARIFF]
Load Zones	The eleven regions in the NYCA connected to each other by identified transmission interfaces. Designated as Load Zones A-K.
Local Transmission Planning Process (LTPP)	The first step in the Comprehensive System Planning Process (CSPP), under which stakeholders in New York's electricity markets participate in local transmission planning.
Locational Based Marginal Pricing (LBMP)	The price of Energy at each location in the NYS Transmission System.
Market Analysis and Portfolio Simulation (MAPS) Software	An analytic tool for market simulation and asset performance evaluations.
Multi-Area Reliability Simulation (MARS) Software	An analytic tool for market simulation to assess the reliability of a generation system comprised of any number of interconnected areas.

Market Based Solution	Investor-proposed projects that are driven by market needs to meet future reliability requirements of the bulk electricity grid as outlined in the RNA. Those solutions can include generation, transmission and Demand Response Programs.
Market Participant	An entity, excluding the NYISO, that produces, transmits sells, and/or purchases for resale capacity, energy and ancillary services in the wholesale market. Market Participants include: customers under the NYISO's tariffs, power exchanges, Tos, primary holders, load serving entities, generating companies and other suppliers, and entities buying or selling transmission congestion contracts.
New York Control Area (NYCA)	The area under the electrical control of the NYISO. It includes the entire state of New York, and is divided into 11 zones.
New York Independent System Operator (NYISO)	Formed in 1997 and commencing operations in 1999, the NYISO is a not-for-profit organization that manages New York's bulk electricity grid – a 10,775-mile network of high voltage lines that carry electricity throughout the state. The NYISO also oversees the state's wholesale electricity markets. The organization is governed by an independent Board of Directors and a governance structure made up of committees with Market Participants and stakeholders as members.
New York State Reliability Council (NYSRC)	A not-for-profit entity whose mission is to promote and preserve the reliability of electric service on the New York State Power System by developing, maintaining, and, from time-to-time, updating the Reliability Rules which shall be complied with by the New York Independent System Operator (NYISO) and all entities engaging in electric transmission, ancillary services, energy and power transactions on the New York State Power System.
Nomogram	Nomograms are used to model relationships between system elements. These can include; voltage or stability related to load level or generator status; two interfaces related to each other; generating units whose output is related to each other; and operating procedures.
Northeast Coordinated System Planning Protocol (NCSPP)	ISO New England, PJM and the NYISO work together under the Northeast Coordinated System Planning Protocol (NCSPP), to analyze cross-border issues and produce a regional electric reliability plan for the northeastern United States.
Operating Reserves	Capacity that is available to supply Energy or reduce demand and that meets the requirements of the NYISO. [SERVICES TARIFF TERM]
Overnight Costs	Direct permitting, engineering and construction costs with no allowances for financing costs.
Phase Angle Regulator (PAR)	Device that controls the flow of electric power in order to increase the efficiency of the transmission system.
Proxy Generator Bus	A proxy bus located outside the NYCA that is selected by the NYISO to represent a typical bus in an adjacent Control Area and for which LBMP prices are calculated. The NYISO may establish more than one Proxy Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services at the Interface.
Regional Greenhouse Gas Initiative (RGGI)	A cooperative effort by ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions using a market-based cap-and-trade approach.

Regulated Backstop Solution	Proposals required of certain TOs to meet Reliability Needs as outlined in the RNA. Those solutions can include generation, transmission or dDemand rResponse. Non-Transmission Owner developers may also submit regulated solutions. The NYISO may call for a Gap solution if neither market-based nor regulated backstop solutions meet Reliability Needs in a timely manner. To the extent possible, the Gap solution should be temporary and strive to ensure that market-based solutions will not be economically harmed. The NYISO is responsible for evaluating all solutions to determine if they will meet identified Reliability Needs in a timely manner.
Regulation Service	An Ancillary Service. See glossary definition for Ancillary Services.
Reliability Need	A condition identified by the NYISO in the RNA as a violation or potential violation of Reliability Criteria. (OATT TERM)
Reliability Needs Assessment (RNA)	An annual report that evaluates resource adequacy and transmission system security over a ten-year planning horizon, and identifies future needs of the New York electric grid. It is the first step in the NYISO's CRPP.
Security Constrained Unit Commitment (SCUC)	A process developed by the NYISO, which uses a computer algorithm to dispatch sufficient resources, at the lowest possible Bid Production Cost, to maintain safe and reliable operation of the NYS Power System.
Special Case Resource (SCR)	A NYISO demand response Demand Response program designed to reduce power usage by businesses and large power users qualified to participate in the NYISO's ICAP market. Companies that sign up to serve as SCRs are paid in advance for agreeing to reduce power consumption upon NYISO request.
Stakeholders	A person or group that has an investment or interest in the functionality of New York's transmission grid and markets.
Thermal transfer limit	The maximum amount of heat a transmission line can withstand. The maximum reliable capacity of each line, due to system stability considerations, may be less than the physical or thermal limit of the line.
Transfer Capability	The amount of electricity that can flow on a transmission line at any given instant, respecting facility rating and reliability rules.
Transmission Congestion Contract (TCC)	The right to collect, or obligation to pay, Congestion Rents in the Day Ahead Market for Energy associated with a single MW of transmission between a specified Point Of Injection and Point Of Withdrawal. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission. (SERVICES TARIFF TERM)
Transmission Constraint	Limitations on the ability of a transmission facility to transfer electricity during normal or emergency system conditions.
Transmission District	The geographic area served by the Investor Owned Transmission Owners and LIPA, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York. (SERVICES TARIFF TERM)
Transmission Interface	A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas. (SERVICES TARIFF TERM)

Transmission Owner (TO)	A public utility or authority that provides Transmission Service under the Tariff
Transmission Planning Advisory Subcommittee (TPAS)	A group of Market Participants that advises the NYISO Operating Committee and provides support to the NYISO Staff in regard to transmission planning matters including transmission system reliability, expansion, and interconnection.
Unhedged Congestion	Congestion payment (congestion component times load affected) minus the TCC hedge.[Add definition]