2017 CARIS REPORT

Congestion Assessment and Resource Integration Studies

A Report by the New York Independent System Operator

February 2018

2017 Congestion Assessment and Resource Integration Study

Comprehensive System Planning Process

CARIS - Phase 1

A Report by the
New York Independent System Operator

March 28, 2018

Caution and Disclaimer

NYISO System Resources and Planning staff can be reached at 518-356-6000 to address any questions regarding this CARIS report or the NYISO’s economic planning processes.

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Executive Summary

Overview

With the publication of this 2017 Congestion Assessment and Resource Integration Study (CARIS) Phase 1 Report, the New York Independent System Operator, Inc. (NYISO) has completed the first phase (CARIS Phase 1) of its two-phase economic planning process.[1] This CARIS Phase 1 report provides information to market participants, policy makers, and other interested parties for their consideration in evaluating projects designed to address congestion costs identified in the study. The report presents an assessment of historic (2012-2016) and projected (2017-2026) congestion on the New York State bulk power transmission system and provides an analysis of the potential costs and benefits of relieving that congestion using generic transmission, generation, demand response, and energy efficiency solutions to mitigate the identified congestion.

The study presents a series of metrics for a wide-range of potential futures and scenarios. One set of results can be viewed as a "business as usual" case, incorporating incremental resource changes based on the NYISO's study inclusion rules. These results, while informative to a degree, are borne of a resource rich landscape with limited load growth, and mirror past studies in identifying limited opportunities for transmission build-out based solely on production-cost reductions. A second set of results[2] is more forward-looking and captures impacts of global changes on the New York electric system that are exemplified by the achievement of New York's Clean Energy Standard through large-scale growth in renewable resources and implementation of energy-efficiency programs. It is these second set of results which provides the greater value in understanding future system congestion and the associated opportunities for economic investment in solutions.

The Six Congestion Studies

Consistent with the CARIS procedures, the NYISO identified the three elements or groups of elements where congestion was most prevalent in the NYCA based on an analysis of historic and projected congestion, and potential production cost savings. In order to provide additional relevant information to stakeholders, three additional studies were performed off of the primary cases. Edic-Marcy was relaxed in two of the study cases for analyses purposes because of the limited upgrades that would be required to eliminate this constraint and the significant downstream impacts and opportunities created by doing so.

1 Capitalized terms not otherwise defined herein have the meaning set forth in Section 1 and Attachment Y of the NYISO's OATT.

2 This second set of results is presented as the System Resource Shift case.

The six studies specifically are:

a) Study 1: Central East-Edic-Marcy

b) Study 2: Central East

c) Study 3: Central East- New Scotland- Pleasant Valley

d) Study 4: Study 3 with Edic- Marcy relaxed

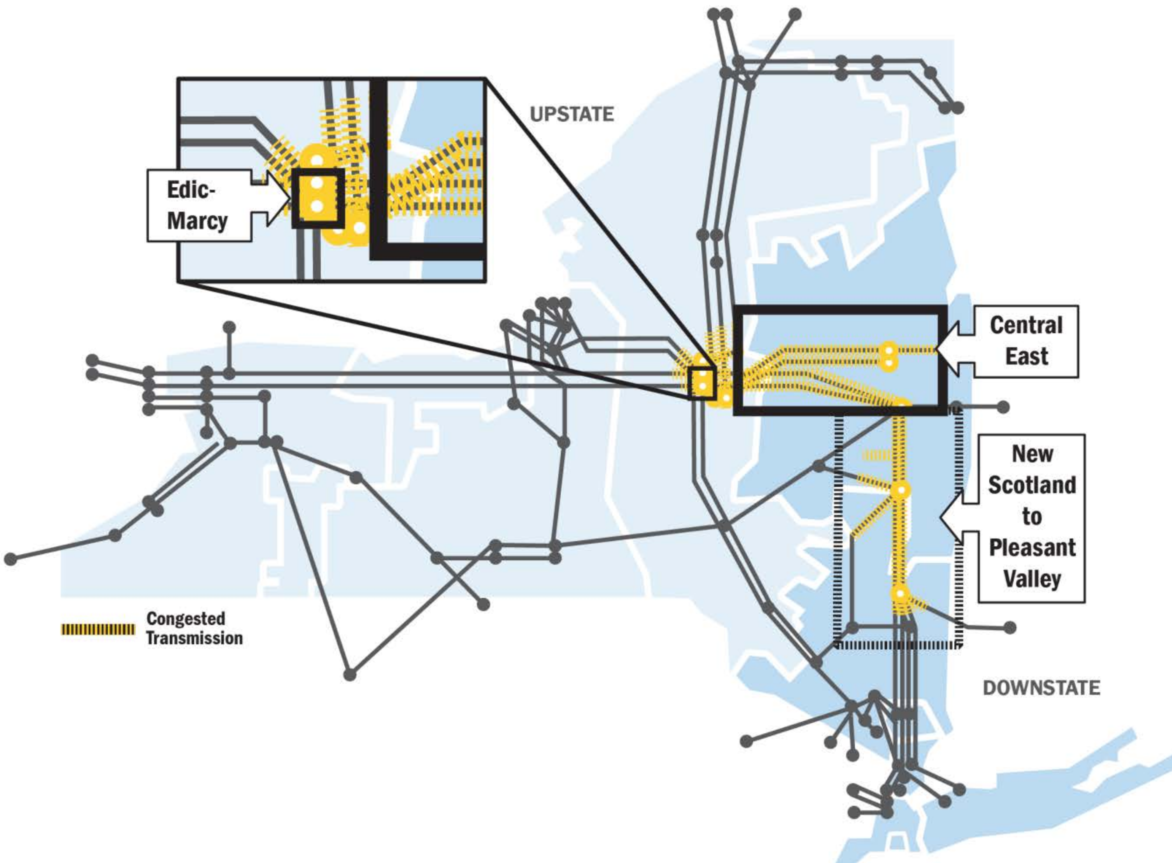
e) Study 5: Study 3 under the System Resource Shift Case[3]

f) Study 6: Study 5 with Edic-Marcy relaxed.

The groupings selected for the six 2017 CARIS studies are shown in Figure 1 along with the present value of projected congestion. For analysis purposes, both the Base Case and Solution Cases in Studies 4 and 6 relax the Edic-Marcy constraint.

3 The System Resource Shift Case reflects achievement of New York's Clean Energy Standard (CES), the retirement of NYCA coal units, and the Indian Point 2 and 3 units. The CES requires that 50 percent of New York's electricity come from renewable energy sources such as solar and wind by 2030. For the purpose of this study, the CES goals were modeled as being achieved in 2026, the final year of the study period, in order to provide the most complete picture of the impact of CES achievement on the NYCA.

Figure 1: Congestion on the CARIS Groupings (Present Value in $2017M)



Study 1: Central East-Edic-Marcy	**Study 4: Study 3 with Edic-Marcy relaxed**
Demand$ Congestion: 2,023 ($2017M)	Demand$ Congestion: 2,596 ($2017M)
Study 2: Central East	**Study 5: Study 3 under System Resource Shift Case**
Demand$ Congestion: 1,966 ($2017M)	Demand$ Congestion: 3,384 ($2017M)
Study 3: Central East-New Scotland-Pleasant Valley	**Study 6: Study 5 with Edic-Marcy relaxed**
Demand$ Congestion: 1,983 ($2017M)	Demand$ Congestion: 4,130 ($2017M)

Key Study Assumptions

The study assumptions were developed with Stakeholders subject to the CARIS procedures, based upon the best information available when the database was locked down in August 2017. Different assumptions, based on more recently available data, may impact the study results. The alternate studies and scenarios studied provide additional insights on how congestion patterns and economic impacts may be mitigated by additional infrastructure.

Non-Resource Changes Since Last CARIS – Among the notable changes made in input assumptions and system modeling since the prior CARIS are:

a) Conforming the modeling of the PJM/NYISO interface to the current NY-PJM Joint Operating Agreement

b) Seasonal (winter) by-pass of the Marcy South Series Compensation (MSSC)

Resource Assumptions - The ten-year assessment of future congestion and the potential benefits of relieving some of this congestion are based upon the NYCA resources that were included in the base case for the 2016 Comprehensive Reliability Plan (CRP) adjusted to reflect the NYISO's base case inclusion rules and the August 2017 lock-down. There are several key assumptions that must be considered in reviewing the results for Studies 1 – 4. These include:

a) Indian Point Energy Center is modeled as in-service

b) FitzPatrick and Ginna are modeled as in-service

c) Greenidge 4, and Cayuga 1 and 2 and are modeled as in-service

d) Four new wind farms are modeled as in-service in Upstate New York

e) CPV Valley and the Bayonne Expansion project are modeled as coming on-line in 2018

f) Cricket Valley Energy Center is modeled as coming on-line in 2019

Studies 5 and 6 were performed with a materially different set of resources than Studies 1 – 4. Specifically, Indian Point Energy Center and all New York coal units are modeled as retired. In addition, implementation of the Clean Energy Standard was modeled as 4.6GW of on-shore wind, 10.8GW of utility-scale solar and 0.25 GW of off-shore wind in-service by 2026[4], which in total annually produces 28.5 TWh of renewable energy. This was supplemented with annual energy reductions of 10.5 TWh due to energy efficiency.

4 NYS Department of Public Service, *Staff White Paper on Clean Energy Standard (CASE 15-E-0302),* January 25, 2016.

Solutions

Tariff provisions direct that the CARIS analysis study four solution types for each of the selected studies and that the studied solutions be considered on a comparable basis. Toward this end, the NYISO sizes the solutions such that the megawatts of generation, demand response and energy efficiency approximate the increase in transfer capability across the relevant interface created by the transmission solution. For Study 1 and 2, this resulted in an increased transfer capability of approximately 600 MW across Central East; for Studies 3 through 6, this resulted in an increased transfer capability of approximately 700 MW across Central East and an increase of 1,200 MW across UPNY-SENY. Figure 2 presents a summary of the solution sizes.

Figure 2: Generic Solutions

Generic Solutions						
Studies	**Central East-Edic-Marcy (Study 1)**	**Central East (Study 2)**	**Central East-New Scotland-Pleasant Valley (Study 3)**	**Central East-New Scotland-Pleasant Valley (Study 4)**	**Central East-New Scotland-Pleasant Valley (Study 5)**	**Central East-New Scotland-Pleasant Valley (Study 6)**
TRANSMISSION						
Transmission Path	Marcy-New Scotland	Edic-New Scotland	Edic-New Scotland-Pleasant Valley	Edic-New Scotland-Pleasant Valley	Edic-New Scotland-Pleasant Valley	Edic-New Scotland-Pleasant Valley
Voltage	345 kV	345 kV	345 kV	345 kV	345 kV	345 kV
Miles	85	85	150	150	150	150
GENERATION						
Unit Siting	New Scotland	New Scotland	Pleasant Valley	Pleasant Valley	Pleasant Valley	Pleasant Valley
# of 340 MW Blocks	2	2	4	4	4	4
DEMAND RESPONSE						
Location (# of Blocks)	F(1), G(1) and J(1)	F(1), G(1) and J(1)	F(1), G(1) and J(4)	F(1), G(1) and J(4)	F(1), G(1) and J(4)	F(1), G(1) and J(4)
Total # of 200MW Blocks	3	3	6	6	6	6
ENERGY EFFICIENCY						
Location (# of Blocks)	F(1), G(1) and J(1)	F(1), G(1) and J(1)	F(1), G(1) and J(4)	F(1), G(1) and J(4)	F(1), G(1) and J(4)	F(1), G(1) and J(4)
Total # of 200MW Blocks	3	3	6	6	6	6

The impact of each solution was estimated on the base-level of congestion costs for each grouping for each solution as shown in Figure 3.

Figure 3: NYCA Demand-Congestion Impacts ($2017M)

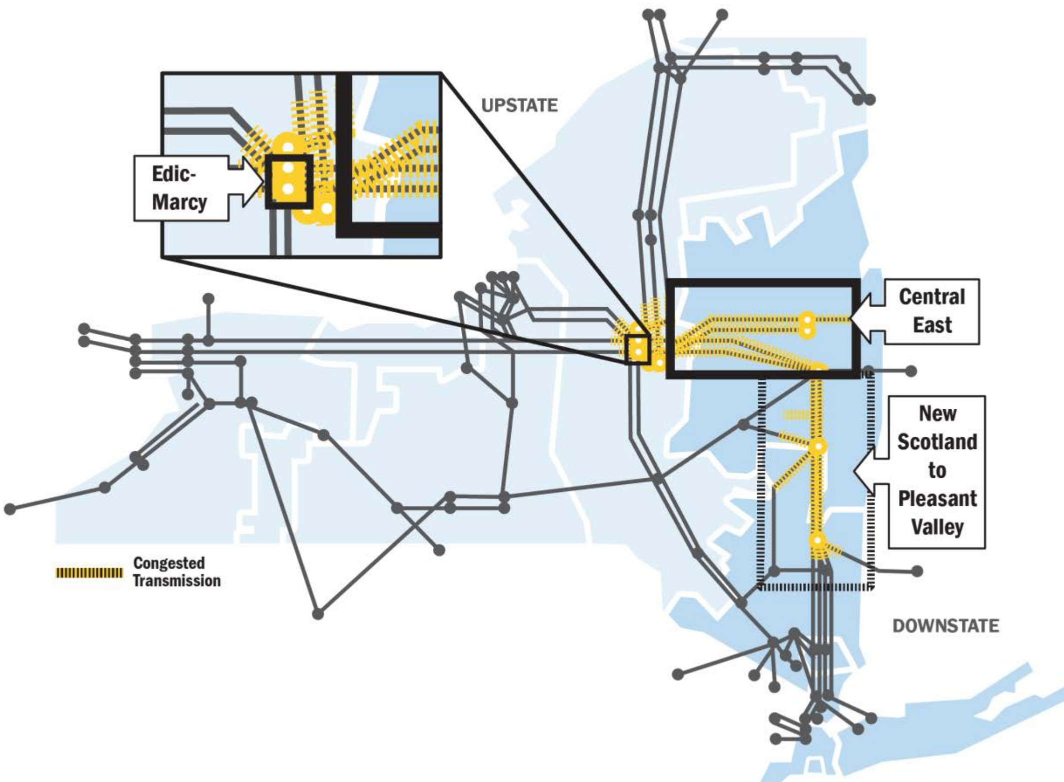
Study	Base Case	Transmission	Generation	Demand Response	Energy Efficiency
Study 1: Central East-Edic-Marcy	6,492	(1,300)	37	(19)	(316)
Study 2: Central East	6,492	(914)	37	(19)	(316)
Study 3: Central East-New Scotland-Pleasant Valley	6,492	(1,091)	(33)	(53)	(720)
Study 4: Study 3 with Edic-Marcy relaxed	6,780	(1,707)	33	(44)	(737)
Study 5: Study 3 under System Resource Shift Case	9,834	(1,956)	(94)	(59)	(923)
Study 6: Study 5 with Edic-Marcy relaxed	10,182	(2,398)	(64)	(51)	(957)

Costs for each type of generic solution were presented through the stakeholder process. Recognizing that the costs, points of interconnection, timing, and characteristics of actual projects may vary significantly, a range of costs (low, mid and high) was developed for each type of resource based on publicly available sources. Such costs may differ from those submitted by potential developers in a competitive bidding process. Mid-level costs were in the range of $463M to $818M for transmission; $1.2B to $2.7B for generation; $320M to $980M for demand-response; and $1.2B to $2.9B for energy-efficiency.

The change in NYCA production costs attributable to the generic solutions was estimated for each of the six studies as shown in Figure 4. Aggregate electric production costs of New York generators over the Study Period are projected to range between $2B and $4B annually.[5]

5 Production costs are estimated based on projected unit-specific variable costs not historic generator bids.

Figure 4: NYCA-wide Production Cost Savings ($2017M)



Study 1: Central East-Edic-Marcy	
Solution	**Production Cost Savings ($2017M)**
Transmission	149
Generation	84
Demand Response	27
Energy Efficiency	845

Study 4: Study 3 with Edic-Marcy relaxed	
Solution	**Production Cost Savings ($2017M)**
Transmission	197
Generation	159
Demand Response	54
Energy Efficiency	1,728

Study 2: Central East	
Solution	**Production Cost Savings ($2017M)**
Transmission	124
Generation	84
Demand Response	27
Energy Efficiency	845

Study 5: Study 3 under System Resource Shift Case	
Solution	**Production Cost Savings ($2017M)**
Transmission	298
Generation	204
Demand Response	55
Energy Efficiency	1,689

Study 3: Central East-New Scotland-Pleasant Valley	
Solution	**Production Cost Savings ($2017M)**
Transmission	185
Generation	152
Demand Response	55
Energy Efficiency	1,696

Study 6: Study 5 with Edic-Marcy relaxed	
Solution	**Production Cost Savings ($2017M)**
Transmission	319
Generation	211
Demand Response	56
Energy Efficiency	1,700

Scenario Analysis

The NYISO conducted scenario analyses to evaluate the impact on congestion of changed conditions in the base case assumptions. Scenario analysis can provide useful insight on the sensitivity of projected congestion values to differing assumptions included in the base case. The scenarios were selected by the NYISO in collaboration with its stakeholders. The scenarios modify the base case to address variations from the base forecasts of electric demand, fuel and emission prices, and an aggregated set of Public Policy initiatives (e.g., Western NY Public Policy and AC Transmission projects, and the CES) for the last year of the study, 2026.[6] Figure 5 lists major assumptions used for each scenario; and Figure 6 shows the impact on congestion in 2026 for each scenario in 2017 dollars. Negative values represent a reduction in congestion impact measured by Demand$ Congestion, where Demand$ Congestion is a measure of the congestion component of the LBMP and its impact on NYCA loads. It represents the cost of congestion to consumers. Figure 7 below presents a summary of how each of the three transmission groupings chosen for study is affected by each of the scenarios for 2026.

Figure 5: Major Scenario Assumptions

Scenario	Description
Higher Load Forecast	Higher Growth Rate (net increase of 5 TWh from base forecast)
Lower Load Forecast	Lower Growth Rate (net decrease of 5 TWh from base forecast)
Higher Natural Gas Prices	Derived from 2017 EIA AEO High Forecast
Lower Natural Gas Prices	Derived from 2017 EIA AEO Low Forecast
National CO_2 Program	RGGI Carbon pricing applied to Non-RGGI states
Public Policy (SRS/Transmission)	Selected project for Western NY Public Policy Transmission Need (PPTN) and generic segments A and B for AC Transmission PPTN under the System Resource Shift Case (Achievement of "50 by 30" objectives by 2026 - Energy Efficiency, Solar, On-Shore and Off-Shore Wind / retirement of NYCA Coal Units / retirement of IPEC)

6 For each scenario the base case used for comparison was the base case developed for Studies 1-3.

Figure 6: Scenarios Impact on Congestion: Horizon Year ($2017M)

Constraints	Scenarios: Change in 2026 Demand$ Congestion from Base Case ($2017M)						
	High Load Forecast	Low Load Forecast	High Natural Gas Prices	Low Natural Gas Prices	National CO_2 Program	System Resource Shift Case	Public Policy (SRS / Transmission)
Central East-Edic-Marcy	(16)	17	197	(53)	(31)	424	168
Central East	(17)	17	197	(54)	(32)	425	169
Central East-New Scotland-Pleasant Valley	(17)	18	197	(54)	(32)	451	167

Figure 7: Impact on Demand$ Congestion

Constraints	Scenarios: Change in 2026 Demand$ Congestion from Base Case (%)						
	High Load Forecast	Low Load Forecast	High Natural Gas Prices	Low Natural Gas Prices	National CO_2 Program	System Resource Shift Case	Public Policy (SRS / Transmission)
Central East-Edic-Marcy	-13%	14%	161%	-43%	-25%	348%	138%
Central East	-14%	14%	163%	-45%	-26%	351%	140%
Central East-New Scotland-Pleasant Valley	-14%	15%	159%	-44%	-26%	364%	135%

Key Findings

- The results for the "business as usual" case are consistent with those in prior CARIS studies in which the solutions studied offered a measure of congestion relief and production costs savings, but did not result in generic transmission projects with B/C ratios in excess of 1.0 utilizing the generic cost estimates.
- The Central East-Pleasant Valley Transmission Solution, however, produced significantly higher production costs and demand congestion savings when studied with a resource mix driven by the Clean Energy Standard. Production costs reductions were 61% higher; and Demand$ Congestion savings 79% higher. This additional transfer capability across Central East and UPNY-SENY did materially increase the access of Upstate renewable resources to the downstream markets.
- The importance of the interplay between the CES and transmission expansion is indicated as well by the results of the SRS case and Public Policy scenario analyses for 2026. Congestion for the SRS case (of which the CES is a prime component) across the Central East-New Scotland-Pleasant Valley corridor is approximately $450M higher in 2026 than the base system ($124M vs. $574M) as renewable resources are bottled Upstate. Spillage for solar and wind resources – the curtailment of renewable generation due to transmission constraints – is nearly non-existent in the 2026 BAU case but increases to 1.2 TWh in the SRS case. As expected, the output from NY renewable resources in the SRS case increase dramatically from the BAU case (nearly

28 TWh in 2026)[7]. There was, however, a reduction of 0.7 TWh in nuclear output from the BAU case to the SRS case[8]. Finally, net imports from PJM, IESO and ISO-NE decrease in the SRS case (from the BAU) case by 14 TWh, as New York exports a portion of the increased renewable energy to its neighbors.

- The build-out of the Western and AC Transmission projects has a significant impact on how the SRS case affects a number of key metrics. It reduces the higher congestion observed in the SRS case in the Central East-New Scotland-Pleasant Valley corridor by $284M. The additional transmission in the Public Policy scenario increases the renewable energy production by an incremental 0.5 TWh from the SRS case; and the output from upstate nuclear units by 0.4 TWh. This scenario also resulted in a reduction of 1.6 TWh in output from gas-fired generation located in Zones F – K. Finally, overall net imports increase by less than 0.3 TWh (as exports decrease) between the SRS case and the Public Policy scenario.
- The spillage of renewable solar and wind resources in the SRS case and Public Policy Scenario is due to constraints on the bulk-power system and is not reflective of transmission limitations present on the lower-voltage system (e.g., the 115 kV system in upstate zones). The spillage identified can therefore be considered a lower bound and would only be exacerbated should the lower voltage system be monitored and secured in the commitment and dispatch processes.

Next Steps

Additional Study Requests

Going forward, any interested party can request, at its own expense, an additional study to assess a specific project and its impact on congestion on the New York bulk power system. The NYISO will conduct the requested studies in the order in which they were accepted and as the NYISO's resource commitments allow.

Specific Project Analysis

Phase 2 of the CARIS process is expected to begin in April 2018, subject to the approval of this 2017 CARIS Phase 1 report by the NYISO Board of Directors. In Phase 2, developers are encouraged to propose projects to alleviate the identified congestion. The NYISO will evaluate proposed specific

7 Production from those renewable resources added in the SRS case displaced 257 GWh of production from existing wind resources; 68 GWh from solar units; and 2 GWh from hydroelectric units.

8 In the context of this study, the reduced output from nuclear units can be viewed as a proxy for lower output from renewable resources resulting from curtailment of either existing or new renewable resources. The NYISO is exploring alternative modeling constructs for fixed units and hourly modifiers that would make this trade-off more explicit in future studies.

economic transmission projects upon a developer's request to determine the extent such projects alleviate congestion, and whether the projected economic benefits would make the project eligible for cost recovery under the NYISO's Tariff. While the eligibility criterion is production cost savings, zonal LBMP load savings (net of TCC revenues and bilateral contracts) is the metric used in Phase 2 for the identification of beneficiary savings and the determinant used for cost allocation to beneficiaries for a transmission project.

For a transmission project to qualify for cost recovery through the NYISO's Tariff, the project has to have:

a) a capital cost of at least $25 million,

b) benefits that outweigh costs over the first ten years of operation, and

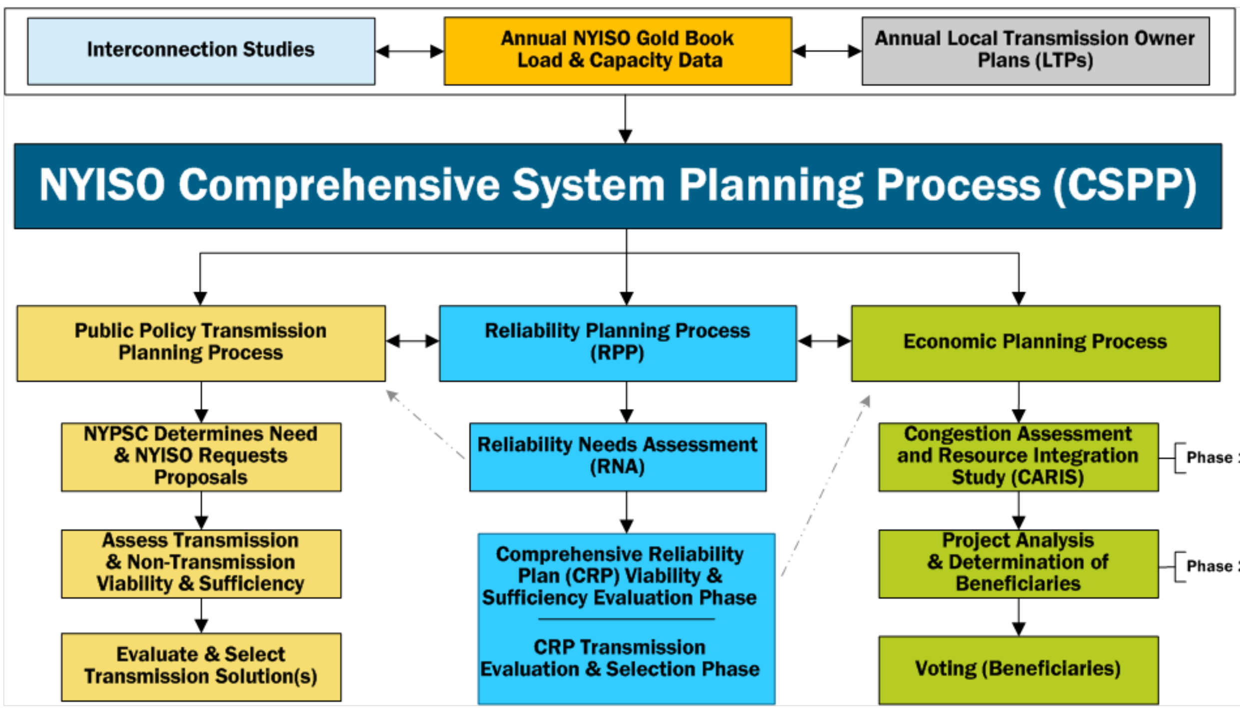
c) received approval to proceed from 80% or more of the actual votes cast by beneficiaries on a weighted basis.

Having met these conditions, the developer will be able to obtain cost recovery of their transmission project through the NYISO's Tariff, subject to the developer's filing with the Federal Energy Regulatory Commission (FERC) for approval of the project costs and rate treatment.

Introduction

Pursuant to Attachment Y of the NYISO Open Access Transmission Tariff (OATT, or the Tariff), the NYISO performed the first phase of the 2017 Congestion Assessment and Resource Integration Study (CARIS). CARIS is the primary component of the NYISO's Economic Planning Process (EPP) which is one of the three processes that now comprise the NYISO's Comprehensive System Planning Process (CSPP) (see Figure 8). The study assesses both historic and projected congestion on the New York bulk power system and estimates the economic benefits of relieving congestion.

Figure 8: NYISO Comprehensive System Planning Process



This final Report documents the methodologies and baseline assumptions used in identifying the congested pathways. It presents how the baseline metrics such as system-wide production cost are impacted by solutions to the baseline congestion. These solutions can be considered as upgrades in system topology (new transmission lines), system resource composition (new generation facilities), and system load characteristics (incremental demand response and energy efficiency). The Report concludes with a comparison of the benefits of such generic solutions with high-level cost estimates.

The 2017 CARIS Phase 1 study also provides important insights into how projected system congestion would be impacted by alternate study assumptions. Unlike prior studies, the NYISO went beyond the Tariff-required three studies and performed three supplemental studies – including two studies addressing major resource shifts in New York - in order to provide its stakeholders with additional insights into NYCA congestion patterns under system conditions varying from the baseline. These full ten-year (2017-2026) studies compliment the base ten-year studies as well as the more limited, single-year (2026) assessment of alternate assumptions, or scenarios.

This Report documents 2017 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, generation, demand response, or energy efficiency projects. Developers of any type of solution may choose to pursue a project on a merchant basis, or to enter into bi-lateral contracts with Load-Serving Entities (LSEs) or other parties. Only those Developers proposing transmission solutions to the identified congestion may seek cost-recovery through the NYISO Tariff in the CARIS Phase 2 process. This report does not make recommendations for specific projects, and does not advocate any specific type of resource addition or other actions.

The projected congestion in this report will be different than the 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 cost estimates was used to calculate the cost of generic solution projects (transmission, generation, demand response, and energy efficiency). These costs are intended for illustrative purposes only and are not based on any feasibility analyses. Each of the generic solution costs are utilized in the development of benefit/cost ratios.

The NYISO Staff presented the Phase 1 Study results in a written draft report to the 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 NYISO's Board of Directors for approval.

Background

Congestion Assessment and Resource Integration Study (CARIS) Process

The objectives of the CARIS economic planning process are to:

a. Project congestion on the New York State Bulk Power Transmission Facilities (BPTFs) over the ten-year CSPP planning horizon;

b. Identify, through the development of appropriate scenarios, factors that might affect congestion;

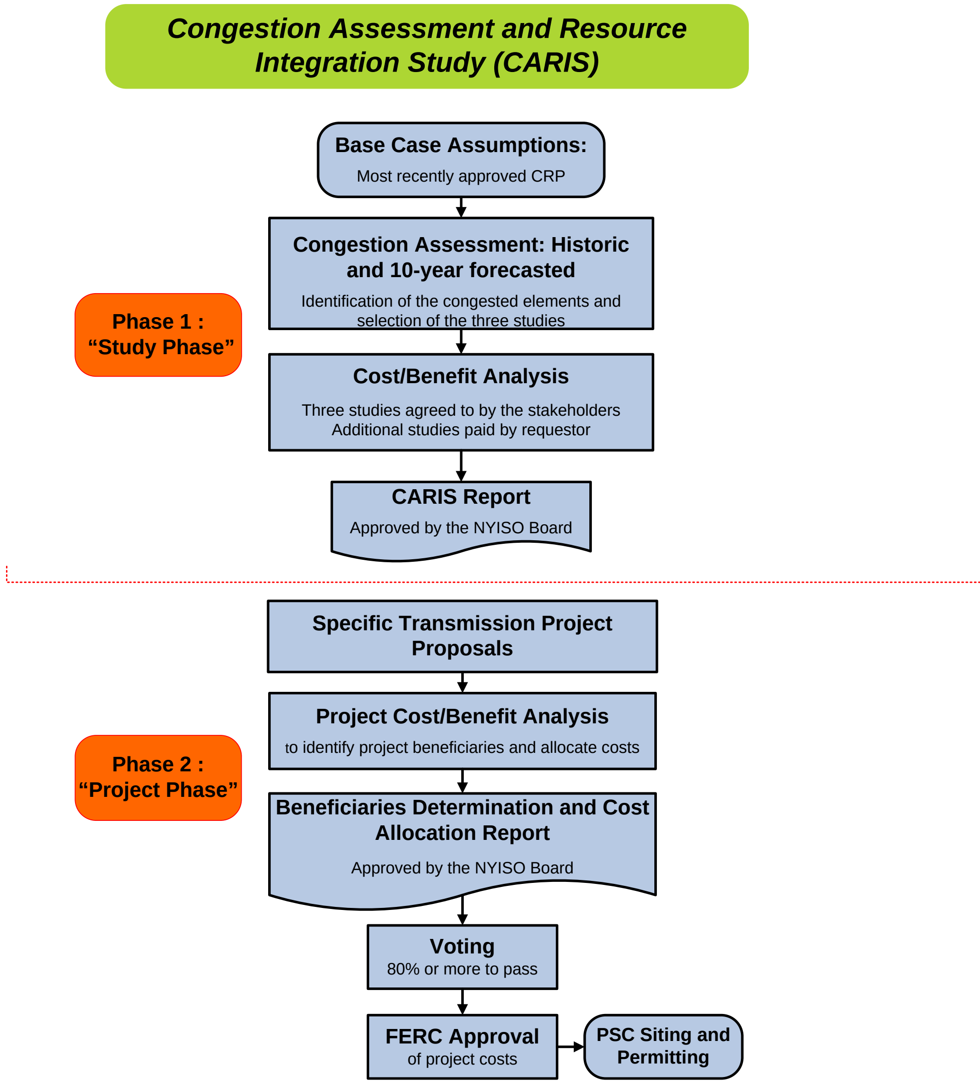
c. Provide information to Market Participants, stakeholders and other interested parties on solutions to reduce congestion and to create production cost savings which are measured in accordance with the Tariff requirements;

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 9 below.

Figure 9: Overall CARIS Diagram



Phase 1 - Study Phase

Phase 1 of the CARIS process is initiated after the viability and sufficiency phase of the CRP is completed (or upon NYISO Board approval of the CRP should no Reliability Needs be identified in the RNA). The NYISO, in collaboration with Market Participants, identifies the most congested elements in the New York bulk power system and conducts transmission congestion studies based on those elements. 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 most congested elements and, through a relaxation process, develops potential groupings and rankings based on the highest projected production cost savings resulting from the relaxation. The NYISO Tariff calls for the top three ranked elements or groupings to be studied.[9] For each of these studies the NYISO conducts a benefit/cost analysis of generic solutions. All resource types - generation, transmission, demand response, and energy efficiency - are considered on a comparable basis as generic solutions to congestion. The solutions analyzed are not specific projects, but rather represent generic transmission, generation, demand response, and energy efficiency resources placed individually in the congested locations on the system to calculate their effects on relieving each of the three most congested elements and the resulting economic benefits.

The principal metric for measuring the economic benefits of 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. Each of the CARIS metrics is described in more detail in the "CARIS Methodology and Metrics" section below..

The NYISO also conducts scenario analyses to assess the congestion impact of various changes to base case assumptions. Scenario results are presented as the change in system congestion on the three study elements or groupings, as well as other constraints throughout NYCA.

Phase 2 – Regulated Economic Transmission Project (RETP) Cost Allocation Phase

The Phase 2 model will be developed from the CARIS 1 database using an assumption matrix developed after discussion with ESPWG and with the concurrence of the Business Issues Committee. The Phase 2 database will be updated, consistent with the CARIS manual, to reflect all appropriate and agreed upon system modeling changes required for a 10 year extension of the model. 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.

Developers of 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

9 As noted below, the NYISO went beyond the requirements of the Tariff in the 2017 CARIS Phase 1 and performed three additional studies to enhance the overall value of this phase of the economic process.

by the Tariff. Projects may be eligible for regulated cost recovery only if the present value of the NYCA-wide production cost savings exceeds the present value of the costs over the first ten years of the project life. In addition, 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 those 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 LSEs 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. Once the project is placed in-service, cost recoveries within a zone will be allocated according to each LSE's zonal MWh load ratio share.

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 auction revenues and allocation of congestion rents to the TOs (for more detail on this metric see the "CARIS Methodology and Metrics" section of this report and the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual[10].)

The NYISO will also analyze and present additional information by conducting scenario analyses, at the request of the Developer after discussions with ESPWG, regarding future uncertainties such as energy and peak demands, fuel prices and emission allowance costs, as well as other qualitative impacts such as improved system operations, potential environmental

10See http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/epp_caris_mnl.pdf regulations, and public policies supporting the integration of renewable 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. Thereafter 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 of Directors 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 3.4.5 of the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual). 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 approval of the project costs which were presented by the Developer to the voting beneficiaries and with the appropriate state authorities to obtain siting and permitting approval for the project.

CARIS Methodology and Metrics

CARIS Methodology

The first step in the CARIS process is the development of a 15-year assessment of congestion on the NYISO transmission system, comprised of a ten-year look ahead and a five-year look back. For the purposes of conducting the ten-year forward-looking CARIS analysis, the NYISO utilized the GE's Multi-Area Production Simulation (MAPS) software executed with a production cost database developed in consultation with the ESPWG. The details and assumptions in developing this database are summarized in Appendix C.

Since 2012, the NYISO has utilized an off-line version of the NYISO's production Security Constrained Unit Commitment software (SCUC), entitled Congestion Reporting for Off-Line SCUC (CROS), to perform its historic congestion analyses. CARIS utilizes the most recent five years of historic data. Unlike MAPS simulation, CROS recognizes historic virtual bidding and transmission outages and calculates production costs based on mitigated generation 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.

CARIS Metrics

The principal benefit metric for the CARIS Study Phase analysis is the NYCA-wide production cost savings 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 informational purposes only. All benefit metrics were determined by measuring the difference between the projected CARIS base case value and a projected solution case value when each generic solution was added. The discount rate of 6.99% used for the present value analysis was the current Weighted Average Cost of Capital (WACC) for the New York Transmission Owners, weighted by their annual GWh load in 2016.

One of the key metrics in the CARIS analysis is termed Demand Dollar Congestion (Demand$ Congestion). Demand$ Congestion represents the congestion component of load payments which ultimately represents the cost of congestion to consumers. For a Load Zone, the Demand$

Congestion of a constraint is the product of the constraint shadow price, the Load Zone shift factor (SF) on that constraint, and the zonal load. For NYCA, the Demand$ Congestion is the sum of all of the zonal Demand$ Congestion.

These definitions are consistent with the reporting of historic congestion for the past thirteen 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 total payments by load since it does include the energy and losses components of the LBMP.

Principal Benefit Metric[11]

The principal benefit metric for the CARIS Study Phase analysis is the present value of the NYCA-wide production cost savings that are projected to result from implementation of each 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 consistent with the methodology utilized in the prior three CARIS cycles. Specifically, the NYCA-wide production cost savings are calculated using the following formula:

$$\text{NYCA-wide Production Cost Savings} = \text{NYCA Generator Production Cost Savings} - \sum \left\{ \left[\frac{\text{Import}}{\text{Export Flow}} \right]_{\text{Solution}} - \left[\frac{\text{Import}}{\text{Export Flow}} \right]_{\text{Base}} \right\} * \text{ProxyLMP}_{\text{Solution}}$$

Where:

$\text{ProxyLMP}_{\text{Solution}}$ is the LMP at one of the external proxy buses;

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

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 additional informational metrics to be defined for this CARIS cycle given

11 Section 31.3.1.3.4 of the Tariff specifies the principal benefit metric for the CARIS analysis.

existing resources and available data. The collaborative process determined the methodology and models needed to develop and implement these additional metrics requirements, which are described below and detailed in the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies 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.

Generator Payments – This metric measures the change in generation payments by measuring only the LBMP payments (energy, congestion, losses). Thus, total generator payments are calculated for this information metric as the sum of the LBMP payments to NYCA generators and payments for net 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 ICAP 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 captures 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 than it is calculated for Phase 2 of the CARIS process, as described in the NYISO Tariff. The TCC Payment is the change in total congestion rents collected in the day-ahead market. In this CARIS Phase 1, it is calculated as (Demand Congestion Costs + Export Congestion Costs) – (Supply Congestion Costs + Import Congestion Costs). This is not a measure of the Transmission Owners' TCC auction revenues.

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 2017 CARIS Phase 1 Study Period aligns with the ten-year reliability planning horizon for the 2016 CRP; and study assumptions are based on the 2016 CRP Base case and any updates that met the NYISO's inclusion rules as of the August 15, 2017 lock-down date.

The NYISO developed four distinct cases as baselines for the six ten-year studies performed. The first case can be viewed as a "business as usual" case (BAU case), incorporating incremental resource changes based on the NYISO's study inclusion rules. A second case is more forward-looking and captures impacts of global changes on the New York electric system that are exemplified by the achievement of New York's Clean Energy Standard through large-scale growth in renewable resources and implementation of energy-efficiency programs. This second case is referred to as the System Resource Shift (SRS) case, and these assumptions are discussed below in the "System Resource Shift" Model Assumptions section. The third and fourth baseline cases were limited variations on the BAU and SRS cases with the Edic-Marcy constraint relaxed.

Both the BAU and SRS assumptions were discussed with stakeholders at several meetings of the ESPWG and were used to project future system conditions. Appendix C includes a detailed description of the assumptions utilized in the CARIS analysis.

"Business as Usual" Case - System Assumptions & Modeling Changes

The key assumptions for the BAU case are presented below:

1. The load and capacity forecasts were updated using the 2017 Load and Capacity Data Report (Gold Book) baseline forecast for energy and peak demand by zone for the ten year Study Period. New resources and changes in resource capacity ratings were incorporated based on the RNA inclusion rules.

2. The 2016 CRP power flow base cases for the NYCA, ISO-NE and IESO were utilized without update in the 2017 CARIS study. The PJM power flow was developed from the 2017 PJM Regional Transmission Expansion Plan ("RTEP") case.

3. The transmission and constraint model utilizes a bulk power system representation for most of the Eastern Interconnection as described below. The model uses both the 2016 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 by the NYISO 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 each unit's planned and forced outage rates.

Figure 10 below contains a summary of the modeling changes that can have significant impacts on the congestion projections.

Figure 10: Major Modeling Inputs and Changes

Major Modeling Inputs	
Input Parameter	**Change from 2015 CARIS**
Load Forecast	Lower
Natural Gas Price Forecast	Lower
CO_2 Price Forecast	Lower
NO_X Price Forecast	Ozone NO_X, higher; Annual NO_X, lower
SO_2 Price Forecast	Lower
Hurdle Rates	PJM & IMO, lower; ISO-NE, higher
Modeling Changes	
Description	**Change from 2015 CARIS**
MAPS Software Upgrades	Latest GE MAPS Version 13.9 10/13/2016 Release was used for production cost simulation
PJM/NYISO JOA	Western tie to carry 32% of PJM-NYISO AC Interchange
	5018 line to carry 32% of PJM-NYISO AC Interchange plus 80% of RECO load
	PAR ABC to carry 21 % of PJM-NYISO AC Interchange plus 400MW OBF(operational base flow)
	OBF reduced to zero on May 31, 2021
	PAR JK to carry 15% of PJM-NYISO AC Interchange minus 400MW OBF
NY Transmission Upgrades	3rd Oakdale 345/115 kV transformer and reconfiguration of Oakdale 345 kV station (2021)
	Seasonal by-pass of Marcy South Series Compensation (MSSC)
	Terminal upgrade on Stolle-Gardenville 66 line
	Clay-Pannell 345 kV lines PC1 and PC2 terminal upgrades

Figure 11 presents the time-line of projected resource and topology changes that were modeled by the NYISO in each of the cases in accordance with the requirements of the Tariff and have material impacts on the simulation outcomes.

Figure 11: Timeline of NYCA Changes

Year	Year-to-Year Changes
2017	Greenidge Unit #4, 106.3 MW, in-service: 3/1/2017
	Freeport CT1 retired on 10/31/2017
	Ogdensburg , 79 MW,in-service: 11/1/2017
	Arkwright Summit Wind, 78 MW, in-service: 11/1/2017
2018	CPV Valley Plant, 677.6 MW, in-service: 2/1/2018
	Bayonne GT Uprate from 460 MW to 576 MW, 3/1/2018
	Taylor Biomass, 19 MW, in-service: 4/1/2018
	Copenhagen Wind, 79.9 MW, in-service: 5/1/2018
	Shoreham Solar, 25 MW, in-service: 6/1/2018
	Eight Point Wind Energy, 101.2 MW, 12/1/2018
2019	Cricket Valley Energy Center, 1,020 MW, in-service: 8/1/2019
	Cassadaga Wind, 126 MW, in-service: 12/1/2019
2020	
2021	
2022	
2023	
2024	Athens SPS retired on 6/2024
2025	
2026	

Load and Capacity Forecast

The load and capacity forecast used in the CARIS BAU case, provided in Figure 12, was based on the 2017 Gold Book and accounts for the impact of programs such as the Energy Efficiency Portfolio Standard (EEPS). Appendix C contains similar load and capacity data, broken out by fuel type, for the modeled external control areas.

Figure 12: CARIS 1 Base Case Load and Resource Table

Peak Load (MW)											
Area		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NYCA		33,178	33,078	33,035	32,993	33,009	33,034	33,096	33,152	33,232	33,324
Zone J		11,670	11,707	11,758	11,788	11,820	11,838	11,869	11,904	11,959	12,027
Zone K		5,427	5,305	5,229	5,174	5,172	5,177	5,198	5,206	5,226	5,238
Resources (MW)											
Area	Resource Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NYCA	Capacity	39,607	39,461	39,470	39,892	40,132	40,132	40,132	40,132	40,132	40,132
	SCR	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192
	Total	40,799	40,653	40,662	41,084	41,324	41,324	41,324	41,324	41,324	41,324
Zone J	Capacity	10,247	10,247	10,247	10,247	10,247	10,247	10,247	10,247	10,247	10,247
	SCR	372	372	372	372	372	372	372	372	372	372
	Total	10,619	10,619	10,619	10,619	10,619	10,619	10,619	10,619	10,619	10,619
Zone K	Capacity	6,083	6,083	6,083	6,083	6,083	6,083	6,083	6,083	6,083	6,083
	SCR	50	50	50	50	50	50	50	50	50	50
	Total	6,133	6,133	6,133	6,133	6,133	6,133	6,133	6,133	6,133	6,133

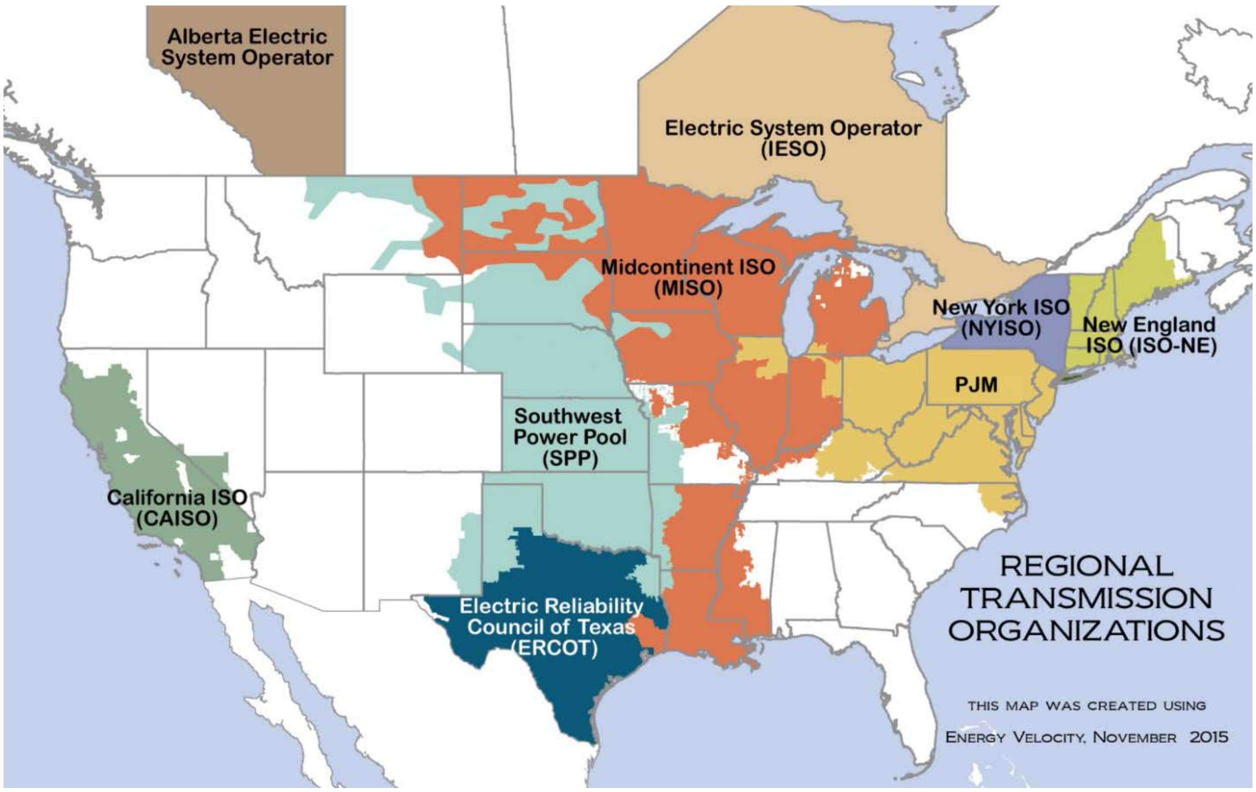
Source: 2017 Gold Book baseline load forecasts from Section I.[12]

12 NYCA "Capacity" values include resources internal to New York, additions, re-ratings, retirements, purchases and sales, and UDRs as presented in the 2017 Gold Book. Zones J and K capacity values include UDRs for the entire capacity of the controllable lines consistent with the 2016 RNA.

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 13 below illustrates the NERC Regions and Balancing Authorities in the CARIS model. The CARIS model includes a full active representation for the NYCA, ISO-NE, IESO, and PJM.

Figure 13: Areas Modeled in CARIS (Include NYISO, ISO-NE, IESO & PJM)



Source: FERC - https://www.ferc.gov/industries/electric/indus-act/rto/elec-ovr-rto-map.pdf

New York Control Area Transfer Limits

CARIS utilizes normal transfer criteria for MAPS simulations for production costing, but it adopts emergency transfer criteria for MARS simulations in order to estimate the projected changes in NYCA and locational reserve margins due to each of the modeled solutions for the purpose of calculating an ICAP metric. Normal thermal interface transfer limits for the CARIS study are not directly utilized from the thermal transfer analysis performed using the Power Technologies Inc. Managing and Utilizing System Transmission (MUST) or PowerGEM's Transmission Adequacy & Reliability Assessment (TARA) software application. Instead, CARIS uses the most limiting monitored lines and contingency sets identified from either MUST/TARA analysis or historical binding constraints.

For voltage and stability based limits the normal and emergency limits are assumed to be the same. For NYCA interface stability transfer limits, the limits are consistent with the operating limits.[13] Central East was modeled with a unit sensitive nomogram reflective of the algorithm utilized by NYISO Operations.[14]

Fuel Forecasts

CARIS Base Annual Forecast

The fuel price forecasts for CARIS are based on the U.S. Energy Information Administration's (EIA)[15] 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 nominal dollars. The same fuel forecast is utilized for all study cases and scenarios, except for the high and low natural gas price scenarios.

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. Key sources of data for estimating the relative differences or 'basis' for fuel-oil and coal prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on the information collected through Form EIA-923.[16] The regional bases for natural gas prices are based on a comparative analysis of monthly national delivered prices published in EIA's Short Term Energy Outlook (STEO) and spot prices for selected trading hubs. The base annual forecast series from the AEO are then subjected to an adjustment to reflect the New York 'basis' relative to the national delivered prices as described below.

Natural Gas

For the 2017 CARIS study, the New York Control Area is divided into four (4) gas-regions: Upstate (Zones A to E), Midstate (Zones F to I), Zone J, and Zone K.

Given that gas-fueled generators in a specific NYCA zone acquire their fuel from several gas-trading hubs, each regional gas price is estimated as a weighted blend of individual hubs – where the weights are the sub-totals of the generators' Summer Dependable Maximum Net Capacity (DMNC) MW levels. The regional natural gas price blends for the regions are as follows:

13 http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/operating_studies/NYISO_InterfaceLimtsandOperatingStudies.pdf

14 http://www.nyiso.com/public/webdocs/markets_operations/market_data/power_grid_info/CE_VC_Static_limit_posting.pdf

15 www.eia.doe.gov

16 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.

- Upstate (Zones A to E) – Dominion South (70%), Iroquois Waddington (20%), & Dawn (10%);
- Midstate (Zones F to I) – Iroquois Zone 2 (45%), Tennessee Zone 6 (30%), Tetco M3 (15%), & Algonquin Citygate (10%);
- Zone J – Transco Zone 6 (95%) & Tetco M3 (5%);
- Zone K – Iroquois Zone 2 (65%) & Transco Zone 6 (35%)

The forecasted regional 'basis' or the differential between the blended regional price and the national average, is calculated as the 3-year weighted-average of the ratio between the regional price and the national average delivered price from the STEO.[17] Forecasted fuel prices for the gas regions are shown in Figure 14 through Figure 17.

Fuel Oil

Based on EIA forecasts published in its Electric Power Projections by Electricity Market Module Regions (see AEO 2017, Reference Case), price differentials across regions can be explained by a combination of transportation/delivery charges and taxes. Regional bases were calculated based on the relative differences between EIA's national and regional forecasts of Distillate (Fuel Oil #2) and Residual (Fuel Oil #6) prices. This analysis suggests that for New York, Distillate and Residual Oil prices will be the same as the national average. For illustrative purposes, forecasted prices for Distillate Oil and for Residual Oil are shown in Figure 14 through Figure 17.

Coal

The data from EIA's Electric Power Projections by Electricity Market Module Regions was also used to arrive at the forecasted 'basis' for coal. Prices in New York are forecasted to be, on average, 28% 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.).

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.[18] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly

17 The raw hub-price is 'burdened' by an appropriate level of local taxes and approximate delivery charges. In light of the high price volatility observed during winter months, the 'basis' calculation excludes data for January, February and December.

18 This is a two-step process: First, deviations around a centered 12-month moving average were calculated over the 2012-2016 period; second, the average values of these deviations were normalized to estimate monthly/seasonal factors.

prices.

The 2017 data used to estimate the seasonal factors are as follows:

- Natural Gas: Raw daily prices from ICE (Intercontinental Exchange) for the various trading hubs incorporated in the regional price blends..
- Fuel Oil #2: EIA's average daily prices for New York Harbor Ultra-Low Sulfur No. 2 Diesel Spot Price. CARIS assumes the same seasonality for both types of fuel-oil.

The seasonalized time-series represents the forecasted trend of average monthly prices. Since CARIS uses weekly prices for its analysis, the monthly forecasted prices are interpolated to yield 52 weekly prices for a given year. Furthermore, "'spikes" are layered on these forecasted weekly prices to capture typical intra-month volatility, especially in the winter months. The "spikes" are calculated as 5-year averages of deviations of weekly (weighted-average) spot prices relative to their monthly averages. The "spikes" for a given month are normalized such that they add to zero.

Figure 14: Forecasted fuel prices for Zones A-E (nominal $)

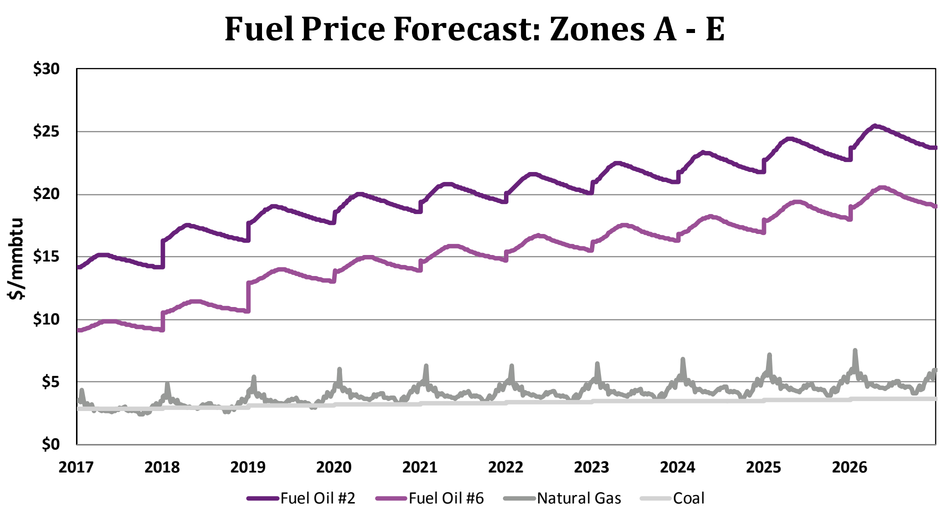


Figure 15: Forecasted fuel prices for Zones F-I (nominal $)

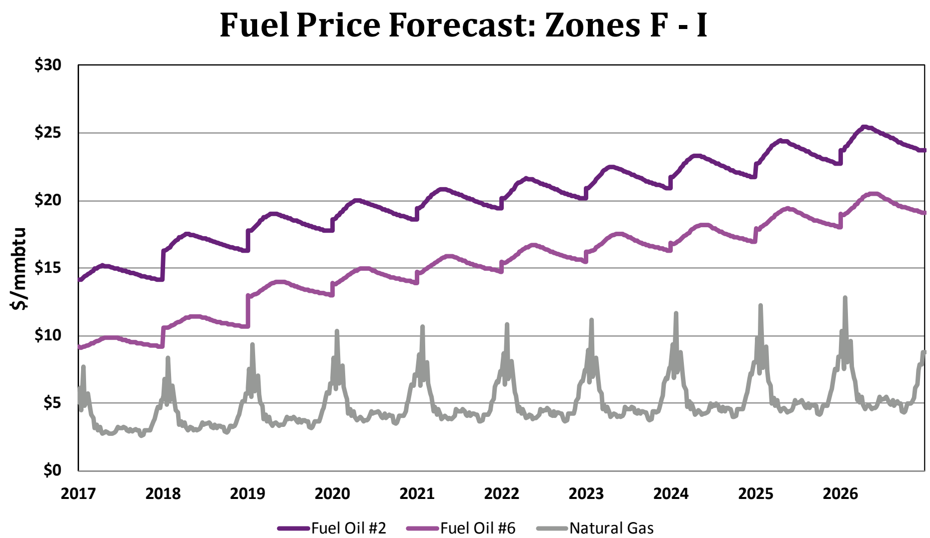


Figure 16: Forecasted fuel prices for Zone J (nominal $)

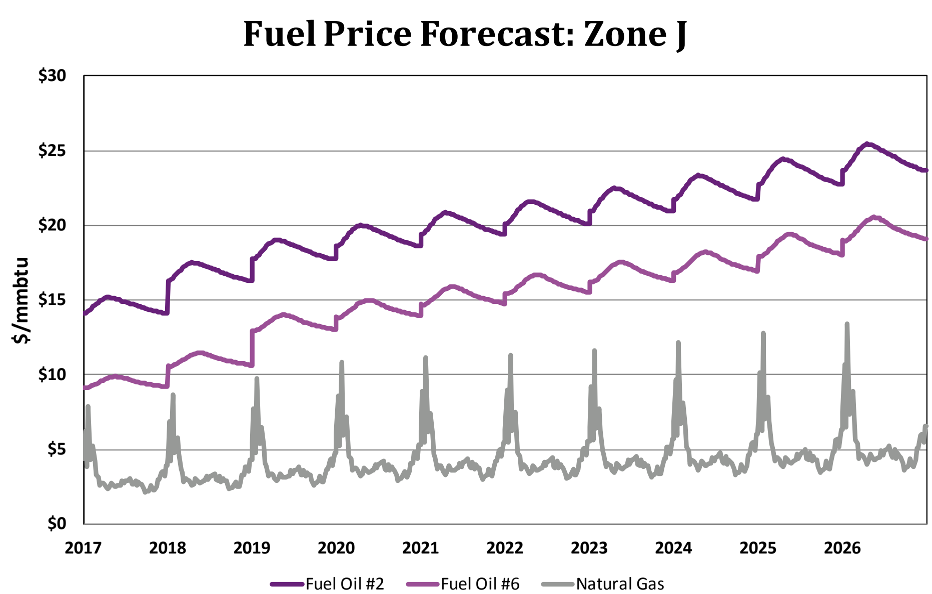
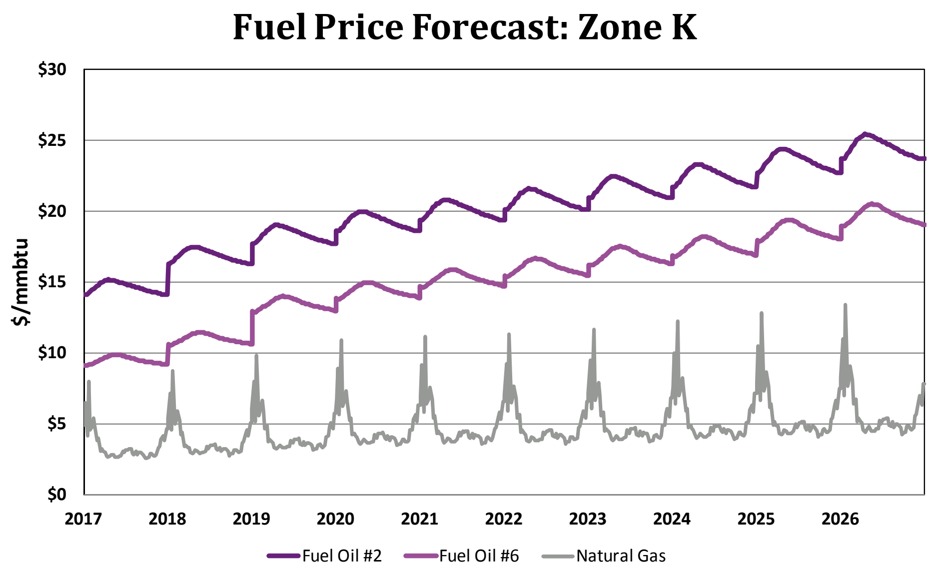


Figure 17: Forecasted fuel prices for Zone K (nominal $)



External Areas Fuel Forecast

The fuel forecasts for the three external Control Areas, ISO-NE, PJM and IESO, were also developed. For each of the fuels, the 'basis' for ISO-NE North, ISO-NE South, PJM-East and PJM-West were based on the EIA data obtained from the same sources as those used for New York. With respect to IESO, the relative price of Natural Gas is based on spot-market data for the Dawn hub obtained from a SNL. CARIS does not model any Ontario generation as being fueled by either oil or coal. External price forecasts are provided in Appendix C.

Emission Cost Forecast

The costs of emission allowances are an increasing portion of generator production costs. Currently, all NYCA fossil fuel-fired generators greater than 25 MW and most generators in many surrounding states are required to hold allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2.

Base Case allowance prices for annual and seasonal NO_X and SO_2 are developed using representative prices at the time the assumptions are finalized. The CSAPR NO_X and SO_2 allowances prices reflect the persistent oversupply of annual programs and the expectation that stricter seasonal limitations in the CSAPR Update will be manageable program-wide leading to price declines as market participants adjust to new operational limits.

USEPA's Mercury and Air Toxics Standard (MATS), requires reductions in mercury, acid gas, and particulate matter emissions. The standard became effective on April 16, 2015 (with the option for an additional year to comply available to most generators). Compliance with the acid gas reduction portion of the standard may be achieved through an alternate SO_2 emission limit. While the rule takes a command and control approach to lowering emissions, USEPA posits in the rulemaking that the majority of the decreases in acid gas emissions required by MATS will be accomplished by the CSAPR SO_2 cap and trade program. For these reasons, USEPA's CSAPR SO_2 price projections are augmented with a $1/MWh cost to cover the incremental operation of control equipment for MATS at coal units beginning in 2016.

The RGGI program for capping CO_2 emissions from power plants includes the six New England states as well as New York, Maryland, and Delaware. Historically the RGGI market has been oversupplied, and prices have remained near the floor. In January 2012 several states, including New York, chose to retire all unsold RGGI allowances from the 2009-2011 compliance period in an effort to reduce the market oversupply. Additionally, RGGI Inc. conducted a mid program review in 2012 which, then became effective in 2014. The emissions cap was reduced to 91 million tons in 2014 and will decrease to 78 million tons in 2020.

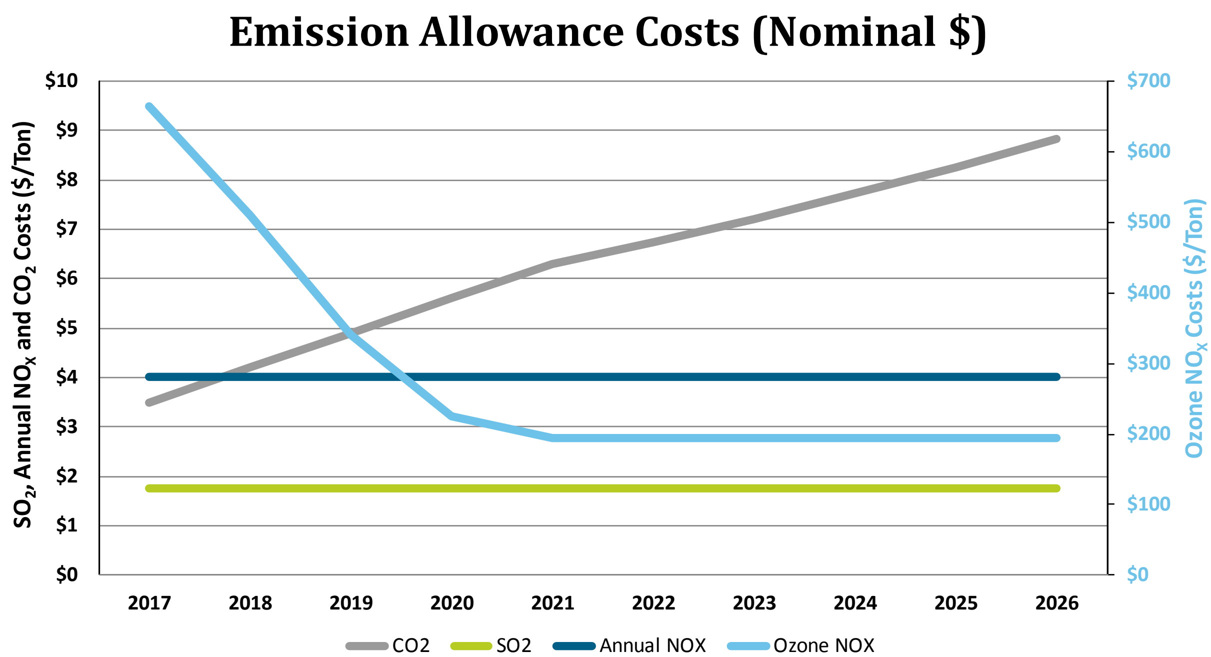
Following the cap reduction, the emissions cap became binding on the market triggering the Cost Containment Reserve (CCR). In 2014, five million additional allowances were sold at auction followed by an additional ten million CCR allowances in 2015. In February 2016, the Supreme Court stayed implementation of the USEPA Clean Power Plan. The market response to this ruling was a reduction in RGGI OTC prices which have not fully recovered since. RGGI also undertook another program review in 2016-2017 proposing additional changes to the program structure, including a 30% cap reduction between 2020 and 2030. An Emission Containment Reserve (ECR) was added to provide price support by holding back allowances from auction if prices do not exceed predefined threshold levels.

The allowance price forecast assumes auctions will clear in line with the ECR trigger price through the study period. The past CARIS Study assumed that a federal CO_2 program, similar to the RGGI program, would take effect in 2020, however the expectation of such a program have since dampened and currently no national program is assumed within the study period. The study assumes a distinct CO_2 allowance price forecast applicable to Ontario generation based upon provincial estimates.

Figure 18 shows the emission allowance forecast by year in $/Ton.[19]

19 Annual NO_X prices are used October through May; Ozone NO_X prices May through September.

Figure 18: Emission Allowance Forecast



Recent announcements from newly elected administrations in Virginia and New Jersey have stated their intentions to either join the RGGI states in the use of CO_2 emission allowances or develop similar cap and trade systems. When the stated intentions are developed into promulgated rules, it will be timely to include the cost of CO_2 emission allowances in the production models for these states that reflect the final versions of the systems adopted.

Generic Solutions

Generic solutions are evaluated by NYISO for each of the CARIS studies utilizing each resource type (generation, transmission, energy efficiency (EE) and demand response (DR)) as required in Section 31.3.1.3.3 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 only are intended to set forth an order of magnitude of the potential projects' 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 or in the locations assumed.

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 Figure 19 through Figure 21.

Figure 19: Transmission Block Sizes[20]

Location	Line System Voltage (kV)	Normal Rating (MVA)
Zone E-G	345	1,986

Figure 20: Generation Block Sizes[21]

Plant Location	Plant Block Size Capacity (MW)
Zone F-G	340

Figure 21: EE and DR Block Sizes

Location	Resource Quantity (MW)	Portfolio Type
Zone F-J	200	Energy Efficiency
Zone F-J	200	Demand Response

Guidelines and Assumptions for Generic Solutions

Developing cost estimates for these resource types was dependent on many different parameters and assumptions and without consideration of project feasibility or project-specific costs.

The following guidelines and assumptions were 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

20 Solution size is based on a double-bundled ACSR 1590 KCmil conductor rated for 3,324 amps.

21 Proposed generic unit is a Siemens SGT6-5000F(5).

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. Space availability at substations (i.e., room for substation expansion) was not evaluated in this process.

Generation Resource

- The generic generation solution consisted 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 was selected. Space availability at substations (i.e., room for substation expansion) was not evaluated in this process.
- The total resource increase in megawatts should be comparable to the megawatt increase in transfer capability due to transmission solution.

Energy Efficiency (EE)

- 200 MW blocks of peak load energy efficiency.
- Aggregated at the downstream of the congested elements.
- Limited to whole blocks that total less than 10% of the zonal peak load. If one zone reaches a limit, EE may be added to other downstream zones.
- The total resource increase in megawatts should be comparable to the megawatt increase in transfer capability due to transmission solution.

Demand Response (DR)

- 200 MW demand response modeled at 100 peak hours.
- Use the same block sizes in the same locations as energy efficiency.

Generic Solution Pricing Considerations

Three sets of cost estimates which were designed to be reflective of the differences in labor, land and permitting costs among Upstate, Downstate and Long Island follow below. The considerations used for estimating costs for the three resource types and for each geographical area are listed in Figure 22.

Figure 22: Generic Solution Pricing Considerations

Transmission	Generation	Energy Efficiency	Demand Response
Transmission Line Cost per Mile	Equipment	Energy Efficiency Programs	Demand Response Programs
Substation Terminal Costs	Construction Labor & Materials	Customer Implementation Costs	Customer Implementation Costs
System Upgrade Facilities	Electrical Connection & Substation		
	Electrical System Upgrades		
	Gas Interconnect & Reinforcement		
	Engineering & Design		

Low, mid, and high cost estimates for each element were provided to stakeholders for comment. The transmission cost estimates were reviewed by Market Participants, including Transmission Owners; and the estimated cost data for the mid-point of the generation solutions were taken from the 2016 Demand Curve Reset report. The low and high-point of the generic cost estimates for Energy Efficiency were derived from a study produced on behalf of the New York State Department of Public Service by Industrial Economics and Optimal Energy.[22] Finally, the mid-point of the Demand Response costs was extracted from most recent New York Public Service Commission filings by utilities on Commercial System Relief Program (CSRP) costs and enrollments. This establishes a range of cost estimates to address the variability of generic projects. The resulting order of magnitude unit pricing levels are included below in the "Cost Analysis" section below. A more detailed discussion of the cost assumptions and calculations is included in Appendix E.

22 *Final Generic Environmental Impact Statement In CASE 14-M-0101 - Reforming the Energy Vision and CASE 14-M-0094 - Clean Energy Fund*, New York State Department of Public Service, February 6, 2015, page 4-7.

"System Resource Shift" Model Assumptions

As noted in the prior section, the NYISO developed a second baseline case as a means of studying the impact of more extensive resource changes on NYCA congestion patterns. This case is largely built on the 'Business as Usual" case with limited but impactful differences:

- Retirement of all New York coal units, consistent with Governor Cuomo's 2016 pledge[23].
- Retirement of Indian Point Energy Center, consistent with the completed deactivation notice[24].
- Integration of sufficient renewable energy and energy efficiency consistent with the objectives of the Clean Energy Standard.[25]

These resource changes are captured in the following figures. In addition approximately 10.5 TWh of energy efficiency was modeled. All other assumptions, including the fuel price and emission allowance costs, are identical in both the "Business as Usual" and "System Resource Shift" cases. With these assumptions, approximately 49% of New York's energy requirements were projected to be served by renewable sources, nearly reaching the "50 by 30" value in 2026, the final year of this study. One additional implication of the SRS Case is a decrease in net imports from PJM, IESO and ISO-NE (from the BAU) case by 14 TWh.

Figure 23: Timeline of NYCA changes in System Resource Shift Case from Base Case

Year	Year-to-Year Changes
2017	
2018	
2019	Somerset and Cayuga 1&2 retired on 12/31/2019
2020	Indian Point 2 retired on 04/01/2020
2021	Indian Point 3 retired on 04/01/2021
2022	
2023	
2024	
2025	
2026	

23 https://www.governor.ny.gov/sites/governor.ny.gov/files/atoms/files/2016_State_of_the_State_Book.pdf

24http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planned_Generation_Retirements/Planned_Retirement_Notices/Posting-of-Completed-Generator-Deactivation-Notice-Indian-Point%20Units-2-and-3-11-13-17.pdf

25 New York State Department of Public Service, *Staff White Paper on Clean Energy Standard (CASE 15-E-0302)*, January 25, 2016. For purposes of this study, the NYISO compressed the assumed implementation schedule and limited the build-out of renewable resources to wind and solar in addition to energy-efficiency -- the CES had also included increases in hydro and biomass resources -- to achieve the renewable production levels consistent with the CES's goal of "50 by 30" by 2026.

Figure 24: Capacity of Zonal Renewable Generation added in SRS Case (MW)

Zone	Resource	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Total	Land-Based Wind		89	541	463	498	360	345	854	784	630	4,565
	Utility-Scale Solar				605	746	1,082	1,088	1,804	2,031	3,479	10,837
	Offshore Wind									248		248
	Imports						229	229				458
Zone A	Land-Based Wind		89	445	364	66	278	95		212	93	1,642
	Utility-Scale Solar							894		663	718	2,275
	Offshore Wind											
Zone B	Land-Based Wind											
	Utility-Scale Solar										307	307
	Offshore Wind											
Zone C	Land-Based Wind									222		222
	Utility-Scale Solar						1,082				2,322	3,404
	Offshore Wind											
Zone D	Land-Based Wind											
	Utility-Scale Solar										132	132
	Offshore Wind											
Zone E	Land-Based Wind					175		137	537	264	470	1,584
	Utility-Scale Solar											
	Offshore Wind											
Zone F	Land-Based Wind			55	65	185	82	80	240	41	67	815
	Utility-Scale Solar				605	502			1,804	248		3,159
	Offshore Wind											
Zone G	Land-Based Wind			41	34	72		32		46		225
	Utility-Scale Solar					127		195		611		933
	Offshore Wind											
Zone H	Land-Based Wind											
	Utility-Scale Solar					11						11
	Offshore Wind											
Zone I	Land-Based Wind											
	Utility-Scale Solar											
	Offshore Wind											
Zone J	Land-Based Wind											
	Utility-Scale Solar											
	Offshore Wind											
Zone K	Land-Based Wind								77			77
	Utility-Scale Solar					106				509		616
	Offshore Wind									248		248
Imports	Land-Based Wind Quebec											
	Ontario Utility Scale Solar											
	Land-Based Wind Ontario						229	229				458
	Land-Based Wind PJM											
	PJM Utility Scale Solar											
Total		0	89	541	1,068	1,244	1,671	1,662	2,659	3,064	4,109	16,108

Figure 25: CARIS 1 SRS Case Load and Resource Table

Peak Load (MW)											
Area		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NYCA		33,023	32,793	32,620	32,429	32,299	32,194	32,126	32,039	31,975	31,881
Zone J		11,592	11,604	11,640	11,640	11,647	11,654	11,673	11,697	11,737	11,781
Zone K		5,409	5,258	5,152	5,061	5,021	4,992	4,979	4,951	4,934	4,894
Resources (MW)											
Area	Resource Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NYCA	Capacity	39,607	39,550	39,187	39,678	40,121	41,562	42,996	45,654	48,718	52,827
	SCR	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192
	Total	40,799	40,742	40,379	40,870	41,313	42,754	44,188	46,846	49,910	54,019
Zone J	Capacity	10,247	10,247	10,247	10,247	10,247	10,247	10,247	10,247	10,247	10,247
	SCR	372	372	372	372	372	372	372	372	372	372
	Total	10,619	10,619	10,619	10,619	10,619	10,619	10,619	10,619	10,619	10,619
Zone K	Capacity	6,083	6,083	6,083	6,083	6,190	6,190	6,190	6,267	7,024	7,024
	SCR	50	50	50	50	50	50	50	50	50	50
	Total	6,133	6,133	6,133	6,133	6,240	6,240	6,240	6,317	7,074	7,074

Source: 2017 Gold Book values adjusted to reflect System Resource Shift case

2017 CARIS Phase 1 Results

This section presents summary level results of the six steps of the 2017 CARIS Phase 1. These six steps include: (1) congestion assessment; (2) ranking of congested elements; (3) selection of studies; (4) generic solution applications; (5) benefit/cost analysis; and (6) scenario analysis. Study results are described in more detail in Appendix E.

Congestion Assessment

The CARIS process begins with the development of a ten-year projection of future Demand$ 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. 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 that prevent lower cost resources from being delivered towards the Marcy bus.

Historic Congestion

Historic congestion assessments have been conducted at the NYISO since 2005 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. For more information on the historical results below see:

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

Historic congestion costs by zone, expressed as Demand$ Congestion, are presented in Figure 26, indicating that the highest congestion is in New York City and Long Island.

Figure 26: Historic Demand$ Congestion by Zone 2012-2016 (nominal $M)[26]

Zone	2012	2013	2014	2015	2016
West	$6	$45	$36	$83	$116
Genesee	$3	$11	$9	$9	$7
Central	$8	$38	$38	$34	$29
North	$0	$5	$3	$5	$7
Mohawk Valley	$3	$11	$12	$10	$7
Capital	$34	$143	$149	$123	$95
Hudson Valley	$39	$112	$95	$86	$64
Millwood	$10	$30	$30	$26	$19
Dunwoodie	$24	$62	$55	$49	$41
New York City	$261	$639	$531	$459	$378
Long Island	$377	$597	$409	$404	$339
NYCA Total	**$765**	**$1,693**	**$1,367**	**$1,287**	**$1,102**

Figure 27 below lists historic congestion costs, expressed as Demand$ Congestion, for the top NYCA constraints from 2012 to 2016. The top congested paths are shown below.

Figure 27: Historic Demand$ Congestion by Constrained Paths 2012-2016 (nominal $M)

Constraint Path	2012	2013	2014	2015	2016	Total
CENTRAL EAST	$255	$1,089	$1,136	$915	$641	$4,036
DUNWOODIE TO LONG ISLAND	$266	$307	$155	$138	$164	$1,029
LEEDS PLEASANT VALLEY	$137	$138	$42	$111	$63	$492
GREENWOOD	$72	$96	$13	$19	$31	$232
NIAGARA PACKARD	$3	$21	$18	$22	$44	$108
PACKARD HUNTLEY	$0	$5	$7	$41	$54	$107
NEW SCOTLAND LEEDS	$9	$27	$9	$32	$13	$90
DUNWOODIE MOTTHAVEN	$22	$18	$40	$2	$2	$84
SHORE_RD 345 SHORE_RD 138 1	$4	$36	$12	$27	$2	$81

* Ranking is based on absolute values.

Figure 28 summarizes the annual historic congestion results posted by the NYISO. NYISO reports the summaries of the calculated changes in the four historic congestion metrics: Bid Production Cost (BPC), Generator Payments, Congestion Payments, and Load Payments. The changes in these four historic congestion metrics were calculated using CROS 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 (TCC auction proceeds). 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

26 Reported values do not deduct TCCs. NYCA totals represent the sum of absolute values. DAM data include Virtual Bidding and Planned Transmission Outages.

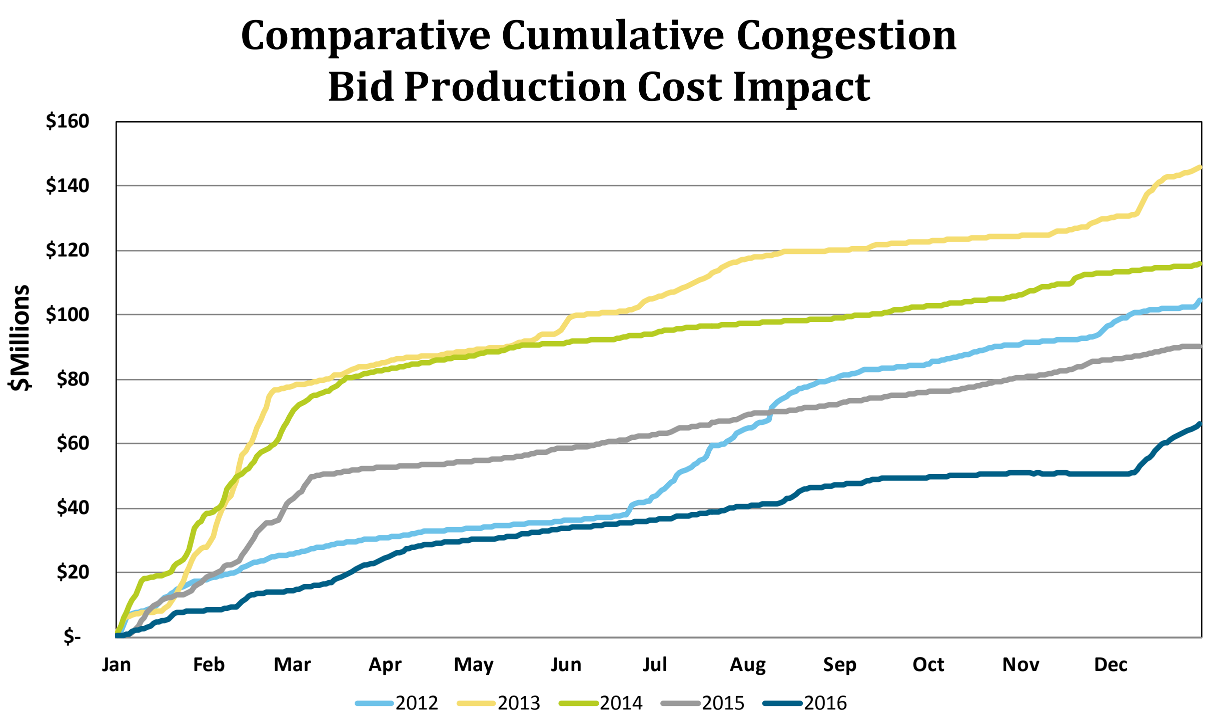
Payments.

Figure 28: Historic NYCA System Changes – Mitigated Bids 2012-2016 (nominal $M)

Historic NYCA System Changes - Mitigated Bids 2012 - 2016 (nominal $M)				
Year	Change in BPC	Change in Generator Payments	Change in Unhedged Congestion Payments	Change in TCC Payments
2012	$106	($55)	$457	$319
2013	$146	($186)	$1,066	$737
2014	$116	($435)	$847	$645
2015	$90	($235)	$803	$577
2016	$66	($125)	$572	$531

Figure 29 below illustrates a cumulative effect of bid production costs savings over the past five years as a result of relieving all NYCA constraints.

Figure 29: Historic Cumulative BPC Savings, 2012-2016 (nominal $M)



Projected Future Congestion

Future congestion for the Study Period was determined from a MAPS simulation using a base case developed with the ESPWG. As reported in the "Historic Congestion" section above, congestion is reported as Demand$ Congestion. MAPS simulations are highly dependent upon many long-term assumptions, each of which affects the study results. 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 CROS and MAPS. MAPS, unlike CROS, did not simulate the following: (a) virtual bidding; (b) transmission outages; (c) price-capped load; (d) generation and demand bid price; (e) Bid Production Cost Guarantee (BPCG) payments; and (f) co-optimization with ancillary services. As in prior CARIS cycles, the projected congestion is below historic levels due to the factors cited. Such factors could also lead to lower projections of production cost savings attributable to new infrastructure (e.g., transmission, generation, energy efficiency, demand response) constructed to address system congestion.

Discussion

Figure 30 presents the projected congestion from 2017 through 2026 by Load 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 the "Baseline System Assumptions" section above.

Figure 30: Projection of Future Demand$ Congestion 2017-2026 by Zone for Base Case (nominal $M)

Demand Congestion ($M)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
West	$58	$84	$77	$69	$53	$41	$49	$45	$51	$50
Genesee	$25	$30	$30	$27	$19	$18	$15	$18	$14	$15
Central	$31	$38	$39	$38	$28	$26	$28	$28	$28	$27
North	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Mohawk Valley	$1	$2	$2	$2	$3	$3	$2	$2	$2	$2
Capital	$40	$59	$77	$81	$88	$73	$44	$64	$52	$54
Hudson Valley	$44	$58	$69	$71	$69	$59	$41	$54	$45	$46
Millwood	$12	$17	$20	$20	$20	$17	$12	$16	$13	$13
Dunwoodie	$28	$36	$43	$44	$42	$36	$26	$34	$28	$29
NY City	$251	$354	$419	$421	$424	$372	$277	$352	$308	$322
Long Island	$146	$173	$212	$227	$232	$212	$181	$208	$195	$203
NYCA Total	**$636**	**$851**	**$990**	**$999**	**$979**	**$859**	**$674**	**$822**	**$735**	**$762**

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 Figure 31 below.

Figure 31: Projection of Future Demand$ Congestion 2017-2026 by Constrained Path for Base Case (nominal $M)

Demand Congestion ($M)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CENTRAL EAST	$115	$210	$311	$335	$398	$315	$167	$269	$205	$215
DUNWOODIE TO LONG ISLAND	$25	$21	$31	$37	$43	$45	$49	$47	$52	$53
LEEDS PLEASANT VALLEY	$2	$2	$3	$2	$3	$1	$0	$1	$4	$4
GREENWOOD	$12	$28	$27	$23	$25	$21	$22	$24	$27	$30
PACKARD HUNTLEY	$35	$20	$29	$34	$26	$32	$18	$28	$14	$17
EGRDNCTY 138 VALLYSTR 138 1	$9	$11	$13	$16	$18	$18	$19	$20	$19	$24
NIAGARA PACKARD	$4	$1	$2	$3	$3	$4	$1	$4	$2	$1
EDIC MARCY	$28	$8	$7	$7	$3	$5	$0	$3	$0	$1
DUNWOODIE MOTTHAVEN	$0	$0	$1	$0	$1	$1	$1	$2	$2	$2
NEW SCOTLAND LEEDS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Ranking of Congested Elements

The identified congested elements from the ten-year projection of congestion are appended to 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.

Figure 32 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, Dunwoodie-Long Island, and Leeds-Pleasant Valley continue to be the paths with the greatest projected congestion. The top elements are evaluated in the next step for selection of the three study cases.

Figure 32: Ranked Elements Based on the Highest Present Value of Demand$ Congestion over the 15 Yr Aggregate (Base Case)[27]

Present Value of Demand$ Congestion ($2017M)			
Element	Hist. Total	Proj. Total	15Y Total
CENTRAL EAST	$5,077	$1,966	$7,043
DUNWOODIE TO LONG ISLAND	$1,342	$298	$1,639
LEEDS PLEASANT VALLEY	$641	$17	$659
GREENWOOD	$309	$182	$491
PACKARD HUNTLEY	$124	$203	$327
EGRDNCTY 138 VALLYSTR 138 1	$85	$123	$208
NIAGARA PACKARD	$130	$20	$149
DUNWOODIE MOTTHAVEN	$112	$8	$119
NEW SCOTLAND LEEDS	$113	$0	$113
SHORE_RD 345 SHORE_RD 138 1	$104	$0	$104
EDIC MARCY	$45	$57	$102
RAINEY VERNON	$75	$7	$83

[27] The absolute value of congestion is reported.

The frequency of actual and projected congestion is shown in Figure 33 below. The figure presents the actual number of congested hours by constraint, from 2012 through 2016, and projected hours of congestion, from 2017 through 2026. The change in the number of projected hours of congestion, by constraint after each generic solution is applied, is shown in Appendix E.

Figure 33: Number of Congested Hours by Constraint (Base Case)

# of DAM Congested Hours	Actual					CARIS Base Case Projected									
Constraint	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CENTRAL EAST	1,471	3,374	3,022	4,091	4,636	978	1,176	1,657	1,988	2,012	1,692	960	1,511	1,055	1,194
DUNWOODIE TO LONG ISLAND	4,777	6,031	5,583	7,738	6,085	4,395	4,457	4,709	4,727	5,060	5,097	4,974	5,343	5,102	5,361
LEEDS PLEASANT VALLEY	392	624	384	965	623	26	19	21	9	14	9	4	19	16	11
GREENWOOD	2,983	3,415	1,438	7,456	7,347	8,593	8,566	8,621	8,654	8,671	8,747	8,733	8,766	8,727	8,725
PACKARD HUNTLEY	0	0	308	1,720	1,425	847	532	719	889	752	892	532	642	403	439
EGRDNCTY 138 VALLYSTR 138 1	2,934	5,908	5,142	3,191	3,479	6,810	7,147	7,242	7,355	7,631	7,738	7,798	7,730	7,700	7,750
NIAGARA PACKARD	N/A	N/A	N/A	756	1,279	141	32	65	119	106	133	34	100	37	41
DUNWOODIE MOTTHAVEN	644	504	190	231	134	6	23	25	11	54	49	50	57	58	66
EDIC MARCY	N/A	N/A	N/A	11	164	28	37	37	39	23	32	1	42	8	14
RAINEY VERNON	2,166	2,166	641	2,073	2,438	1,661	2,956	3,990	4,591	4,884	5,084	5,070	5,342	5,146	5,418
MOTTHAVEN RAINEY	N/A	N/A	N/A	80	188	7	18	65	179	503	740	604	689	667	743
STOLLE GARDENVILLE	N/A	N/A	N/A	318	429	163	101	199	91	110	144	89	86	101	57
E179THST HELLGT ASTORIAE	2,432	2,182	990	1,672	1,864	7,144	6,832	6,821	6,921	7,455	7,775	7,663	7,562	7,667	7,505
NEW SCOTLAND LEEDS	69	264	173	556	214	0	0	0	0	0	0	0	0	0	0
SHORE_RD 345 SHORE_RD 138 1	N/A	N/A	N/A	505	172	0	0	0	0	0	0	0	0	0	0

Identifying the CARIS Studies

Selection of the Studies

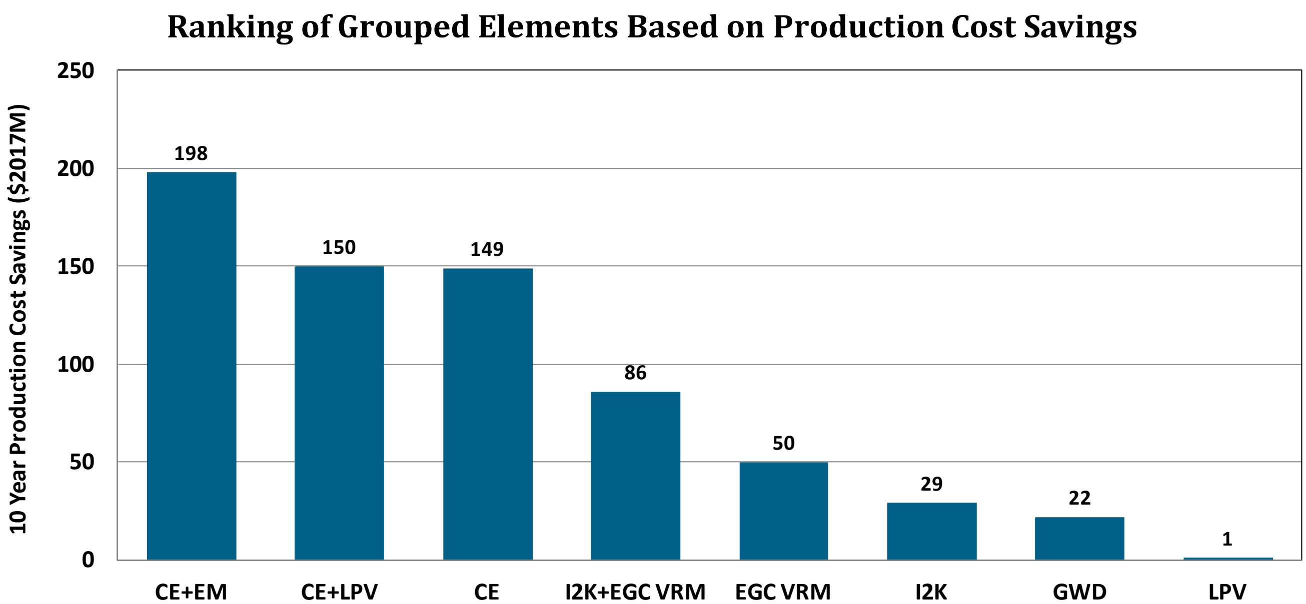
Selection of the CARIS studies is a two-step process in which the top ranked constraints are identified and utilized for further assessment in order to identify potential for grouping of constraints.[28] The resultant grouping of elements for each of the top ranked constraints is utilized to determine the CARIS studies. For the purpose of this selection exercise, the "Business as Usual" baseline case, as described above in the "Business as Usual-Modeling Assumptions" section, was utilized.

In Step 1, the top five congested elements for the fifteen-year period (both historic (5 years) and projected (10 years)) are ranked in descending order based on the calculated present value of Demand$ Congestion for further assessment.

In Step 2, the top congested elements from Step 1 are relieved independently by relaxing their limits. This is to determine if any of the congested elements need to be grouped with other elements, depending on whether new elements appear as limiting with significant congestion when a primary element is relieved. See Appendix E for a more detailed discussion. The assessed element groupings are then ranked based upon the highest change in production cost, as presented in Figure 34.

[28] Additional detail on the selection of the CARIS studies is provided in Appendix E.

Figure 34: Ranking of Grouped Elements Based on Production Cost Savings ($2017M)



Per the NYISO Tariff, the three ranked groupings with the largest change in production cost are then selected as the set of CARIS studies. For the 2017 CARIS Phase 1, these are Central East-Edic-Marcy (CE+EM), Central East-New Scotland-Pleasant Valley (CE-NS-PV), and Central East (CE). Unlike prior CARIS analyses, additional studies beyond these three were undertaken in the 2017 CARIS Phase 1 to provide stakeholders with supplemental and, arguably, more relevant data on system congestion and the impact of solutions to address that congestion. In these additional studies the base case assumptions were modified in order to study futures which did not at this time meet study inclusion rules but which merit analysis. Specifically, the Central East-New Scotland-Pleasant Valley (CE-NS-PV) study was adjusted to reflect (1) the relaxation of the Edic-Marcy constraint; (2) an alternate set of resource and load conditions (i.e., the System Resource Shift case) described above in the "System Resource Shift-Modeling Assumptions" section; and (3) the System Resource Shift case with the Edic-Marcy constraint relaxed as in the first alternate study case. Figure 35 and Figure 36 present the base case congestion associated with each of the six studies in nominal and real terms.

Figure 35: Demand$ Congestion for the Six CARIS Studies (nominal $M)

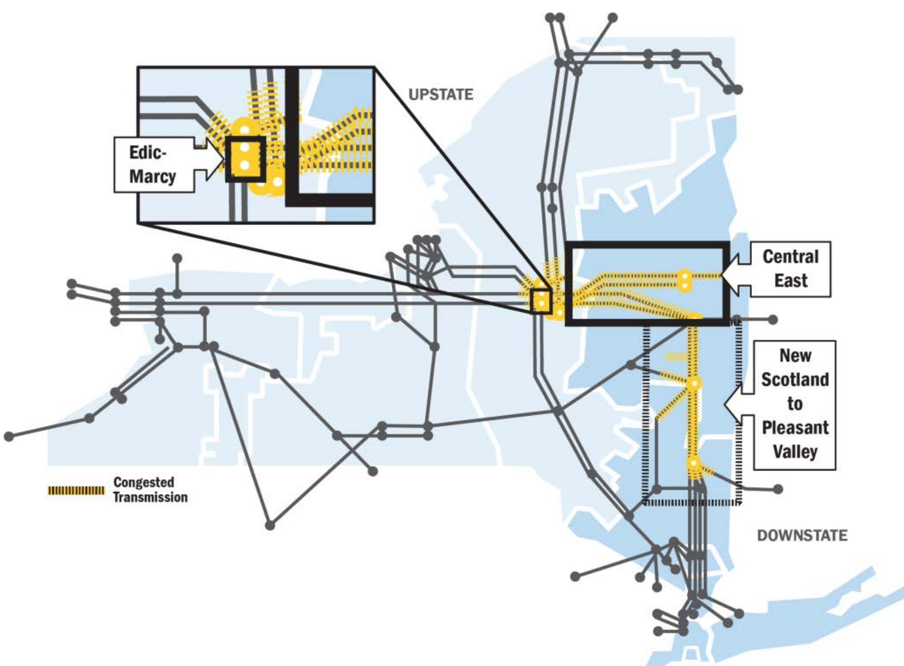
Study	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Study 1: Central East-Edic-Marcy	143	218	318	342	401	319	167	272	205	216
Study 2: Central East	115	210	311	335	398	315	167	269	205	215
Study 3: Central East-New Scotland-Pleasant Valley	118	212	313	337	401	316	168	270	208	219
Study 4: Study 3 with Edic-Marcy relaxed	168	250	399	436	503	415	255	364	274	307
Study 5: Study 3 under System Resource Shift Case	114	219	409	449	508	496	335	587	588	1,020
Study 6: Study 5 with Edic-Marcy relaxed	167	278	508	554	604	640	458	723	663	1,121

Figure 36: Demand$ Congestion for the Six CARIS Studies ($2017M)

Study	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Study 1: Central East-Edic-Marcy	148	211	287	289	316	236	115	176	123	122
Study 2: Central East	119	203	281	283	314	232	115	174	123	121
Study 3: Central East-New Scotland-Pleasant Valley	122	205	283	285	316	233	116	174	125	124
Study 4: Study 3 with Edic-Marcy relaxed	174	242	361	369	397	306	176	235	165	173
Study 5: Study 3 under System Resource Shift Case	118	211	370	379	401	366	231	378	354	574
Study 6: Study 5 with Edic-Marcy relaxed	173	269	459	468	477	472	316	466	399	631

The location of the top three congested groupings, along with the present value of congestion (in 2017 dollars) for the six studies, is presented in Figure 37.

Figure 37: Base Case Congestion of Top 3 Congested Groupings, 2017-2026 ($2017M)



Study 1: Central East-Edic-Marcy
Demand$ Congestion: 2,023 ($2017M)

Study 4: Study 3 with Edic-Marcy relaxed
Demand$ Congestion: 2,596 ($2017M)

Study 2: Central East
Demand$ Congestion: 1,966 ($2017M)

Study 5: Study 3 under System Resource Shift Case
Demand$ Congestion: 3,384 ($2017M)

Study 3: Central East-New Scotland-Pleasant Valley
Demand$ Congestion: 1,983 ($2017M)

Study 6: Study 5 with Edic-Marcy relaxed
Demand$ Congestion: 4,130 ($2017M)

Generic Solutions to Congestion

For each of the six studies, demand congestion is mitigated by individually applying one of the generic resource types; transmission, generation, energy efficiency 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 E and is consistent with the methodology explained earlier in 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 studied.
- Generic solutions are not assessed for impacts on system reliability or feasibility.
- 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 of 6.99% used for the present values analysis is the weighted average of the after-tax Weighted Average Cost of Capital (WACC) for the New York Transmission Owners. The weighted average is based on the utilities' annual GWh energy consumption for 2016.

Figure 39, Figure 42, Figure 45, Figure 48, Figure 51 and Figure 54 present the impact of each of the solutions on Demand$ Congestion for each of the studies in 2017$. Transmission has the greatest impact on reducing Demand$ Congestion (51% to 61%) because adding a transmission solution addresses the underlying system constraint that was driving the congestion. The generation solution had negligible impact on Demand$ Congestion (<1%) as the generic unit did not displace significant generation in the relevant base case. This is attributable in Studies 1-4 to a resource-rich environment downstream of the constraints, including Indian Point Energy Center, the Bayonne expansion, and the new, efficient Cricket Valley and CPV Valley combined-cycle facilities; and in Studies 5-6 to low forecasted loads and high penetration of cheaper renewable resources. The demand response solution had nearly no impact on Demand$ Congestion since this solution is essentially a limited summer season resource and, as such, is not operational during the winter hours in which Central East is most heavily congested. The energy efficiency solution, reducing load across the full year, reduced Demand$ Congestion by 9% to 13%.

Figure 40, Figure 43, Figure 46, Figure 49, Figure 52 and Figure 55 present the impact of each of the solutions on production costs for each of the studies in 2017$. Transmission had higher impacts than the generation solutions in all six studies. The impact of the Transmission solution on production costs ranges from $124M - $319M. The generation solution reduced production costs by $84M - $211M. The demand response solution resulted in the least production cost savings ($27M - $56M), again, as expected, since this solution impacted only the top 100 load hours. The energy efficiency solution shows the largest production cost savings (by $845M - $1.7B) because it directly reduces the energy production requirements.

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-Edic-Marcy (Base Conditions)

The following generic solutions were applied for Central East-Edic-Marcy Study under base conditions:

- Transmission: A new 345 kV line from Marcy to New Scotland, 85 Miles. The new line increases the Central East voltage transfer limit by about 580 MW. Cost estimates are: $324M (low); $463M (mid); and $602M (high).
- Generation: A new 680 MW Plant at New Scotland. Cost estimates are: $894 (low); $1,177M (mid); and $1,482M (high).
- Demand Response: 200 MW Demand Response in Zone F; 200 MW in Zone G; 200 MW in Zone J. Cost estimates are $240M (low); $320M (mid); and $400M (high).
- Energy Efficiency: 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 200 MW in Zone J. Cost estimates are $1,100M (low); $1,210M (mid); and $1,320M (high).

Figure 38 shows the Demand$ Congestion of Central East-Edic-Marcy for 2021 and 2026 before and after each of the generic solutions is applied. The Base Case congestion numbers, $401M for 2021 and $216M for 2026, are taken directly from Figure 35 representing the level of congestion of the Study 1 before the solutions.

Figure 38: Demand$ Congestion Comparison for Study 1 (nominal $M)

Study 1: Central East-Edic-Marcy						
Resource Type	2021			2026		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	401	161	(60%)	216	93	(57%)
Generation-680MW	401	403	0%	216	204	(6%)
Demand Response-600MW	401	401	0%	216	215	(0%)
Energy Efficiency-600MW	401	361	(10%)	216	209	(3%)

Figure 39 shows the Demand$ Congestion reduction for the 10-year Study Period in 2017 dollars from 2017 to 2026 for the Central East-Edic-Marcy study after generic solutions were applied.

Figure 39: Demand$ Congestion Comparison for Study 1 ($2017M)

Study 1: Central East-Edic-Marcy												
Resource Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	%Change
Transmission	(97)	(139)	(167)	(186)	(189)	(138)	(64)	(106)	(77)	(69)	(1,233)	(61%)
Generation-680MW	(21)	(3)	17	5	2	(2)	5	(4)	(5)	(7)	(13)	(1%)
Demand Response-600MW	(3)	0	(0)	(1)	0	(0)	0	1	1	(0)	(2)	(0%)
Energy Efficiency-600MW	(18)	(25)	(22)	(8)	(31)	(19)	(5)	(28)	(22)	(4)	(181)	(9%)

Figure 40 shows the production cost savings expressed as the present value in 2017 dollars from 2017 to 2026 for the Central East-Edic-Marcy study after generic solutions were applied.

Figure 40: NYCA-wide Production Cost Savings for Study 1 ($2017M)

Study 1: Central East-Edic-Marcy											
Resource Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Transmission	(17)	(17)	(20)	(19)	(22)	(20)	(6)	(11)	(9)	(10)	(149)
Generation-680MW	(11)	(9)	(9)	(6)	(10)	(9)	(10)	(4)	(8)	(9)	(84)
Demand Response-600MW	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(3)	(2)	(27)
Energy Efficiency-600MW	(90)	(87)	(91)	(91)	(88)	(88)	(80)	(75)	(79)	(76)	(845)

Note: Totals may differ from sum of annual values due to rounding.

The Marcy-New Scotland 345 kV transmission solution is projected to relieve the congestion across existing Marcy-New Scotland transmission lines by 60% in 2021 and 57% in 2026 respectively, as shown in Figure 38. As presented in Figure 40, total ten year NYCA-wide production cost savings is $149 million (2017$) as the result of better utilization of economic generation in the state made available by the large scale transmission upgrades represented by this generic transmission solution.

The generation solution is projected to reduce congestion by 0% in 2021 and 6% in 2026. The ten-year production cost savings of $84 million (2017$) are due to its location downstream of system constraints and the assumed heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G and J Demand Response solution is projected to have no impact on congestion in 2021 and 2026, while the ten-year total production cost savings is $27 million (2017$). DR solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G and J Energy Efficiency solution is projected to reduce congestion by 10% in 2021 and 3% in 2026, while the ten-year total production cost saving is $845 million (2017$). The relatively large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. For this reason EE solutions show significantly greater reductions in production cost than the generation, transmission or demand response solutions.

Study 2: Central East (Base Conditions)

The following generic solutions were applied for Central East study:

- Transmission: A new 345 kV line from Edic to New Scotland, 85 Miles. The new line increases the Central East voltage limit by approximately 580 MW. Cost estimates are: $324M (low); $463M (mid); and $602M (high).
- Generation: A new 680 MW Plant at New Scotland. Cost estimates are: $894M (low); $1,177M (mid); and $1,482M (high).
- Demand Response: 200 MW Demand Response in Zone F; 200 MW in Zone G; 200 MW in Zone J. Cost estimates are $240M (low); $320M (mid); and $400M (high).
- Energy Efficiency: 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 200 MW in Zone J. Cost estimates are $1,100M (low); $1,210M (mid); and $1,320M (high).

Figure 41 shows the Demand$ Congestion of Central East for 2021 and 2026 before and after each of the generic solutions is applied.

Figure 41: Demand$ Congestion Comparison for Study 2 (nominal $M)

Study 2: Central East						
Resource Type	2021			2026		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	398	192	(52%)	215	109	(49%)
Generation-680MW	398	400	0%	215	203	(5%)
Demand Response-600MW	398	399	0%	215	214	(0%)
Energy Efficiency-600MW	398	360	(10%)	215	208	(3%)

Figure 42 shows the Demand$ Congestion reduction for the 10-year Study Period in 2017 dollars from 2017 to 2026 for the Central East study after generic solutions were applied.

Figure 42: Demand$ Congestion Comparison for Study 2 ($2017M)

Study 2: Central East												
Resource Type	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**	**%Change**
Transmission	(74)	(120)	(164)	(166)	(162)	(112)	(55)	(103)	(69)	(60)	(1,086)	(55%)
Generation-680MW	(17)	(5)	15	3	1	(4)	4	(5)	(5)	(7)	(18)	(1%)
Demand Response-600MW	0	1	0	0	1	0	0	1	1	(0)	4	0%
Energy Efficiency-600MW	(9)	(24)	(21)	(7)	(30)	(18)	(5)	(27)	(22)	(4)	(168)	(9%)

Figure 43 shows the NYCA-wide production cost savings expressed as the present value in 2017 dollars from 2017 to 2026 for the Central East study after generic solutions were applied.

Figure 43: NYCA-wide Production Cost Savings for Study 2 ($2017M)

Study 2: Central East											
Resource Type	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Transmission	(11)	(13)	(17)	(13)	(21)	(13)	(6)	(9)	(10)	(11)	(124)
Generation-680MW	(11)	(9)	(9)	(6)	(10)	(9)	(10)	(4)	(8)	(9)	(84)
Demand Response-600MW	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(3)	(2)	(27)
Energy Efficiency-600MW	(90)	(87)	(91)	(91)	(88)	(88)	(80)	(75)	(79)	(76)	(845)

Note: Totals may differ from sum of annual values due to rounding.

The addition of the Edic-New Scotland line is projected to relieve the Central East congestion by 52% in 2021 and 49% in 2026. The total ten-year production cost savings of $124 million (2017$) are again due to increased use of lower cost generation in upstate and increased levels of imports compared to the base case.

The generation solution is projected to reduce congestion by 0% in 2021 and 5% in 2026. The ten-year production cost savings of $84 million (2017$) 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. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G and J Demand Response solution is projected to have a negligible impact on congestion in 2021 and in 2026, while the ten-year total production cost saving is $27 million (2017$). DR solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G, and J Energy Efficiency solution is projected to reduce congestion by 10% in 2021 and 3% in 2026, while the ten-year total production cost saving is $845 million (2017$). The relative large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. EE solutions typically show greater reductions in production cost than the generation, transmission and energy efficiency solutions because load is reduced in all hours reducing the total MWh required to serve load.

Study 3: Central East-New Scotland-Pleasant Valley (Base Conditions)

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, 150 Miles. The new line increases the Central East voltage transfer limit by about 700 MW and the UPNY-SENY thermal capability by approximately 1200 MW. Cost estimates are: $572M (low); $818M (mid); and $1,063M (high).
- Generation: A new 1,360 MW Plant at Pleasant Valley. Cost estimates are: $2,006M (low); $2,660M (mid); and $3,314M (high).
- Demand Response: 200 MW Demand Response in Zone F; 200 MW in Zone G; 800 MW in Zone J. Cost estimates are $735M (low); $980M (mid); and $1,225M (high).
- Energy Efficiency: 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 800 MW in Zone J. Cost estimates are $2,600M (low); $2,860M (mid); and $3,120M (high).

Figure 44 shows the Demand$ Congestion of Central East-New Scotland-Pleasant Valley for 2021 and 2026 before and after each of the generic solutions is applied.

Figure 44: Demand$ Congestion Comparison for Study 3 (nominal $M)

Study 3: Central East-New Scotland-Pleasant Valley						
Resource Type	2021			2026		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	401	209	(48%)	219	127	(42%)
Generation-1360MW	401	382	(5%)	219	223	2%
Demand Response-1200MW	401	401	0%	219	220	0%
Energy Efficiency-1200MW	401	338	(16%)	219	195	(11%)

Figure 45 shows the Demand$ Congestion reduction for the 10-year Study Period in 2017 dollars from 2017 to 2026 for the Central East-New Scotland-Pleasant Valley study after generic solutions were applied.

Figure 45: Demand$ Congestion Comparison for Study 3 ($2017M)

Study 3: Central East-New Scotland-Pleasant Valley												
Resource Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	%Change
Transmission	(75)	(109)	(153)	(162)	(152)	(108)	(47)	(95)	(68)	(52)	(1,020)	(51%)
Generation-1360MW	(16)	10	7	10	(15)	(6)	(5)	(0)	(5)	2	(17)	(1%)
Demand Response-1200MW	(1)	0	0	(0)	0	0	0	2	1	1	3	0%
Energy Efficiency-1200MW	(18)	(6)	(36)	(26)	(49)	(26)	(14)	(41)	(23)	(14)	(253)	(13%)

Figure 46 shows the NYCA-wide production cost savings expressed as the present value in 2017 dollars from 2017 to 2026 for the Central East-New Scotland-Pleasant Valley study after the generic solutions were applied.

Figure 46: NYCA-wide Production Cost Savings for Study 3 ($2017M)

Study 3: Central East-New Scotland-Pleasant Valley											
Resource Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Transmission	(19)	(23)	(27)	(19)	(27)	(19)	(10)	(13)	(13)	(14)	(185)
Generation-1360MW	(30)	(16)	(13)	(11)	(13)	(16)	(13)	(11)	(15)	(13)	(152)
Demand Response-1200MW	(7)	(6)	(6)	(6)	(6)	(5)	(6)	(5)	(5)	(5)	(55)
Energy Efficiency-1200MW	(185)	(180)	(184)	(185)	(177)	(170)	(162)	(150)	(153)	(150)	(1,696)

Note: Totals may differ from sum of annual values due to rounding.

The Edic-New Scotland-Pleasant Valley 345 kV transmission solution is projected to relieve the congestion across existing Central East-New Scotland-Pleasant Valley corridor by 48% in 2021 and 42% in 2026 respectively, as shown in Figure 44. As presented in Figure 46, total ten year NYCA-wide production cost savings is $185 million (2017$) 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 is projected to reduce congestion by 5% in 2021 and increase congestion by 2% in 2026. The ten-year production cost savings of $152 million (2017$) are due to its location downstream of system constraints and the assumed heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions can replace less efficient NYCA generation upstream of the load centers which can have the effect of reducing differentials across the constraints. The displacement of certain Capital zone generation, however, may lower the Central East voltage transfer limit and actually increase congestion under certain circumstances. The running of lower-cost generation will in general lower production cost as well.

The Zones F, G and J Demand Response solution is projected to have a negligible impact on congestion in 2021 and 2026, while the ten-year total production cost saving is $55 million (2017$). DR solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G and J Energy Efficiency solution is projected to reduce congestion by 16% in 2021 and 11% in 2026, while the ten-year total production cost saving is $1,696 million (2017$). The relatively large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. For this reason, EE solutions show significantly greater reductions in production cost than the generation, transmission or demand response solutions.

Study 4: Central East-New Scotland-Pleasant Valley (Edic-Marcy relaxed)

The following generic solutions were applied for Central East-New Scotland-Pleasant Valley (Edic-Marcy relaxed) Study:

- Transmission: A new 345 kV line from Edic to New Scotland to Pleasant Valley, 150 Miles. The new line increases the Central East voltage transfer limit by about 700 MW and the UPNY-SENY thermal capability by approximately 1,200 MW. Cost estimates are: $572M (low); $818M (mid); and $1,063M (high).

- Generation: A new 1,360 MW Plant at Pleasant Valley. Cost estimates are: $2,006M (low); $2,660M (mid); and $3,314M (high).

- Demand Response: 200 MW Demand Response in Zone F; 200 MW in Zone G; 800 MW in Zone J. Cost estimates are $735M (low); $980M (mid); and $1,225M (high).

- Energy Efficiency: 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 800 MW in Zone J. Cost estimates are $2,600M (low); $2,860M (mid); and $3,120M (high).

Figure 47 shows the Demand$ Congestion of Central East -New Scotland-Pleasant Valley (Edic-Marcy relaxed) for 2021 and 2026 before and after each of the generic solutions is applied. The Base Case congestion numbers, $503M for 2021 and $307M for 2026, are taken directly from Figure 35 representing the level of congestion of the Study 4 before the solutions. In Study 4, Edic-Marcy is relaxed in both the Base Case and Solution cases.

Figure 47: Demand$ Congestion Comparison for Study 4 (nominal $M)

Study 4: Study 3 with Edic-Marcy relaxed						
Resource Type	2021			2026		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	503	223	(56%)	307	138	(55%)
Generation-1360MW	503	477	(5%)	307	321	5%
Demand Response-1200MW	503	503	0%	307	308	0%
Energy Efficiency-1200MW	503	440	(13%)	307	270	(12%)

Figure 48 shows the Demand$ Congestion reduction for the 10-year Study Period in 2017 dollars from 2017 to 2026 for the Central East-New Scotland-Pleasant Valley (Edic-Marcy relaxed) study after generic solutions were applied.

Figure 48: Demand$ Congestion Comparison for Study 4 ($2017M)

Study 4: Study 3 with Edic-Marcy relaxed												
Resource Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	%Change
Transmission	(95)	(157)	(222)	(230)	(222)	(161)	(94)	(140)	(87)	(95)	(1,504)	(58%)
Generation-1360MW	(9)	28	9	19	(21)	(13)	(5)	2	4	8	20	1%
Demand Response-1200MW	(0)	1	(1)	(0)	(0)	1	(0)	(0)	1	1	1	0%
Energy Efficiency-1200MW	(17)	(11)	(48)	(44)	(50)	(40)	(28)	(51)	(15)	(21)	(326)	(13%)

Figure 49 shows the production cost savings expressed as the present value in 2017 dollars from 2017 to 2026 for the Central East-New Scotland-Pleasant Valley (Edic-Marcy relaxed) study after generic solutions were applied.

Figure 49: NYCA-wide Production Cost Savings for Study 4 ($2017M)

Study 4: Study 3 with Edic-Marcy relaxed											
Resource Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Transmission	(20)	(24)	(26)	(29)	(26)	(20)	(12)	(17)	(11)	(11)	(197)
Generation-1360MW	(33)	(18)	(14)	(13)	(8)	(13)	(15)	(13)	(16)	(14)	(159)
Demand Response-1200MW	(6)	(6)	(6)	(6)	(5)	(5)	(5)	(5)	(4)	(5)	(54)
Energy Efficiency-1200MW	(190)	(186)	(188)	(187)	(176)	(173)	(164)	(157)	(156)	(152)	(1,728)

Note: Totals may differ from sum of annual values due to rounding.

The Edic-New Scotland-Pleasant Valley 345 kV transmission solution is projected to relieve the congestion across the existing Central East-New Scotland-Pleasant Valley transmission corridor by 56% in 2021 and 55% in 2026 respectively, as shown in Figure 47. As presented in Figure 40, total ten year NYCA-wide production cost savings is $197million (2017$) 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 is projected to reduce congestion by 5% in 2021 and increase congestion by 5% in 2026. The ten-year production cost savings of $159 million (2017$) are due to due to its location downstream of system constraints and the assumed heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions can replace less efficient NYCA generation upstream of the load centers, which can have the effect of reducing differentials across the constraints. The displacement of certain Capital zone generation, however, may lower the Central East voltage transfer limit and actually increase congestion under certain circumstances. The running of lower-cost generation will in general lower production cost as well.

The Zones F, G and J Demand Response solution is projected to have a negligible impact on congestion in 2021 and in 2026, while the ten-year total production cost saving is $54 million (2017$). DR solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G and J Energy Efficiency solution is projected to reduce congestion by 13% in 2021 and 12% in 2026, while the ten-year total production cost saving is $1,728 million (2017$). The relatively large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. For this reason, EE solutions show significantly greater reductions in production cost than the generation, transmission or demand response solutions.

Study 5: Central East-New Scotland-Pleasant Valley (System Resource Shift)

The following generic solutions were applied for Central East-New Scotland-Pleasant Valley (System Resource Shift) study:

- Transmission: A new 345 kV line from Edic to New Scotland to Pleasant Valley, 150 Miles. The new line increases the Central East voltage transfer limit by about 700 MW and the UPNY-SENY thermal capability by approximately 1200 MW. Cost estimates are: $572M (low); $818M (mid); and $1,063M (high).
- Generation: A new 1,360 MW Plant at Pleasant Valley. Cost estimates are: $2,006M (low); $2,660M (mid); and $3,314M (high).
- Demand Response: 200 MW Demand Response in Zone F; 200 MW in Zone G; 800 MW in Zone J. Cost estimates are $735M (low); $980M (mid); and $1,225M (high).
- Energy Efficiency: 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 800 MW in Zone J. Cost estimates are $2,600M (low); $2,860M (mid); and $3,120M (high).

Figure 50 shows the Demand$ Congestion of Central East for 2021 and 2026 before and after each of the generic solutions is applied.

Figure 50: Demand$ Congestion Comparison for Study 5 (nominal $M)

Study 5: Study 3 under System Resource Shift Case						
Resource Type	2021			2026		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	508	258	(49%)	1,020	536	(47%)
Generation-1360MW	508	520	2%	1,020	1,006	(1%)
Demand Response-1200MW	508	509	0%	1,020	1,021	0%
Energy Efficiency-1200MW	508	470	(7%)	1,020	908	(11%)

Figure 51 shows the Demand$ Congestion reduction for the 10-year Study Period in 2017 dollars from 2017 to 2026 for the Central East-New Scotland-Pleasant Valley (System Resource Shift)study after generic solutions were applied.

Figure 51: Demand$ Congestion Comparison for Study 5 ($2017M)

Study 5: Study 3 under System Resource Shift Case												
Resource Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	%Change
Transmission	(69)	(116)	(210)	(231)	(197)	(186)	(119)	(189)	(179)	(272)	(1,770)	(52%)
Generation-1360MW	(19)	19	5	7	9	6	(10)	11	(20)	(7)	1	0%
Demand Response-1200MW	1	(0)	1	(1)	1	(1)	(0)	(1)	(0)	1	1	0%
Energy Efficiency-1200MW	(9)	(19)	(42)	(41)	(30)	(21)	(32)	(24)	(35)	(63)	(316)	(9%)

Figure 52 shows the NYCA-wide production cost savings expressed as the present value in 2017 dollars from 2017 to 2026 for the Central East-New Scotland-Pleasant Valley (System Resource Shift) study after generic solutions were applied.

Figure 52: NYCA-wide Production Cost Savings for Study 5 ($2017M)

Study 5: Study 3 under System Resource Shift Case											
Resource Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Transmission	(20)	(25)	(34)	(32)	(38)	(35)	(20)	(33)	(24)	(37)	(298)
Generation-1360MW	(29)	(19)	(16)	(19)	(20)	(15)	(22)	(19)	(25)	(20)	(204)
Demand Response-1200MW	(7)	(6)	(6)	(6)	(6)	(6)	(5)	(5)	(5)	(5)	(55)
Energy Efficiency-1200MW	(182)	(177)	(183)	(186)	(183)	(171)	(163)	(154)	(148)	(142)	(1,689)

Note: Totals may differ from sum of annual values due to rounding.

The addition of the Central East-New Scotland-Pleasant Valley line is projected to relieve congestion by 49% in 2021 and 47% in 2026. The total ten-year production cost savings of $298 million (2017$) are again due to increased use of lower cost generation in upstate and increased levels of imports compared to the base case.

The generation solution is projected to increase congestion by 2% in 2021 and reduce congestion by 1% in 2026. The ten-year production cost savings of $204 million (2017$) 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. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G and J Demand Response solution is projected to have negligible impact on congestion in 2021 and in 2026, while the ten-year total production cost saving is $55 million (2017$). DR solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G, and J Energy Efficiency solution is projected to reduce congestion by 7% in 2021 and 11% in 2026, while the ten-year total production cost saving is $1,589 million (2017$). The relatively large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. For this reason, EE solutions show greater reductions in production cost than the generation, transmission and energy efficiency solutions.

Study 6: Central East-New Scotland-Pleasant Valley (System Resource Shift, Edic-Marcy relaxed)

The following generic solutions were applied for the Central East-New Scotland-Pleasant Valley (System Resource Shift, Edic-Marcy relaxed) study:

- Transmission: A new 345 kV line from Edic to New Scotland to Pleasant Valley, 150 Miles. The new line increases the Central East voltage transfer limit by about 700 MW and the UPNY-SENY thermal capability by approximately 1200 MW. Cost estimates are: $572M (low); $818M (mid); and $1,063M (high).
- Generation: A new 1,360 MW Plant at Pleasant Valley. Cost estimates are: $2,006M (low); $2,660M (mid); and $3,314M (high).
- Demand Response: 200 MW Demand Response in Zone F; 200 MW in Zone G; 800 MW in Zone J. Cost estimates are $735M (low); $980M (mid); and $1,225M (high).
- Energy Efficiency: 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 800 MW in Zone J. Cost estimates are $2,600M (low); $2,860M (mid); and $3,120M (high).

Figure 53 shows the Demand$ Congestion of Central East-New Scotland-Pleasant Valley (System Resource Shift, Edic-Marcy relaxed) for 2021 and 2026 before and after each of the generic solutions is applied. In Study 6, Edic-Marcy is relaxed in both the base case and solution cases.

Figure 53: Demand$ Congestion Comparison for Study 6 (nominal $M)

Study 6: Study 5 with Edic-Marcy relaxed						
Resource Type	2021			2026		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	604	321	(47%)	1,121	619	(45%)
Generation-1360MW	604	614	2%	1,121	1,099	(2%)
Demand Response-1200MW	604	602	(0%)	1,121	1,123	0%
Energy Efficiency-1200MW	604	576	(5%)	1,121	1,003	(11%)

Figure 54 shows the Demand$ Congestion reduction for the 10-year Study Period in 2017 dollars from 2017 to 2026 for the Central East-New Scotland -Pleasant Valley (System Resource Shift)study after generic solutions were applied.

Figure 54: Demand$ Congestion Comparison for Study 6 ($2017M)

Study 6: Study 5 with Edic-Marcy relaxed												
Resource Type	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**	**%Change**
Transmission	(92)	(168)	(254)	(271)	(223)	(245)	(155)	(227)	(192)	(283)	(2,110)	(51%)
Generation-1360MW	(7)	7	2	14	8	12	5	9	(21)	(12)	17	0%
Demand Response-1200MW	0	1	2	0	(1)	1	2	(1)	(1)	1	3	0%
Energy Efficiency-1200MW	(14)	(26)	(74)	(52)	(22)	(24)	(46)	(39)	(39)	(66)	(402)	(10%)

Figure 55 shows the Demand$ Congestion reduction for the 10-year Study Period in 2017 dollars from 2017 to 2026 for the Central East-New Scotland-Pleasant Valley (System Resource Shift)study after generic solutions were applied.

Figure 55: NYCA-wide Production Cost Savings for Study 6 ($2017M)

Study 6: Study 5 with Edic-Marcy relaxed											
Resource Type	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Transmission	(22)	(27)	(33)	(35)	(45)	(36)	(25)	(34)	(25)	(38)	(319)
Generation-1360MW	(32)	(19)	(14)	(17)	(21)	(20)	(24)	(20)	(26)	(19)	(211)
Demand Response-1200MW	(7)	(6)	(6)	(6)	(6)	(5)	(5)	(6)	(5)	(5)	(56)
Energy Efficiency-1200MW	(187)	(182)	(182)	(182)	(184)	(174)	(167)	(153)	(150)	(140)	(1,700)

Note: Totals may differ from sum of annual values due to rounding.

The addition of the Central East-New Scotland-Pleasant Valley line is projected to relieve congestion by 47% in 2021 and 45% in 2026, and results in a projected total ten-year production cost savings of $319 million (2017$).

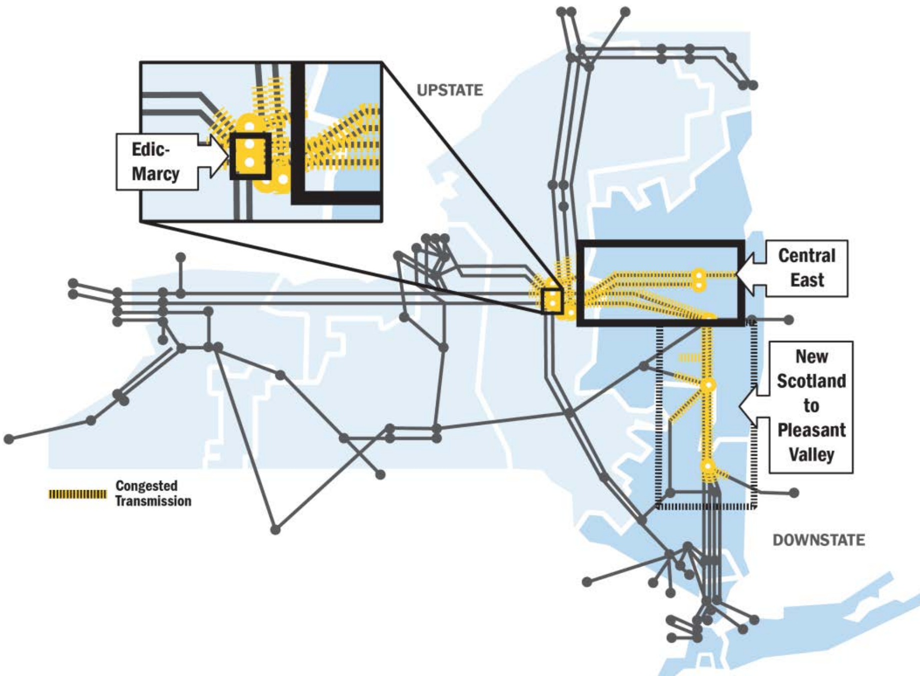
The generation solution is projected to increase congestion by 2% in 2021 and reduce congestion by 2% in 2026. The ten-year production cost savings of $211 million (2017$) are due to its location downstream of system constraints and the assumed better heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G and J Demand Response solution is projected to have negligible impact on congestion in 2021 and in 2026, while the ten-year total production cost saving is $56 million (2017$). DR solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G, and J Energy Efficiency solution is projected to reduce congestion by 5% in 2021 and 11% in 2026, while the ten-year total production cost saving is $1,700 million (2017$). The relatively large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. For this reason, EE solutions show greater reductions in production cost than the generation and transmission solutions.

The NYCA-wide production cost savings of the four generic solutions for the six studies are summarized and shown in Figure 56.

Figure 56: Total NYCA-wide Production Cost Savings 2017-2026 ($2017M)



Study 1: Central East-Edic-Marcy	
Solution	**Production Cost Savings ($2017M)**
Transmission	149
Generation	84
Demand Response	27
Energy Efficiency	845

Study 2: Central East	
Solution	**Production Cost Savings ($2017M)**
Transmission	124
Generation	84
Demand Response	27
Energy Efficiency	845

Study 3: Central East-New Scotland-Pleasant Valley	
Solution	**Production Cost Savings ($2017M)**
Transmission	185
Generation	152
Demand Response	55
Energy Efficiency	1,696

Study 4: Study 3 with Edic-Marcy relaxed	
Solution	**Production Cost Savings ($2017M)**
Transmission	197
Generation	159
Demand Response	54
Energy Efficiency	1,728

Study 5: Study 3 under System Resource Shift Case	
Solution	**Production Cost Savings ($2017M)**
Transmission	298
Generation	204
Demand Response	55
Energy Efficiency	1,689

Study 6: Study 5 with Edic-Marcy relaxed	
Solution	**Production Cost Savings ($2017M)**
Transmission	319
Generation	211
Demand Response	56
Energy Efficiency	1,700

Benefit/Cost Analysis

The NYISO conducted the benefit/cost analysis for each generic solution applied to the six studies as described above. The CARIS benefit/cost analysis assumes a levelized generic carrying charge rate of 15% 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 5.3.2 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 15% 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,[29] using a discount rate of 6.99%, and the 15% carrying charge rate, yielding a capital recovery factor equal to 1.09.

Cost for the demand response and energy efficiency solutions are intended to be comparable to the overnight installation costs of a generic transmission facility or generating unit and, therefore, represent equipment purchase and installation costs. Recognizing that these costs vary by region, zonal-specific costs were developed utilizing Transmission Owner data reported to the NYPSC in energy efficiency and demand response proceedings.

Cost Analysis

Figure 57 includes the total cost estimate for each generic solution based on the unit pricing and the detailed cost breakdown for each solution included in Appendix E. Such costs may differ from those submitted by potential developers in a competitive bidding process. These are simplified estimates of overnight installation costs and do not include any of the many 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.

29 The carrying charge rate of 15% 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 31.5.3.3.4.

Figure 57: Generic Solution Overnight Costs for Each Study[30]

Generic Solutions Cost Summary ($M)						
Studies	Central East-Edic-Marcy (Study 1)	Central East (Study 2)	Central East-New Scotland-Pleasant Valley (Study 3)	Central East-New Scotland-Pleasant Valley (Study 4)	Central East-New Scotland-Pleasant Valley (Study 5)	Central East-New Scotland-Pleasant Valley (Study 6)
TRANSMISSION						
Transmission Path	Marcy-New Scotland	Edic-New Scotland	Edic-New Scotland-Pleasant Valley	Edic-New Scotland-Pleasant Valley	Edic-New Scotland-Pleasant Valley	Edic-New Scotland-Pleasant Valley
Voltage	345 kV	345 kV	345 kV	345 kV	345 kV	345 kV
Miles	85	85	150	150	150	150
High	$553	$553	$975	$975	$975	$975
Mid	$425	$425	$750	$750	$750	$750
Low	$298	$298	$525	$525	$525	$525
GENERATION						
Unit Siting	New Scotland	New Scotland	Pleasant Valley	Pleasant Valley	Pleasant Valley	Pleasant Valley
# of 340 MW Blocks	2	2	4	4	4	4
High	$1,360	$1,360	$3,040	$3,040	$3,040	$3,040
Mid	$1,080	$1,080	$2,440	$2,440	$2,440	$2,440
Low	$820	$820	$1,840	$1,840	$1,840	$1,840
DEMAND RESPONSE						
Location (# of Blocks)	F(1), G(1) and J(1)	F(1), G(1) and J(1)	F(1), G(1) and J(4)	F(1), G(1) and J(4)	F(1), G(1) and J(4)	F(1), G(1) and J(4)
Total # of 200MW Blocks	3	3	6	6	6	6
High	$400	$400	$1,225	$1,225	$1,225	$1,225
Mid	$320	$320	$980	$980	$980	$980
Low	$240	$240	$735	$735	$735	$735
ENERGY EFFICIENCY						
Location (# of Blocks)	F(1), G(1) and J(1)	F(1), G(1) and J(1)	F(1), G(1) and J(4)	F(1), G(1) and J(4)	F(1), G(1) and J(4)	F(1), G(1) and J(4)
Total # of 200MW Blocks	3	3	6	6	6	6
High	$1,320	$1,320	$3,120	$3,120	$3,120	$3,120
Mid	$1,210	$1,210	$2,860	$2,860	$2,860	$2,860
Low	$1,100	$1,100	$2,600	$2,600	$2,600	$2,600

Primary Metric Results

The primary benefit metric for the three CARIS studies is the reduction in NYCA-wide production costs. Figure 58 shows the production cost savings used to calculate the benefit/cost ratios for the generic solutions. In each of the six studies, the Energy Efficiency solution produced the highest production cost savings because it directly reduces the energy production requirements. Similarly, in each study, the transmission solutions produced higher production cost savings than generation. In all cases, the Demand Response solution had the least impact on production cost savings due to the limited hours impacted by the solution.

Figure 58: Production Cost Generic Solutions Savings 2017-2026 ($2017M)

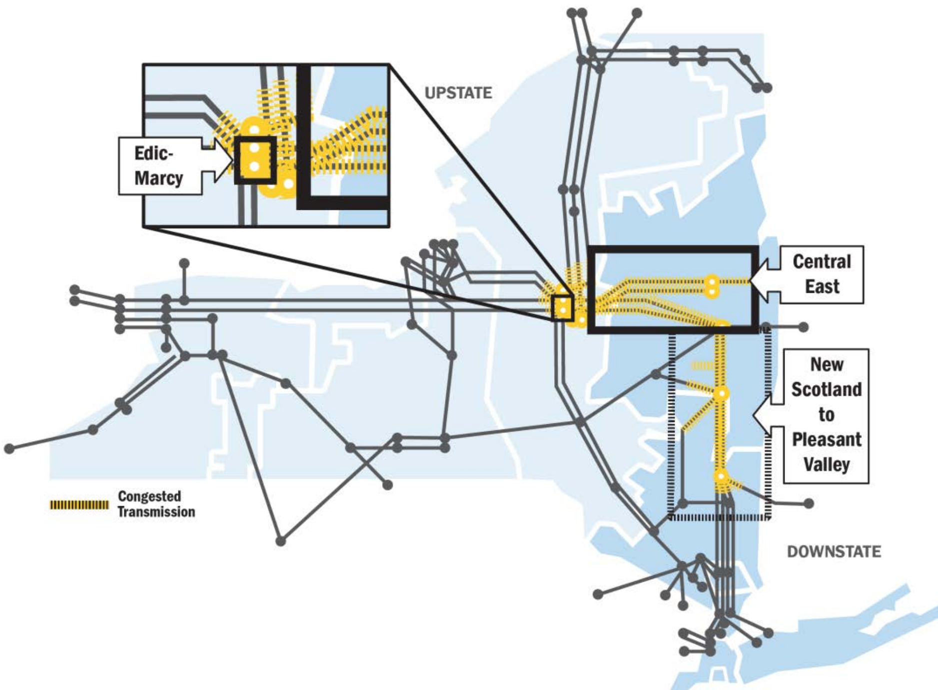
Study	Ten-Year Production Cost Savings ($2017M)			
	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Study 1: Central East-Edic-Marcy	149	84	27	845
Study 2: Central East	124	84	27	845
Study 3: Central East-New Scotland-Pleasant Valley	185	152	55	1,696
Study 4: Study 3 with Edic-Marcy relaxed	197	159	54	1,728
Study 5: Study 3 under System Resource Shift Case	298	204	55	1,689
Study 6: Study 5 with Edic-Marcy relaxed	319	211	56	1,700

30 Appendix E contains a more detailed description of the derivation of the generic solution costs.

Benefit/Cost Ratios

Figure 59 shows the benefit/cost ratios for each study and each generic solution.

Figure 59: B/C Ratios (High, Mid, and Low Cost Estimate Ranges)



Study 1: Central East-Edic-Marcy			
Solution	**Low**	**Mid**	**High**
Transmission	0.46	0.32	0.25
Generation	0.09	0.07	0.06
Demand Response	0.11	0.08	0.07
Energy Efficiency	0.77	0.70	0.64

Study 4: Study 3 with Edic-Marcy relaxed			
Solution	**Low**	**Mid**	**High**
Transmission	0.34	0.24	0.19
Generation	0.08	0.06	0.05
Demand Response	0.07	0.06	0.04
Energy Efficiency	0.66	0.60	0.55

Study 2: Central East			
Solution	**Low**	**Mid**	**High**
Transmission	0.38	0.27	0.21
Generation	0.09	0.07	0.06
Demand Response	0.11	0.08	0.07
Energy Efficiency	0.77	0.70	0.64

Study 5: Study 3 under System Resource Shift Case			
Solution	**Low**	**Mid**	**High**
Transmission	0.52	0.36	0.28
Generation	0.10	0.08	0.06
Demand Response	0.07	0.06	0.04
Energy Efficiency	0.65	0.59	0.54

Study 3: Central East-New Scotland-Pleasant Valley			
Solution	**Low**	**Mid**	**High**
Transmission	0.32	0.23	0.17
Generation	0.08	0.06	0.05
Demand Response	0.07	0.06	0.04
Energy Efficiency	0.65	0.59	0.54

Study 6: Study 5 with Edic-Marcy relaxed			
Solution	**Low**	**Mid**	**High**
Transmission	0.56	0.39	0.30
Generation	0.11	0.08	0.06
Demand Response	0.08	0.06	0.05
Energy Efficiency	0.65	0.59	0.54

Additional Metrics Results

Additional metrics, which are provided for information purposes in Phase 1, are presented in Figure 60, Figure 61, Figure 62 and Figure 63 to show the 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 case values less the base case values for all the metrics except for the ICAP metric. While all but the ICAP metric are from the production cost simulation program, the ICAP metric is computed using the latest available information from the installed reserve margin (IRM), locational capacity requirement (LCR), and ICAP Demand Curves.[31] The procedure for determining the MW impacts, as prescribed in the NYISO OATT[32], does not replicate that methodology employed in determining the Installed Reserve Margin and Locational Capacity Requirements in order to forecast changes to such requirements that would be expected with the addition of the actual generic solutions.

For Variant 1, the ISO measured the cost impact of a solution by multiplying the forecast cost per megawatt-year of Installed Capacity (without the solution in place) by the sum of the megawatt impact. For Variant 2, the cost impact of a solution is calculated by forecasting the difference in cost per megawatt-year of Installed Capacity with and without the solution in place and multiplying that difference by fifty percent (50%) of the assumed amount of NYCA Installed Capacity available. Details on the ICAP metric calculations and 10 years of results are provided in Appendix E.

31 http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/ICAP_Auctions/2017/Summer_2017/Documents/ICAP_Translation_of_Demand_Curve_Summer_2017.pdf;
http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Resource_Adequacy/Resource_Adequacy_Documents/LCR2017_Report.pdf

32 Section 31.3.1.3.5.6 of the NYISO OATT.

Figure 60: Ten-Year Change in Load Payments, Generator Payments, TCC Payments and Losses Costs ($2017M)[33]

Study	Solution	LOAD PAYMENT	NYCA LOAD PAYMENT	EXPORT PAYMENT	GENERATOR PAYMENT	NYCA GENERATOR PAYMENT	IMPORT PAYMENT	TCC PAYMENT	LOSSES COSTS
TRANSMISSION SOLUTIONS									
Study 1: Central East-Edic-Marcy	MARCY-NSL	$490	$328	$162	$499	$384	$115	($307)	($112)
Study 2: Central East	EDIC-NSL	$201	$127	$74	$263	$217	$46	($266)	($150)
Study 3: Central East-New Scotland-Pleasant Valley	EDIC-NSL-PV	$293	$207	$86	$302	$213	$89	($253)	($245)
Study 4: Study 3 with Edic-Marcy relaxed	EDIC-NSL-PV	$416	$282	$134	$469	$373	$96	($409)	($195)
Study 5: Study 3 under System Resource Shift Case	EDIC-NSL-PV	$444	$370	$74	$644	$528	$116	($554)	($187)
Study 6: Study 5 with Edic-Marcy relaxed	EDIC-NSL-PV	$578	$468	$110	$784	$637	$147	($656)	($145)
GENERATION SOLUTIONS									
Study 1: Central East-Edic-Marcy	New Scotland	($30)	($62)	$32	($33)	$32	($65)	$2	$12
Study 2: Central East	New Scotland	($30)	($62)	$32	($33)	$32	($65)	$2	$12
Study 3: Central East-New Scotland-Pleasant Valley	Pleasant Valley	($194)	($269)	$75	($140)	$30	($170)	($18)	($45)
Study 4: Study 3 with Edic-Marcy relaxed	Pleasant Valley	($163)	($239)	$76	($127)	$32	($159)	$9	($52)
Study 5: Study 3 under System Resource Shift Case	Pleasant Valley	($175)	($283)	$108	($100)	$82	($182)	($33)	($48)
Study 6: Study 5 with Edic-Marcy relaxed	Pleasant Valley	($131)	($223)	$92	($63)	$95	($158)	($29)	($53)
DEMAND RESPONSE SOLUTIONS									
Study 1: Central East-Edic-Marcy	F(200) G(200) J(200)	($32)	($33)	$1	($18)	($8)	($10)	($11)	($2)
Study 2: Central East	F(200) G(200) J(200)	($32)	($33)	$1	($18)	($8)	($10)	($11)	($2)
Study 3: Central East-New Scotland-Pleasant Valley	F(200) G(200) J(800)	($74)	($77)	$3	($42)	($25)	($17)	($27)	($4)
Study 4: Study 3 with Edic-Marcy relaxed	F(200) G(200) J(800)	($80)	($83)	$3	($46)	($29)	($17)	($28)	($6)
Study 5: Study 3 under System Resource Shift Case	F(200) G(200) J(800)	($73)	($77)	$4	($38)	($24)	($14)	($33)	($1)
Study 6: Study 5 with Edic-Marcy relaxed	F(200) G(200) J(800)	($80)	($84)	$4	($44)	($31)	($13)	($32)	($4)
ENERGY EFFICIENCY SOLUTIONS									
Study 1: Central East-Edic-Marcy	F(200) G(200) J(200)	($1,128)	($1,274)	$146	($994)	($819)	($175)	($105)	($67)
Study 2: Central East	F(200) G(200) J(200)	($1,128)	($1,274)	$146	($994)	($819)	($175)	($105)	($67)
Study 3: Central East-New Scotland-Pleasant Valley	F(200) G(200) J(800)	($2,287)	($2,551)	$264	($1,967)	($1,639)	($328)	($243)	($170)
Study 4: Study 3 with Edic-Marcy relaxed	F(200) G(200) J(800)	($2,238)	($2,493)	$255	($1,922)	($1,612)	($310)	($246)	($166)
Study 5: Study 3 under System Resource Shift Case	F(200) G(200) J(800)	($2,270)	($2,575)	$305	($1,921)	($1,620)	($301)	($285)	($161)
Study 6: Study 5 with Edic-Marcy relaxed	F(200) G(200) J(800)	($2,262)	($2,544)	$282	($1,911)	($1,611)	($300)	($297)	($159)

Note: A negative number implies a reduction in payments

33 Load Payments and Generator Payments are Tariff-defined additional metrics. The NYCA Load Payment and Export Payment values provide a breakdown of Load Payments by internal and external loads; NYCA Generator Payment and Import Payment provide a breakdown of Generator Payments by internal and external generators.

Figure 61: Year 2026 ICAP MW Impact

Study	Solution	ICAP Impact (MW)			
		J	G-J	K	NYCA
Study 1: Central East-Edic-Marcy	Transmission	14	24	8	61
	Generation	74	126	40	313
	Energy Efficiency	131	222	71	552
	Demand Response	130	221	70	548
Study 2: Central East	Transmission	14	24	8	61
	Generation	74	126	40	313
	Energy Efficiency	131	222	71	552
	Demand Response	130	221	70	548
Study 3: Central East-New Scotland-Pleasant Valley	Transmission	14	24	8	61
	Generation	100	171	54	424
	Energy Efficiency	324	549	175	1,362
	Demand Response	334	567	181	1,408
Study 4: Study 3 with Edic-Marcy relaxed	Transmission	14	24	8	61
	Generation	100	171	54	424
	Energy Efficiency	324	549	175	1,362
	Demand Response	334	567	181	1,408
Study 5: Study 3 under System Resource Shift Case	Transmission	19	30	12	99
	Generation	31	49	19	162
	Energy Efficiency	551	874	341	2,897
	Demand Response	562	891	348	2,954
Study 6: Study 5 with Edic-Marcy relaxed	Transmission	19	30	12	99
	Generation	31	49	19	162
	Energy Efficiency	551	874	341	2,897
	Demand Response	562	891	348	2,954

Figure 62: Cumulative ICAP Impact ($2017M)

Study	Solution	ICAP Saving ($2017M)	
		V1	V2
Study 1: Central East-Edic-Marcy	Transmission	11	136
	Generation	60	662
	Energy Efficiency	106	1,065
	Demand Response	105	1,058
Study 2: Central East	Transmission	11	136
	Generation	60	662
	Energy Efficiency	106	1,065
	Demand Response	105	1,058
Study 3: Central East-New Scotland-Pleasant Valley	Transmission	11	136
	Generation	81	851
	Energy Efficiency	261	2,206
	Demand Response	270	2,253
Study 4: Study 3 with Edic-Marcy relaxed	Transmission	11	136
	Generation	81	851
	Energy Efficiency	261	2,206
	Demand Response	270	2,253
Study 5: Study 3 under System Resource Shift Case	Transmission	16	185
	Generation	26	294
	Energy Efficiency	455	3,059
	Demand Response	464	3,100
Study 6: Study 5 with Edic-Marcy relaxed	Transmission	16	185
	Generation	26	294
	Energy Efficiency	455	3,059
	Demand Response	464	3,100

The ten-year changes in total New York emissions resulting from the application of generic solutions are reported in Figure 63 below. The base case ten-year emission totals for NYCA are: CO_2 = 265,823 thousand-tons, SO_2 = 21,922 tons and NO_X = 134,952 tons. The study results reveal that all of the generic solutions impact emissions by less than 6% for CO_2 emissions. Energy efficiency had the most significant impact with reductions in the 3%-6% range. Generation solutions slightly increased the CO_2 emissions in the range of 0.2% - 0.7% due an increase in New York generation and an associated decrease in imports. Demand response had reductions of less than 0.2% in CO_2 emissions. SO_2 emission impacts ranged from an increase of 16% for Study 3 transmission solution to a reduction of 3.1% for the Study 4 energy efficiency solution. The NO_X emission impacts ranged from an increase of 2% for the Study 5 generation solution to a reduction of 3.7% for the Study 6 energy efficiency solution.

Figure 63: Ten-Year Change in NYCA CO_2, SO_2 and NO_X Emissions

Study	Solution	SO_2		CO_2		NO_X	
		Tons	Cost ($2017M)	1000 Tons	Cost ($2017M)	Tons	Cost ($2017M)
TRANSMISSION SOLUTIONS							
Study 1: Central East-Edic-Marcy	MARCY-NSL	1,663	$0	(130)	$1	1,054	$0
Study 2: Central East	EDIC-NSL	3,168	$0	203	$4	1,431	$0
Study 3: Central East-New Scotland-Pleasant Valley	EDIC-NSL-PV	3,569	$0	(575)	$2	1,253	$0
Study 4: Study 3 with Edic-Marcy relaxed	EDIC-NSL-PV	2,078	$0	(673)	$1	564	$0
Study 5: Study 3 under System Resource Shift Case	EDIC-NSL-PV	31	$0	(3,842)	($13)	334	$0
Study 6: Study 5 with Edic-Marcy relaxed	EDIC-NSL-PV	(1)	$0	(3,955)	($15)	344	$0
GENERATION SOLUTIONS							
Study 1: Central East-Edic-Marcy	New Scotland	(359)	$0	460	$3	837	$0
Study 2: Central East	New Scotland	(359)	$0	460	$3	837	$0
Study 3: Central East-New Scotland-Pleasant Valley	Pleasant Valley	(429)	$0	1,558	$12	2,070	$0
Study 4: Study 3 with Edic-Marcy relaxed	Pleasant Valley	(408)	$0	1,555	$10	2,147	$0
Study 5: Study 3 under System Resource Shift Case	Pleasant Valley	600	$0	1,947	$15	2,910	$1
Study 6: Study 5 with Edic-Marcy relaxed	Pleasant Valley	682	$0	1,451	$11	2,774	$0
DEMAND RESPONSE SOLUTIONS							
Study 1: Central East-Edic-Marcy	F(200) G(200) J(200)	15	$0	(220)	($1)	(105)	$0
Study 2: Central East	F(200) G(200) J(200)	15	$0	(220)	($1)	(105)	$0
Study 3: Central East-New Scotland-Pleasant Valley	F(200) G(200) J(800)	32	$0	(484)	($2)	(399)	$0
Study 4: Study 3 with Edic-Marcy relaxed	F(200) G(200) J(800)	(55)	$0	(489)	($2)	(424)	$0
Study 5: Study 3 under System Resource Shift Case	F(200) G(200) J(800)	(12)	$0	(533)	($2)	(606)	$0
Study 6: Study 5 with Edic-Marcy relaxed	F(200) G(200) J(800)	(36)	$0	(574)	($2)	(645)	$0
ENERGY EFFICIENCY SOLUTIONS							
Study 1: Central East-Edic-Marcy	F(200) G(200) J(200)	(41)	$0	(7,551)	($30)	(1,970)	$0
Study 2: Central East	F(200) G(200) J(200)	(41)	$0	(7,551)	($30)	(1,970)	$0
Study 3: Central East-New Scotland-Pleasant Valley	F(200) G(200) J(800)	(165)	$0	(15,861)	($61)	(4,633)	$0
Study 4: Study 3 with Edic-Marcy relaxed	F(200) G(200) J(800)	(681)	$0	(16,422)	($65)	(4,854)	$0
Study 5: Study 3 under System Resource Shift Case	F(200) G(200) J(800)	(420)	$0	(15,618)	($60)	(4,855)	$0
Study 6: Study 5 with Edic-Marcy relaxed	F(200) G(200) J(800)	(419)	$0	(16,012)	($62)	(4,993)	$0

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 magnitude of congestion costs. The CARIS scenarios were presented to ESPWG and modified based upon the input received and the availability of NYISO resources. The focus of these analyses was to examine the impact of fuel price and load forecast uncertainties, the implementation of a national CO_2 program in 2024, and potential Western and AC public policy transmission upgrades being constructed in concert with a resource mix reflective of the System Resource Shift case (i.e., a resource build-out consistent with the Clean Energy Standard, and the retirement of New York coal units, and Indian Point Energy Center (IPEC)). The objective of the scenario analysis is to determine how congestion patterns are influenced by variables that differ from their base case values. The simulations were conducted for the horizon year, 2026, only.

The following section describes each of the scenarios studied in CARIS Phase 1. The scenarios consider the effects of changes to the "Business as Usual" baseline case (BAU), and the data presented is the change in metrics relative to the BAU case.

Scenario 1: Higher Load Forecast

This scenario examined the impact of a higher load forecast on the cost of congestion. The high load forecast was developed by adjusting upward the annual growth rates for each NYCA zone in the Base load forecast. These higher growth rates reflect faster economic growth than that embedded in the Gold Book forecasts over the study period. In this scenario NYCA energy was forecasted to grow at 0.11% annually (vs. a decline of 0.03% annually over the Study Period in the Base Case). This resulted in the annual NYCA energy forecast in 2026 being 5 TWh (or 3.3%) above the Base forecast. The forecasted growth rates by NYCA Load Zone for the Higher load forecast are presented in Appendix J.

Scenario 2: Lower Load Forecast

This scenario examined the impact of a lower load forecast on the cost of congestion. The low load forecast was developed by adjusting downward the annual growth rates for each NYCA zone in the Base load forecast. These lower growth rates reflect slower economic growth than that embedded in the Gold Book forecasts over the study period. In this scenario NYCA energy was forecasted to decline at 0.16% annually (vs. a decline of 0.03% annually over the Study Period in the Base Case). This resulted in the annual NYCA energy forecast in 2026 being 5TWh (or 3.3%) below the Base forecast. The forecasted growth rates by NYCA Load Zone for the Lower load forecast are presented in Appendix J.

Scenario 3: Higher Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be higher than the base case. In this scenario, the NYISO utilized the high-range forecast provided by the USEIA in its 2017 Annual Energy Outlook. Consequently, as compared to the base case, the high natural gas price case uses prices approximately 28.5% higher for the NYCA.

Scenario 4: Lower Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be lower than the base case. In this scenario, the NYISO utilized the low-range forecast provided by the USEIA in its 2017 Annual Energy Outlook. Consequently, as compared to the base case, the low natural gas price case uses prices around 12% lower for the NYCA.

Scenario 5: National CO_2 Program

This scenario captures the potential impact of CO_2 emission allowance costs being incorporated in the production costs of generation located in non-RGGI states (e.g., Pennsylvania, New Jersey) in 2026.

Scenario 6: Public Policy (System Resource Shift/Western and AC Transmission Upgrades)

This scenario layers the Western and AC Public Policy transmission projects on top of the SRS case. It incorporates the Western transmission project selected by the NYISO Board; and generic model changes to reflect the AC Public Policy, *i.e.,* an increase in the Central East voltage limit of 350 MW and the relaxation of the UPNY-SENY interface.

Scenario 7: System Resource Shift

This scenario provides a comparison point for Scenario 6 (Public Policy). It includes each of the elements modeled in the ten-year SRS case as described in the "System Resource Shift-Model Assumptions" section above, i.e., a resource build-out representative of the Clean Energy Standard attainment, large-scale energy efficiency, and the retirement of New York coal units and the Indian Point Energy Center.

Figure 64 presents the impact of six scenarios selected for study. Those impacts are expressed as the change in congestion costs between the BAU baseline case and the scenario case.

Figure 64: Comparison of BAU Baseline Case and Scenario Cases, 2026 (nominal $M)

Demand Congestion ($M)	High Load	Low Load	High Natural Gas	Low Natural Gas	National CO_2	Public Policy (SRS / Transmission)
CENTRAL EAST	(31)	31	350	(95)	(57)	299
DUNWOODIE TO LONG ISLAND	19	(6)	29	(15)	(10)	(34)
LEEDS PLEASANT VALLEY	1	1	1	(0)	(0)	(4)
GREENWOOD	42	(13)	17	(7)	(8)	(7)
PACKARD HUNTLEY	4	(7)	(8)	1	15	(15)
EGRDNCTY 138 VALLYSTR 138 1	(3)	(2)	15	(5)	(2)	(5)
NIAGARA PACKARD	4	(1)	1	(0)	1	(1)
DUNWOODIE MOTTHAVEN	0	(2)	(0)	(0)	0	(2)
NEW SCOTLAND LEEDS	0	0	0	0	0	2
SHORE_RD 345 SHORE_RD 138 1	0	0	0	0	0	0
EDIC MARCY	2	(1)	(0)	2	2	(1)
RAINEY VERNON	1	(1)	1	(0)	(0)	(0)
CE-EM	(29)	30	350	(93)	(56)	299
CE-NSL-PV	(30)	31	351	(95)	(58)	297

Figure 65 below presents a summary of how each of the three transmission groupings chosen for study is affected by each of the scenarios for 2026. Figure 66 presents the percentage impact on Demand$ Congestion for each of the scenarios for each of the constraints. As shown, among the scenarios studied, the level of natural gas prices continues to be positively correlated with congestion as this directly drives the level of price separation between Downstate and Upstate New York. Congestion in the System Resource Shift case materially increases as significant additions of low-cost resources upstream exacerbate the price differential. This increase is offset by over 60% when Western and AC Public Policy transmission projects are modeled as in-service.

Figure 65: Impact on Demand$ Congestion ($2017M)

Constraints	Scenarios: Change in 2026 Demand$ Congestion from Base Case ($2017M)						
	High Load Forecast	Low Load Forecast	High Natural Gas Prices	Low Natural Gas Prices	National CO_2 Program	System Resource Shift Case	Public Policy (SRS / Transmission)
Central East-Edic-Marcy	(16)	17	197	(53)	(31)	424	168
Central East	(17)	17	197	(54)	(32)	425	169
Central East-New Scotland-Pleasant Valley	(17)	18	197	(54)	(32)	451	167

Figure 66: Impact on Demand$ Congestion (%)

Constraints	Scenarios: Change in 2026 Demand$ Congestion from Base Case (%)						
	High Load Forecast	Low Load Forecast	High Natural Gas Prices	Low Natural Gas Prices	National CO_2 Program	System Resource Shift Case	Public Policy (SRS / Transmission)
Central East-Edic-Marcy	-13%	14%	161%	-43%	-25%	348%	138%
Central East	-14%	14%	163%	-45%	-26%	351%	140%
Central East-New Scotland-Pleasant Valley	-14%	15%	159%	-44%	-26%	364%	135%

Figure 67 through Figure 69 show the congestion impact results of the six scenarios performed (as well as the 2026 results for the SRS case for comparison purposes with the Public Policy scenario). While the figure above shows the congestion impact from the scenarios for each of the most congested constraints, the figures below separately show how each of the three transmission groupings chosen for study are affected by each of the scenarios. In each case the bars represent the change in Demand$ Congestion between the Study 1 Base Case and the Scenario case.

Figure 67: Scenario Impact on Central East-Edic-Marcy Congestion

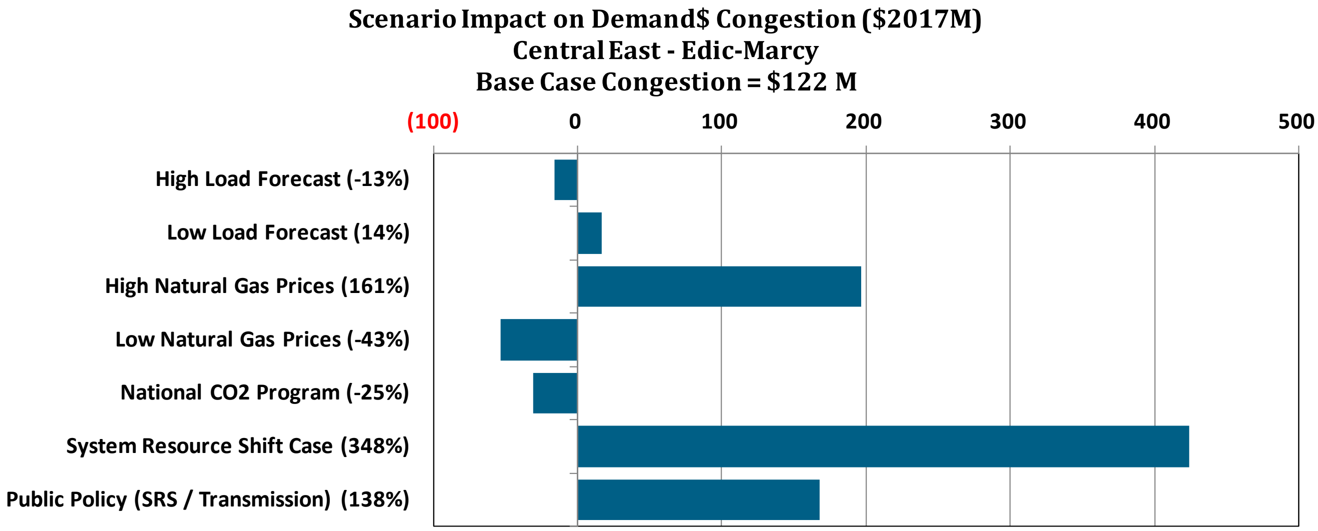


Figure 68: Scenario Impact on Central East Congestion

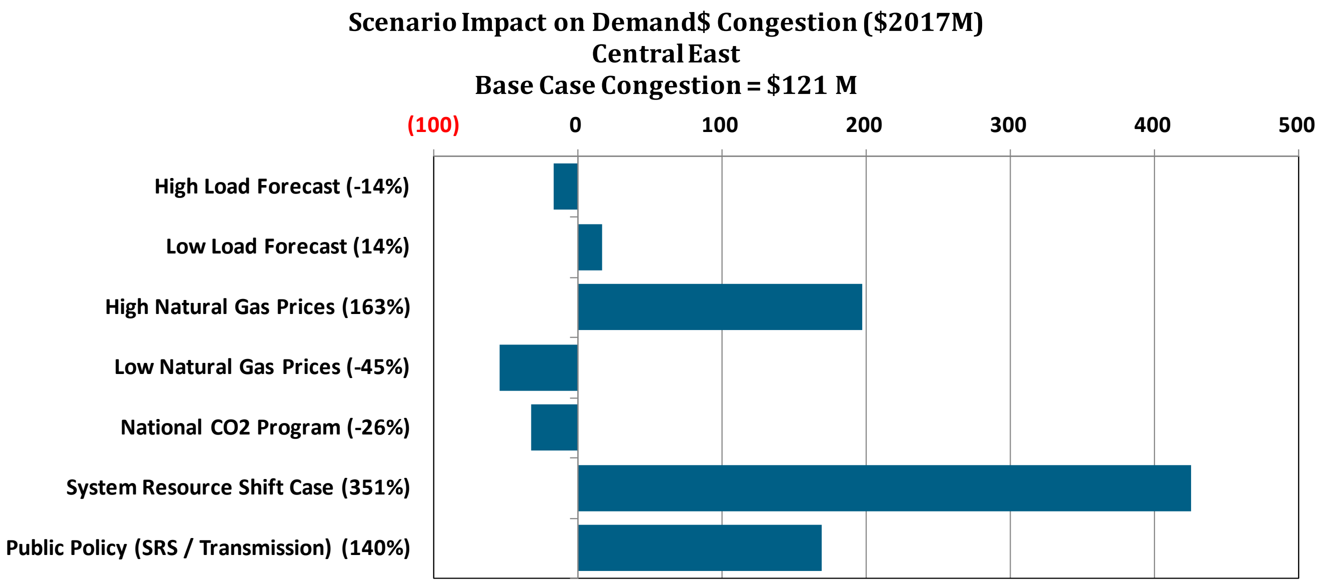
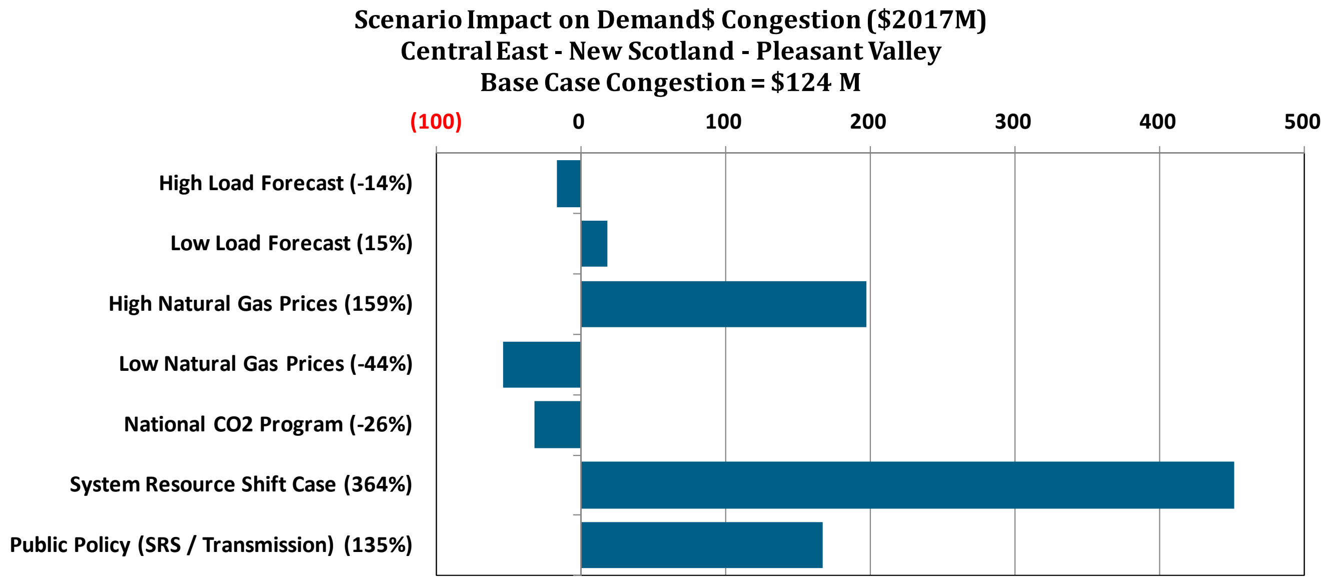


Figure 69: Scenario Impact on Central East-New Scotland-Pleasant Valley Congestion



2017 CARIS Findings – Study Phase

The CARIS identified three study areas by considering both historic and forecasted congestion patterns in the NYCA. The NYISO identified those monitored elements that have historically displayed high levels of congestion. It then utilized the GE-MAPS production cost model to identify those elements that would experience congestion through the 2017-2026 Study Period and identified the Central East through Leeds – Pleasant Valley corridors again as the most constrained areas of the NYCA system. In order to estimate the economic impact of alleviating the identified congestion, four generic solutions were applied to each of the three study areas, production costs savings were estimated, and B/C ratios were calculated based on a range of generic costs. In order to maximize the value of this study, three additional studies (for a total of six) were performed, examining congestion patterns and the impact of generic solutions with alternative base cases.

Figure 70 shows the projected congestion for each of the six studies.

Figure 70: Base Case Projected Congestion 2017-2026

Study	Ten-Year Demand$ Congestion	
	Nominal ($M)	Present Value ($2017M)
Study 1: Central East-Edic-Marcy	2,601	2,023
Study 2: Central East	2,540	1,966
Study 3: Central East-New Scotland-Pleasant Valley	2,563	1,983
Study 4: Study 3 with Edic-Marcy relaxed	3,371	2,596
Study 5: Study 3 under System Resource Shift Case	4,725	3,384
Study 6: Study 5 with Edic-Marcy relaxed	5,715	4,130

The application of the generic solutions in all six studies result in production cost savings expressed in 2017 present values, as shown in Figure 71.

Figure 71: Production Cost Savings 2017-2026 ($2017M)

Study	Ten-Year Production Cost Savings ($2017M)			
	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Study 1: Central East-Edic-Marcy	149	84	27	845
Study 2: Central East	124	84	27	845
Study 3: Central East-New Scotland-Pleasant Valley	185	152	55	1,696
Study 4: Study 3 with Edic-Marcy relaxed	197	159	54	1,728
Study 5: Study 3 under System Resource Shift Case	298	204	55	1,689
Study 6: Study 5 with Edic-Marcy relaxed	319	211	56	1,700

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 15% carrying cost charge, for transmission and generation solutions, to determine a benefit/cost ratio, as presented in Figure 72. A Capital Recovery Factor is not applied to demand response or energy efficiency solutions. See Appendix E for a detailed explanation.

Figure 72: Benefit/Cost Ratios

Study	Solution	Cost Category		
		Low	Mid	High
Study 1: Central East-Edic-Marcy	Transmission	0.46	0.32	0.25
	Generation	0.09	0.07	0.06
	Demand Response	0.11	0.08	0.07
	Energy Efficiency	0.77	0.70	0.64
Study 2: Central East	Transmission	0.38	0.27	0.21
	Generation	0.09	0.07	0.06
	Demand Response	0.11	0.08	0.07
	Energy Efficiency	0.77	0.70	0.64
Study 3: Central East-New Scotland-Pleasant Valley	Transmission	0.32	0.23	0.17
	Generation	0.08	0.06	0.05
	Demand Response	0.07	0.06	0.04
	Energy Efficiency	0.65	0.59	0.54
Study 4: Study 3 with Edic-Marcy relaxed	Transmission	0.34	0.24	0.19
	Generation	0.08	0.06	0.05
	Demand Response	0.07	0.06	0.04
	Energy Efficiency	0.66	0.60	0.55
Study 5: Study 3 under System Resource Shift Case	Transmission	0.52	0.36	0.28
	Generation	0.10	0.08	0.06
	Demand Response	0.07	0.06	0.04
	Energy Efficiency	0.65	0.59	0.54
Study 6: Study 5 with Edic-Marcy relaxed	Transmission	0.56	0.39	0.30
	Generation	0.11	0.08	0.06
	Demand Response	0.08	0.06	0.05
	Energy Efficiency	0.65	0.59	0.54

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 $27M to $1,700M resulting from the application of various generic transmission, generation, energy efficiency and demand response solutions; and (c) the Benefit/Cost ratios as low as 0.04 to as high as 0.77 depending on the high-medium-low generic project cost estimates. For each of the studies, none of the solutions produced a B/C ratio greater than one in each of the cost estimate categories, reflecting the fact that their projected costs outweighed their estimated production cost savings over the Study Period.

As noted, the benefits captured in the B/C ratios are limited to production cost savings. Other potential quantitative benefits, such as lower capacity market costs and enhanced system reliability, and qualitative impacts, such as the furtherance of public policy objectives, are not considered.

Key Findings

In conclusion, the study presents a series of metrics for a wide-range of potential futures and scenarios. One set of results can be viewed as a "business as usual" case, incorporating incremental resource changes based on the NYISO's study inclusion rules. These results, while informative to a degree, are borne of a resource rich landscape with limited load growth, and mirror past studies in identifying limited opportunities for transmission build-out based solely on production-cost reductions. A second set of results[34] is more forward-looking and captures impacts of global changes on the New York electric system that are exemplified by the achievement of New York's Clean Energy Standard through large-scale growth in renewable resources and implementation of energy-efficiency programs. It is these second set of results which provides the greater value in understanding future system congestion and the associated opportunities for economic investment in solutions.

The following should be considered as key takeaways:

- The results for the "business as usual" are consistent with those in prior CARIS studies in which the solutions studied offered a measure of congestion relief and production costs savings, but did not result in transmission projects with B/C ratios in excess of 1.0.
- The Central East-Pleasant Valley Transmission Solution, however, produced significantly higher production costs and demand congestion savings when studied with a resource mix driven by the Clean Energy Standard. Production costs reductions were 61% higher; and Demand$ Congestion savings 79% higher. This additional transfer capability across Central East and UPNY-SENY did materially increase the access of Upstate renewable resources to the downstream markets.
- The importance of the interplay between the CES and transmission expansion is indicated as well by the results of the SRS case and Public Policy scenario analyses for 2026. Congestion for the SRS case (of which the CES is a prime component) across the Central East-New Scotland-Pleasant Valley corridor is approximately $450M higher in 2026 than the base system ($124M vs. $574M) as renewable resources are bottled Upstate. Spillage for solar and wind resources – the curtailment of renewable generation due to transmission constraints – is nearly non-existent in the 2026 BAU case but increases to 1.2 TWh in the SRS case. As expected, the output from NY renewable resources in the SRS case increase dramatically from the BAU case (nearly

34 This second set of results is presented as the System Resource Shift case.

28 TWh in 2026)[35]. There was, however, a reduction of 0.7 TWh in nuclear output from the BAU case to the SRS case.[36] Finally, net imports from PJM, IESO and ISO-NE decrease in the SRS case (from the BAU) case by 14 TWh, as New York exports a portion of the increased renewable energy to its neighbors.

- The build-out of the Western and AC Transmission projects has a significant impact on how the SRS case affects a number of key metrics. It reduces the higher congestion observed in the SRS case in the Central East-New Scotland-Pleasant Valley corridor by $284M. The additional transmission in the Public Policy scenario increases the renewable energy production by an incremental 0.5 TWh from the SRS case; and the output from upstate nuclear units by 0.4 TWh. This scenario also resulted in a reduction of 1.6 TWh in output from gas-fired generation located in Zones F – K. Finally, overall net imports increase by less than 0.3 TWh (as exports decrease) between the SRS case and the Public Policy scenario.
- The spillage of renewable solar and wind resources in the SRS case and Public Policy Scenario is due to constraints on the bulk-power system and is not reflective of transmission limitations present on the lower-voltage system (e.g., the 115 kV system in upstate zones). The spillage identified can therefore be considered a lower bound and would only be exacerbated should the lower voltage system be monitored and secured in the commitment and dispatch processes.

35 Production from those renewable resources added in the SRS case displaced 257 GWh of production from existing wind resources; 68 GWh from solar units; and 2 GWh from hydroelectric units.

36 In the context of this study, the reduced output from nuclear units can be viewed as a proxy for lower output from renewable resources resulting from curtailment of either existing or new renewable resources. The NYISO is exploring alternative modeling constructs for fixed units and hourly modifiers that would make this trade-off more explicit in future studies.

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.

Additional CARIS Studies

In addition to the reported 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.

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 of Directors. The model for Phase 2 studies would include known changes to the system configuration that meet base case inclusion rules and would be updated with any new load forecasts, fuel costs, and emission costs projections upon review and discussion by stakeholders. 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.[37] To qualify, the total capital cost of the project must exceed $25 million, the benefits as measured by the NYCA-wide production cost savings must exceed the project cost measured over the first ten years from the proposed commercial operation date, and a super-majority (> 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 the Economic Planning Manual.[38]

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.

37 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.

38 http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/epp_caris_mnl.pdf

The next CARIS cycle is scheduled to begin in 2019.

Appendix A – Glossary

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.

Comprehensive Reliability Plan (CRP): A biennial 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.

Comprehensive System Planning Process (CSPP): The Comprehensive System Planning Process encompasses reliability planning, economic planning, Public Policy Requirements planning, cost allocation and cost recovery, and interregional planning coordination.

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 System Planning Process (CSPP), 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]

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 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 11,009-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.

Public Policy Transmission Planning Process (PPTPP): The process by which the ISO solicits needs for transmission driven by Public Policy Requirements, evaluates all solutions on a comparable basis, and selects the more efficient or cost effective transmission solution, if any, for eligibility for cost allocation under the ISO Tariffs.

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 Demand Response. 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): A biennial 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 one of the three primary planning processes in the NYISO's CSPP.

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.

NEW YORK INDEPENDENT SYSTEM OPERATOR

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