Appendix D

EXHIBIT NO. NYT-4

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

New York Transco, LLC	)	
	)	
Central Hudson Gas & Electric Corp.	)	
Consolidated Edison Company of	)	
New York, Inc.	)	**Docket No. ER15-___-000**
Niagara Mohawk Power Corporation d/b/a	)	
National Grid	)	
New York State Electric & Gas Corp.	)	
Orange & Rockland Utilities, Inc.	)	
Rochester Gas and Electric Corp.	)	

**PREPARED DIRECT TESTIMONY
OF PAUL E. HAERING AND RICHARD W. ALLEN
ON BEHALF OF THE NEW YORK TRANSCO, LLC**

December 4, 2014

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ON BEHALF OF THE NEW YORK TRANSCO, LLC

Q. Mr. Haering, please state your name and business address.

A. My name is Paul E. Haering, and my business address is 284 South Avenue, Poughkeepsie, NY 12601.

Q. By whom are you employed and in what capacity?

A. I am Vice President of Engineering and Operations Services at Central Hudson Gas and Electric Corporation ("Central Hudson"), a Fortis Company. In that capacity I am responsible for the engineering planning and design for Central Hudson's gas and electric transmission and distribution systems. I am responsible for the construction, operation, and maintenance of our electrical substations. In addition, I have responsibility for our Operations Services organization. In my role I am responsible for overseeing the development of the Company's capital forecasts and also Chair of the Company's Capital Asset Review and Evaluation

Committee which oversees the implementation of the annual capital program. I have had these responsibilities since 2007.

Q. Please summarize your educational background.

A. I graduated from Manhattan College in 1986 with a Bachelor of Engineering in Electrical Engineering degree. In 1992, I received a Masters of Electrical Engineering degree from Polytechnic University. In 2007, I received a Master of Business Administration from Rensselaer Polytechnic Institute.

Q. Please summarize your professional experience.

A. I joined Central Hudson in 1986 as a Junior Engineer in the Substation Design Section. In 1989 I was transferred to work as a staff engineer in the Operations Services Division, which has responsibility for the operation, maintenance, and construction of the Company's substation facilities. In 1994, I was promoted to the position of Operations Supervisor in the Operations Services Division. In 2000, I was transferred to the position of Engineer in the Electric System Protection Section. In 2001, I became Section Engineer for the Distribution Engineering Section. In 2003, I was promoted to the position of Manager of Electric Transmission and Distribution. In 2004, I was promoted to the position of Manager of Electric Engineering Services. In May of 2007, I was named the Assistant Vice President of Engineering and Environmental Services and in December 2007 named to my current position.

Q. Have you previously testified before this Commission?

A. No.

Q. Mr. Allen, please state your name and business address.

A. My name is Richard W. Allen, and my business address is 1125 Broadway, Albany, NY 12204.

Q. By whom are you employed and in what capacity?

A. I am Director of Business Development for National Grid whose US headquarters are located in Waltham, Massachusetts. In that capacity I am responsible for identifying, analyzing, and recommending business growth opportunities in the United States with focus in New York and the mid-Atlantic region. These opportunities may include joint ventures to develop large project proposals or assessing potential target companies or assets for acquisition. I am also responsible for implementing those recommendations the corporation has approved. I have had these responsibilities since December 2009.

Q. Please summarize your educational background.

A. I graduated from Clarkson University in 1987 with a Bachelor of Science in Electrical Engineering. In 1989, I received a Masters of Electrical Engineering degree from Rensselaer Polytechnic Institute. In 2004, I received a Master of Business Administration from Rensselaer Polytechnic Institute. I am a Certified Project Management Professional with the Project Management Institute.

Q. Please summarize your professional experience.

A. In 1991, I joined Niagara Mohawk Power Corporation (now National Grid) as a substation design engineer and project manager where I designed new high voltage substations and capital improvements to existing substations, managing the permitting, construction and commissioning of substation projects in a challenging regulatory environment. In 1995, I was promoted to the position of

Power Delivery Supervisor responsible for the construction, operation, and maintenance of high voltage electric substations. In 1999, I assumed the position of Relay Supervisor responsible for the installation, operation, and maintenance of the electric system protection and controls as well as the testing and commissioning of major electric power equipment and facilities. In 2003, I was transferred to the position of Senior Engineer in Transmission Planning, performing load flow analysis and congestion analysis. Power system planning software programs that I am trained to use includes PSS/E and GE MAPS. In March of 2005, I was promoted to the position of Lead Project Manager where I managed major infrastructure improvement projects including power plant interconnections, new transmission lines and substations. In December of 2009, I was promoted to my current position.

Q. Have you previously testified before this Commission?

A. No.

Q. Mr. Haering and Mr. Allen, on whose behalf are you testifying?

A. We are testifying on behalf of New York Transco LLC (“NY Transco”).

Q. What is the purpose of your testimony in this proceeding?

A. As Mr. Nachmias explains, the NY Transco will develop, construct and own five new high voltage transmission projects that will relieve long-standing transmission constraints, improve grid reliability (including with respect to the potential retirement of large generating plants in southeastern New York), facilitate the integration of renewable energy generators, support economic growth in the State, and address other State public policy needs. The purpose of our testimony will be to describe these projects in greater detail, and to explain the risks and challenges that NY Transco faces in completing the five projects. In addition, we will describe the benefits of these projects.

As background, we will describe the major concerns that we see with New York's existing power grid and some of the studies that have documented the basis for those concerns. We will also describe the proceedings conducted by the New York Public Service Commission ("NYPSC") in which it found that three of the five transmission projects are needed to relieve transmission congestion and to provide long-term service reliability, and we will explain that the NYPSC is also examining the congestion, reliability, and other benefits associated with NY Transco's other two projects in a related proceeding. We will describe the process going forward to complete these projects, our efforts to control costs, and the difficulties that we face in completing them by the required service dates.

Q. Are you sponsoring any exhibits?

A. Yes. We are sponsoring Exhibit Nos. NYT-5 – NYT-17.

Q. Please summarize your concerns with the condition of New York's transmission grid.

A. New York's transmission grid is aging and constraints on the grid make the network less efficient, causing energy and capacity prices to be higher than they would be with more transmission that would allow increased flows of energy across the state. Ultimately, the age and inefficiency of the grid has reliability implications. This is especially challenging in an unregulated market when generating plants can retire on short notice, and it becomes more and more difficult and expensive to deliver power to customers. The concerns regarding aging infrastructure and the current market's inability to address the long standing grid congestion and reliability issues are illustrated by the fact that the last new major transmission line across the major statewide interfaces rated at 345 kV or above constructed in New York was the Marcy South transmission line, which was built over 30 years ago. According to the comprehensive State Transmission Assessment and Reliability Study, or STARS analysis, began in 2008, approximately 4,700 of the State's 11,000 miles of high voltage transmission lines may need to be replaced in the next 30 years.[1] Moreover, choke points on transmission lines between upstate New York and the southeast part of the State result in the NYISO dispatching more expensive generation than it otherwise would, thereby causing "congestion costs" between $765 million[2] and $1.1 billion in recent years.[3]

These transmission constraints also restrict the deliverability of generating capacity to meet New York Control Area reliability criteria, which require the system to be planned so that consumers can expect a major service outage no more than one day in ten years (a probability of 0.1 days per year). As the NYPSC found, if the 2,040 MW Indian Point Energy Center ("IPEC") near New York City retires at the end of 2015, the probability of lost load will be almost five times the allowed limit (0.48 days/year).[4]

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[1] A copy of the STARS report is attached as Exhibit No. NYT-5.

[2] NYISO 2013 Congestion Assessment and Resource Integration Studies Report at pp. 15-16 (attached as Exhibit No. NYT-6). This report presented total congestion costs for 2012.

[3] NYISO 2011 Congestion Assessment and Resource Integration Study Report at p. 43 (available at http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/Caris_Final_Reports/2011_CARIS_Final_Report__3-20-12.pdf). This report presented total congestion costs for 2010.

[4] Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans, New York Public Service Commission, Case 12-E-0503, *Order Accepting IPEC Reliability Contingency*

The question of whether or not IPEC will continue to operate beyond 2015 amplifies the reliability concerns that can arise when large generating plants retire on short notice. In addition to IPEC, the approximately 500 MW Danskammer generating plant in the lower Hudson Valley was set to be decommissioned in 2014 until the plant's owner signed a four-year capacity sales contract with Central Hudson. The return of the Danskammer plant to operation was approved by the NYPSC in the summer of 2014. Danskammer's future is uncertain beyond the four-year capacity contract term. The potential for generating plants to mothball or retire on short notice can lead to reliability problems both on a local and bulk system level and because transmission projects have long lead times, they are typically not a viable option to address these reliability concerns caused by unit retirements unless they are planned well in advance. Such impacts also affect upstate communities where the plants operate, impacting tax revenue to local towns and municipalities, as well as potential loss of jobs at those plants.

Q. Have there been any studies to evaluate the condition of New York's power grid?

A. The STARS analysis was the first major study performed in the past decade to look beyond the NYISO's planning processes. In an effort to proactively address the looming issues of congestion, infrastructure replacement, and the continued reliable operation of the electric system, the NYTOs initiated a statewide transmission planning study in 2008. The purpose was to look beyond the NYISO's planning studies that are limited to identifying transmission projects that will be needed to prevent violations of North American Electric Reliability

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Plans, Establishing Cost Allocation and Recovery, and Denying Requests for Rehearing (issued Nov. 4, 2013) at p. 19 ("Reliability Contingency Plan Order") (attached as Exhibit No. NYT-7).

Corporation reliability criteria. The NYTOs funded the study, and conducted it with technical support from the NYISO and consultant ABB.

Q. How was the STARS study structured?

A. The STARS Technical Working Group divided the study into two phases:

PHASE I: This portion of the study evaluated several generation expansion scenarios and the ability of the existing transmission system to meet statewide loss of load expectation criteria of no more than one day in ten years (0.1 days/year) over a 20 year horizon period. A statewide generation expansion scenario was utilized as the base case for phase II of the study.

PHASE II: Identify the most suitable, cost effective transmission alternatives to provide additional transfer capability and improve system reliability consistent with upgrading aged infrastructure and integrating new renewable generating resources.

Q. What did the STARS study find?

A. The study began with an initial "condition assessment" of New York's high voltage power grid and identified about 4,700 miles of transmission lines that will reach the end of their useful service lives within the next 30 years and may require replacement, which is about 40 percent of the entire grid. More pressing, however, the study identified the need to address key transmission constraints on the power grid that impair efficiency and long term reliability. The study identified constraints on the UPNY/SENY and Central East corridors near Albany as the most stressed areas of the grid.

Q. What are the UPNY/SENY and Central East corridors?

A. They are two important transmission corridors. Generally speaking, the first corridor is located between Albany and the lower Hudson Valley through which the UPNY/SENY interface passes. This interface consists of multiple 345 kV transmission lines with the most constraining transmission lines connecting (1) the Leeds Substation with the Pleasant Valley Substation, (2) the Leeds Substation with the Hurley Avenue Substation, and (3) the Coopers Corners Substation with the Rock Tavern Substation.

The second corridor is located between Utica and Albany. This is the Central East interface. This interface also consists of multiple 345 kV and 230 kV transmission lines with the most constraining transmission lines connecting (1) the Edic Substation with the New Scotland Substation, and (2) the Porter Substation with the Rotterdam Substation.

Q. Did the STARS report identify solutions to these corridors?

A. Yes. The STARS report identified three projects for immediate action because they were judged most likely to produce near-term economic and long-term reliability benefits to consumers. These projects are: (1) a third Leeds-Pleasant Valley 345 kV line, (2) a third New Scotland-Leeds 345 kV line, and (3) a second Ramapo-to-Rock Tavern 345 kV line. The report identified two additional projects for further study for long term system reliability given the potential retirement of IPEC: (1) Marcy South Series Compensation and (2) the Staten Island Generation Un-bottling project (a project to make generators on Staten Island accessible to the grid). Finally, the report recommended upgrades to three major 345 kV transmission lines: (1) Moses-to-Marcy, (2) Marcy-to-New Scotland, and (3) Oakdale-to-Fraser.

Several of these projects evolved into NY Transco's initial group of five transmission expansion projects that are the subject of this filing, as we will explain later.

Q. Can you quantify the significance of these transmission corridor constraints?

A. The NYISO's 2014 Reliability Needs Assessment initially found a need for 1,150 MW of transmission transfer capability or new generation in southwestern New York by 2024 to offset the constraints.[5] The NYISO found this need even with the TOTS projects included in its base case.[6] In a recent FERC proceeding in Docket No. ER13-1380-000 concerning the formation of a new capacity pricing zone in the lower Hudson Valley, NYISO showed that slightly more than 800 MW of generating capacity in western New York is "bottled up" due to UPNY/SENY and thus not available to be counted on to meet the generating resource adequacy needs of consumers in southeastern New York.[7] FERC relied on that fact to justify creating the capacity pricing zone to send price signals to build new generation or transmission facilities.[8] These higher capacity prices will

[5] New York Independent System Operator, 2014 Reliability Needs Assessment, Final Report (Sept. 16, 2014) at pp. iii and 34 ("NYISO 2014 RNA") (attached as Exhibit No. NYT-10).

[6] *Id*. at pp. 14, 29.

[7] *New York Indep. Sys. Operator, Inc.*, Proposed Tariff Revisions to Establish and Recognize a New Capacity Zone and Request for Action on Pending Compliance Filing, Docket No. ER13-1380-000 (filed Apr. 30, 2013), Att. XIII, Affidavit of Steven L. Corey at p. 8 (stating that NYISO's study had found 849.2 MW of capacity in western New York is precluded by the UPNY/SENY constraint from reaching consumers in southeastern New York under all transmission conditions) [hereinafter "NYISO NCZ Filing"].

[8] *New York Indep. Sys. Operator, Inc.*, 144 FERC ¶ 61,126, at PP 14 & 21 (2013).

cost ratepayers hundreds of millions of dollars and are the subject of great controversy.[9]

Q. What has FERC said about the UPNY/SENY and Central East corridors?

A. The Commission found that the UPNY/SENY and Central East corridors are causing current congestion and longer term reliability impacts that require immediate attention.[10] In particular, to quote from the recent capacity zone order:

> The Commission relied on NYISO's conclusion from its deliverability tests (beginning in 2008) that the UPNY/SENY transmission interface between the Upper Hudson Valley and the Lower Hudson Valley has been ***overloaded*** since 2008. Additionally, NYISO's market monitor had identified ***long-term reliability concerns*** in the Lower Hudson Valley that could be addressed by the creation of the new capacity zone.[11]

The Commission went on to cite the NYISO Market Monitor's reports on the effect that UPNY/SENY has on reliability, explaining:

> The 2012 State of the Market Report described the effects of not having a separate capacity zone stating that the total amount of unforced capacity sold in Zones G, H, and I had fallen by 1 GW (or 21 percent) since the summer of 2006. This fact demonstrates the precise concerns of the Commission and an underlying reason that NYISO's tariff requires the creation of a new capacity zone when capacity resources are not deliverable throughout a zone **–** ***reliability***.[12]

To underscore the urgency of the problem, the Commission found the situation had already become critical going into the Summer of 2014:

> NYISO's 2014 Summer Capacity Assessment states that there will be a 1,431 MW capacity reserve shortage during the upcoming summer in Southeast New York under extreme weather conditions, in part due to the constrained UPNY/SENY transmission constraint.[13]

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9 NYISO NCZ Filing, Att. XII, Affidavit of Tariq N. Niazi, at Table 3. NYISO initially forecast a capacity price increase for southeastern New York of about $180 million a year, or $540 million for the three-year period until the next reexamination of NYISO's capacity zone pricing method.

10 *New York Indep. Sys. Operator, Inc.*, 147 FERC ¶ 61,152, at PP 13-16 (2014).

11 *Id*. at P 13 (emphasis added).

12 *Id*. at P 16 (emphasis added).

13 *Id.* at n.29.

In short, FERC found that constraints on the UPNY/SENY and Central East interfaces are causing serious near- and long-term congestion and reliability concerns that are in need of an urgent response.

Q. What has New York been doing to address these transmission constraints?

A. Following the STARS report, New York's Governor through the Energy Highway Task Force issued a Request for Information ("RFI") seeking proposals to "modernize the transmission system and eliminate the bottlenecks" as Mr. Nachmias explains in his testimony.[14] The RFI resulted in 130 project proposals from 85 developers,[15] including 18 transmission projects proposed by the NYTOs based on the work in the STARS assessment.[16] The NYTO proposals included the second Ramapo-to-Rock Tavern 345 kV line, the combined Marcy South Series Compensation and the Fraser-to-Coopers Reconductoring project, a suite of projects that would construct a new 345 kV line between Edic and Pleasant Valley Substations, the Oakdale-to-Fraser 345 kV line, and the Staten Island Unbottling Project to relieve transmission constraints that prevent electricity generated on Staten Island from reaching the broader transmission grid.

Q. What did the Energy Highway Task Force do with the responses to the RFI?

A. The Task Force used the results of the RFI to help formulate a plan to address New York's future energy needs. They issued the *Energy Highway Blueprint* to

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[14] RFI at p. 6. The RFI is available at: http://nyenergyhighway.com.

[15] *Energy Highway Blueprint* at p. 14.

[16] According to the *Energy Highway Blueprint*, the 130 proposals submitted into the RFI represented more than 25,000 MW of potential new generation and transmission capacity. *Energy Highway Blueprint* at p. 27. At the time the NYTOs submitted the response to the State's request for proposals, NYPA and LIPA were participating in the NY Transco effort.

encourage projects to relieve the constraints on the Central East and UPNY/SENY interfaces.[17]

Q. Were there other issues identified on the Blueprint?

A. Yes. Another was to address the reliability risks to the transmission grid in the event that the Nuclear Regulatory Commission does not renew the license for IPEC by the end of 2015.[18] The uncertain future of IPEC adds a significant reliability component to transmission upgrades to relieve Central East and UPNY/SENY congestion because "these are also expected to significantly reduce the need for new power plant capacity to meet reliability needs."[19]

Q. What happened next?

A. The NYPSC initiated proceedings as recommended by the Task Force to identify and select projects to solve the State's needs to improve reliability, reduce energy costs, meet various policy goals, including the development of more renewable energy, and to support long-term economic growth.

The NYPSC began two proceedings. One is called the "Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans"[20] to address reliability concerns raised by the potential retirement of IPEC. This is sometimes called the "Reliability Contingency Plan Proceeding."

The second was the "Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades"[21] which was initiated to upgrade the Central East and UPNY/SENY corridors by 1,000 MW with new

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[17] *Id*. at pp. 40-41.
[18] *Id*. at pp. 48-49.
[19] *Id*. at p. 49.
[20] NYPSC Case 12-E-0503.
[21] NYPSC Case 12-T-0502.

alternating current transmission upgrades in order to increase the transmission transfer capability, decrease congestion, and provide enhanced system reliability. This proceeding is sometimes called the "AC Proceeding." Mr. Nachmias provides more information about the status of these proceedings.

Q. What concerns did the NYPSC address in the Reliability Contingency Plan Proceeding?

A. The NYPSC focused on the reliability needs that must be addressed by the start of the peak summer demand season on June 1, 2016, in the event that IPEC is retired at the end of 2015. As we mentioned, the NYPSC found that the retirement of IPEC creates an unacceptably high loss of load probability of 0.48 days per year—a significant violation of the maximum 0.1 days per year reliability criterion that must be met for planning purposes in the New York Control Area. Relying in part on NYISO's RNA analysis in 2012 which showed an anticipated generation deficiency of approximately 1,000 MW in southeastern New York if IPEC retires,[22] the NYPSC took note of the fact that NYISO's tariff does not allow it to include the retirement of a generating plant in its transmission planning process until the owner formally notifies NYISO that it plans to retire the facility. The NYPSC found that waiting for IPEC's owner to notify NYISO that the plant will retire would leave insufficient time to address the resulting reliability needs and place consumers at risk.

Q. Did the NYTOs propose any transmission projects in the Reliability Contingency Plan Proceeding?

A. Yes. In the Reliability Contingency Plan Proceeding, the NYPSC directed Consolidated Edison Company of New York, Inc. ("Con Edison") and the New

22 Reliability Contingency Plan Order at pp. 18-19.

York Power Authority ("NYPA") to work with NYPSC staff to develop and present a contingency plan to relieve reliability concerns that would arise if the IPEC facility is unable to obtain a new operating license from the Nuclear Regulatory Commission by the end of 2015. On February 1, 2013, Con Edison and NYPA presented their plan, as directed. The plan proposed three transmission projects, referred to as the Transmission Owner Transmission Solutions ("TOTS") previously identified through the STARS studies as necessary to address near-term reliability concerns, and also proposed that NYPA solicit generation and transmission solutions through a "request for proposals" ("RFP") process. NYPA subsequently conducted the RFP, and the NYPSC considered the proposed TOTS projects and the projects proposed through the RFP in further proceedings.

Q. Please describe the transmission projects that New York Transco presented to the NYPSC.

A. The three TOTS projects proposed in the Reliability Contingency Plan Proceeding are: (1) a second Ramapo to Rock Tavern 345 kV Line (the "RRT Project"), (2) the creation of a 2nd 345 kV feeder interconnecting the Goethals Substation on Staten Island and Linden Substation in New Jersey, plus the addition of forced cooling on four existing 345 kV feeders to allow generating facilities on Staten Island to support additional energy flows to the New York grid (the "Staten Island Unbottling Project"), and (3) a project to add series compensation on the Marcy-to-Coopers Corners transmission path and the Reconductoring of the approximately 21.8-mile Fraser-to-Coopers Corners 345 kV transmission line (the "MSSC Project").

A detailed description of each project as presented to the NYPSC is attached as Exhibit Nos. NYT-11 (RRT Project), NYT-12 (Staten Island Unbottling Project), and NYT-13 (MSSC Project).

Q. Did the NYPSC make any findings about these projects?

A. Yes. The NYPSC found that the TOTS projects will provide 600 MW towards the reliability need created with the retirement of IPEC. Further, these projects will provide increased transfer capability, approximately 450 MW across UPNY/SENY, which would provide economic benefits by supplying lower cost energy from upstate sources to downstate consumers.[23] Specifically, the NYPSC found that the TOTS projects "contribute toward the potential reliability need, while offering net benefits for ratepayers even if IPEC were to operate beyond December 2015."[24]

Q. Did the NYPSC quantify the benefits of the TOTS projects?

A. Yes. The NYPSC stated that its Staff estimated that the TOTS projects will have "a net present value (NPV) of approximately $260 million in 2016 dollars. For the full 40 years of rate recovery, the NPV of <u>net</u> benefits was estimated to be approximately $670 million."[25]

Q. Has the NYISO made any findings about the TOTS projects?

A. Yes. The NYISO has included the TOTS projects in its comprehensive planning process, specifically including them in its RNA. NYISO found in its 2014 RNA

[23] *Id*. at pp. 23-25.
[24] *Id*. at p. 22.
[25] *Id.* at 24.

that the TOTS projects will improve transmission system reliability and relieve the UPNY/SENY and Central East Group constraints.[26] NYISO stated:

> The inclusion of the TOTS projects in the model also resulted in increases to the Central East Group, Marcy South, and UPNY-SENY MARS interface transfer limits. The TOTS projects that add series compensation to the Marcy South transmission corridor effectively increase flow through that transmission path. The second Rock Tavern-Ramapo 345 kV line also contributes to this change in the power flow pattern. The result is that power is diverted somewhat from the circuits that make up the Central East MARS interface and the power flow across the UPNY-SENY interface is more balanced between the Marcy South corridor and the Leeds-Pleasant Valley corridor. Inclusion of the TOTS projects also impacts the A line and VFT interface (Staten Island) by significantly reducing the constraints on flows from Staten Island generation and the ties to New Jersey.[27]

The NYISO estimated that the addition of the TOTS will increase UPNY/SENY transfer by at least 450 MW and that the impact of increased transmission transfer capability has the same effect as increasing downstream generation:

> [A]nalysis . . . showed that UPNY-SENY remains among the most constraining interfaces, consistent with the conclusion from the previous RNAs. This indicates that increasing the total resources downstream of UPNY-SENY or increasing the UPNY-SENY transfer limit will be among the most effective options to resolve the LOLE violations. . . . Increasing the limit on UPNY-SENY by 1,000 MW showed the most movement in [Statewide] LOLE and the individual Load Zone LOLE. Zonal LOLE went down for all Zones G-K.[28]

In summary, NYISO's findings show the TOTS projects increase transfer limits across UPNY/SENY by at least 450 MW, and thereby provide significant reliability benefits to the transmission network. Relieving the UPNY/SENY constraint will also improve both local and statewide reliability by reducing the

26 NYISO 2014 RNA at p. 28.
27 *Id*. at p. 29.
28 *Id.* at p. 31.

loss of load expectation and allowing greater access to generation in western New York to satisfy resource adequacy requirements.

Q. Has NYISO solicited transmission projects to address identified system needs?

A. Yes. On October 1, 2014, NYISO issued a request for transmission proposals. However, on November 14, 2014, NYISO withdrew its request, explaining that generating resource announcements issued since the 2014 RNA study base case was established, coupled with updates to the NYTO local transmission plans such as the TOTS Projects, have alleviated the need for more transmission projects.[29] However, NYISO explained that this need has been alleviated for only four years, at which time NYISO predicts the system will again require solutions to meet its system requirements.[30] In the meantime, if there are unforeseen generator retirements, NYISO will solicit proposals for "Gap" solutions. The NYISO's changing assessment of transmission needs based on short-term events—like old generating units that decide not to retire—highlights one of NY Transco's business risks. This also highlights the fact that in the current planning process in New York, transmission infrastructure is seen as a backstop solution, which is why it is important to have a planning process to address public policy goals like relieving congestion.

Q. Do you expect other benefits from the TOTS projects?

A. Yes. The NYISO's changing modeling assumptions or additions in generation below the constraints have not caused the underlying deficiencies in the

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[29] A copy of NYISO's letter is attached at Exhibit No. NYT-8.

[30] Mary Powers, *NYISO resource needs ease amid new plans*, Megawatt Daily, Nov. 25, 2014, at 11 (attached as Exhibit No. NYT-9).

transmission network to go away. The projects will allow the NYISO to use generating resources in the State more efficiently, which will lower statewide production costs. Relieving the UPNY/SENY and Central East constraints will also allow generating capacity in western New York to be deliverable into southeastern New York, thereby lowering capacity costs which recently increased by more than $200 million a year with the formation of a new capacity pricing zone in the lower Hudson Valley.

Beyond these benefits, according to The Brattle Group study prepared for the NYPSC in the Reliability Contingency Plan Proceeding, the TOTS projects are likely to provide significant benefits through:

- Reduced transmission energy losses;
- Reduced congestion due to transmission outages;
- Mitigation of extreme events and system contingencies;
- Reduced cost due to imperfect foresight of real-time system conditions;
- Reduced cost of cycling power plants;
- Reduced amounts and costs of operating reserves and other ancillary services; and
- Mitigation of reliability-must-run (RMR) conditions.[31]

While these benefits have not been quantified, they are nevertheless real benefits to customers. It is reasonable to expect that due to the scale of the AC Projects, these same benefits will accrue to them as well. Moreover, consistent with the

[31] Reliability Contingency Plan Order at pp. 23-25.

goal to address statewide public policies, in addition to the above noted benefits, additional benefits were identified including:

- Reduced emissions;
- Increased tax revenue;
- Increased employment; and
- Increased system resiliency and reliability.

Q. What are some of the risks of the TOTS projects?

A. While the TOTS projects have their state siting approvals, there are many other regulatory approvals, studies, and permits that are needed for each of these projects before actual construction can begin. Thus, while the projects have been selected by the state, there remain additional risks to completing the project and to doing so in a timely manner.

Q. Please explain.

A. There are a number of regulatory and governmental approvals, studies, and permits required to construct the TOTS projects. These approvals are discussed in detail in Exhibit No. NYT-14.

Q. What are some of the conditions that have been imposed by government agencies that affect the risks and challenges of building the TOTS projects?

A. The conditions and impact vary by project. For example, in its order approving Con Edison's Environmental Management and Construction Plan ("EM&CP") for the second Ramapo-to-Rock Tavern 345 kV line, the NYPSC imposed a number of conditions that may affect the costs, risks and challenges of building this project.[32]

The NYPSC stated that should culturally significant resources be encountered during construction, Con Edison must immediately cease construction in that area and notify NYPSC Staff and the New York State Office of Parks, Recreation and Historic Preservation Field Services Bureau.[33] Con Edison cannot proceed with construction until the significance of the resource has been evaluated and the need for any impact mitigation has been determined.[34] Con Edison must also comply with the applicable requirements of the Federal Water Pollution Control Act and the New York State water quality standards.[35] Furthermore, within 45 days after the commencement of operation of the Sugarloaf substation, Con Edison must file a report from an independent acoustical consultant measuring the noise produced by the substation.[36] If this noise survey and report reveals an increase in the ambient sound levels at any existing residential receptor or property line of 6 dBA or more, Con Edison must submit noise mitigation plans to the NYPSC and resubmit a post-mitigation noise survey demonstrating that these conditions have been resolved.[37] The NYPSC's conditions present additional challenges in building these projects, as construction may suddenly be halted should culturally significant resources be encountered or

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32 NYPSC Case 13-T-0586 – Petition of Consolidated Edison Company of New York, Inc. for Approval of Environmental Management and Construction Plan for Sugarloaf to Rock Tavern Segment of Second Ramapo to Rock Tavern 345 kV Transmission Line (Feeder 76), (issued Oct. 27, 2014) at pp. 14-20 (attached as Exhibit No. NYT-15).

33 *Id.* at 16-17.

34 *Id.* at 17.

35 *Id.* at 18.

36 *Id.* at 19.

37 *Id.* at 19-20.

noise levels exceed acceptable levels. These delays in construction may hinder the ability of the TOTS project to be in-service by the required June 1, 2016 date, or may result in changes that increase costs.

Q. What about the Fraser-Coopers Corners reconductoring project?

A. The Fraser – Cooper Corners reconductoring project requires Federal, State, and Local regulatory approvals and licenses. For one, a portion of the reconductoring work on the Fraser-Coopers Corners line will traverse New York's Catskill State Park. In connection with this work, an Application for Temporary Revocable Permit will be filed with the New York State Department of Environmental Conservation ("DEC"), which provides for the temporary use of state lands and conservation easement lands. The project will also require successful completion of an Environmental Assessment by the DEC under the State Environmental Quality Review Act ("SEQRA"). NYSEG has filed a SEQRA Full Environmental Assessment Form, and this process remains ongoing. In addition, construction of the project will also require: (1) authorization under the Nationwide Permit pursuant to Section 404 of the Clean Water Act from the U.S. Army Corps of Engineers; (2) Cultural Resources Clearance from the New York State Historic Preservation Office; (3) a Highway Work Permit from the New York State Department of Transportation; (4) approval of a Storm Water Pollution Prevention Plan by the New York City Department of Environmental Protection; (5) Delaware River Basin Commission review; (6) consultation with the U.S. Fish and Wildlife Services; (7) DEC State Pollution Discharge Elimination System general or individual permits under Article 15 and Article 24 of the Environmental Conservation Law; and (8) a special permit/site plan review from the Town of Delhi, New York for the series capacitor banks. Each of these permits presents risk to the project schedule and costs.

Q. What is the permitting status of the Staten Island Unbottling project?

A. The Staten Island Unbottling project will need permits and approvals from NY DEC, NJ DEP, NYC Buildings Department, and NYC Zoning Board approval. None of these permits have been obtained at this time. The projects also require resolution of interconnection issues with Cogen Technologies Linden Venture, L.P. ("Linden"), which are currently pending before FERC in Docket No. TX14-1-000.

Q. How do all of these conditions affect the costs of building the TOTS projects?

A. Any delays in construction as a result of the conditions imposed on the projects may result in increases in construction costs for the projects. Con Edison may also need to seek other regulatory approvals and conduct further studies due to the NYPSC's imposed conditions, which may affect the ability to complete the project in a timely fashion within budget. While these risks are currently being assumed by the incumbent transmission owners, the projects will be transferred to NY Transco, and may be completed by the NY Transco, depending on how soon they can be transferred. In any case, the risks to the NY Transco members are significant in terms of both commitments associated with formation, and the fact that it will inherit certain project development risks.

Q. Does NY Transco face any other unique challenges with the construction of these transmission projects?

A. Yes. Constructing these projects will be complicated because each involves a significant upgrade to the transmission network and are geographically dispersed. For example, the Fraser-to-Coopers Corners line is in Sullivan and Delaware counties, the second Ramapo-to-Rock Tavern line is in Orange and Rockland Counties between the service areas of Con Edison and Central Hudson, and the Staten Island Unbottling Project involves constructing substation upgrades in New York City that require coordination with PJM Interconnection, L.L.C. ("PJM") and Linden. The Staten Island Unbottling project is further complicated by interconnection and cost issues between Linden and Con Edison. Given that all three projects need to be placed into service in less than two years to meet the State's service reliability goals, the construction of these projects on this time schedule will present unique challenges with construction sequencing, and with coordination among electric utilities and two regional transmission organizations as well as State, Federal and in some cases local regulatory bodies. There are obvious challenges associated with permitting and constructing new transmission in this heavily populated region of the State.

Q. Does construction in these areas present any other unique risks or challenges?

A. The downstate region presents unique risks. Construction through congested areas introduces additional risks. For example, Staten Island Unbottling has two additional regulatory jurisdictions to seek approval in, New York City and New Jersey. And there could be local siting requirements for facilities in local communities. Additionally, one terminal of the Staten Island Unbottling project will be constructed on a third party owned site, Linden Substation, where the scope of work cannot be resolved until on-going interconnection issues are resolved, and the results could impact both the cost of the project as well as its timing. As such, delays in resolving these issues can lead to delays in commercial operation. Finally, the Staten Island Unbottling project interconnects two control areas, NYISO and PJM, which increases the challenges in addressing transmission and generation outage coordination during construction.

Q. Have any of the NYTOs begun construction on any of the TOTS projects?

A. No. Construction is expected to begin on the Second Ramapo-Rock Tavern 345 kV line first, commencing after all the remaining regulatory requirements that were specified in the NYPSC's order approving Con Edison's EM&CP are completed. This will occur prior to the transfer of the project to the NY Transco.

Q. Tell me about the AC Proceeding.

A. As Mr. Nachmias explains, the AC Proceeding was the proceeding initiated by the NYPSC to identify solutions to the public policy objectives to increase electricity flows between upstate and downstate regions of the state as outlined in the Governor's *Energy Highway Blueprint*. Specifically, the NYPSC identified the transmission corridors that "traverses the Mohawk Valley Region, the Capital Region, and the Lower Hudson Valley as a source of persistent congestion"[38] and noted that the upgrade of the transmission system in these corridors has the potential to bring significant benefits to New York's ratepayers. These are the Central East and UPNY/SENY transmission corridors. The NYPSC identified a need for an additional 1,000 MW of transmission capacity in this corridor. The

[38] NYPSC Case 12-T-0502 – Proceeding on Motion to Examine Alternative Current Transmission Upgrades, Order Instituting Proceeding (issued Nov. 30, 2012) at p. 1-2.

NYPSC solicited AC transmission solutions to meet the congestion relief objectives and provide additional public policy benefits such as improved system reliability, reduced emissions, and mitigation of reliability problems that may arise with generator retirements. In an Order dated April 22, 2013,[39] the NYPSC established the procedures for a comparative evaluation of proposed AC solutions. Four developers submitted projects in response to this solicitation.

Q. Did the NYTOs submit any transmission projects in the AC Proceeding?

A. Yes. The NYTOs submitted two of the TOTS projects—Ramapo-Rock Tavern and Fraser-Coopers Corners Reconductoring—and two additional transmission projects identified through the STARS study. Those two projects are the Oakdale-to-Fraser 345 kV transmission line and the 345 kV Edic-to-Pleasant Valley transmission line. The TOTS projects were recently withdrawn from the AC proceeding as they have been selected in the Reliability Contingency Plan Proceeding.

Q. Please describe the two AC projects in more detail.

A. More detailed descriptions of the projects are included in Exhibits Nos. NYT-16 (2nd Oakdale-to-Fraser 345 kV Line) and NYT-17 (Edic-to-Pleasant Valley 345 kV Line). Here is a brief summary of the projects:

- 2nd Oakdale-to-Fraser 345 kV Line. The project will establish a second 345 kV line from the Oakdale 345 kV Substation to the Fraser 345 kV Substation. The project will increase the import capability into southeastern New York during normal and emergency conditions. The project will be located in Broome,

[39] NYPSC Case 12-T-0502 – Order Establishing Procedures for Joint Review Under Article VII of the Public Service Law and Approving Rule Changes (issued April 22, 2013).

Chenango and Delaware Counties in New York. Approximately 57 miles will parallel NYSEG's existing 345 kV Line 32 along the existing right-of -way.

- Edic-to-Pleasant Valley 345 kV Line. This project as initially proposed is a new 345kV transmission line that will connect Niagara Mohawk's Edic Substation in Oneida County, New York to Con Edison's Pleasant Valley Substation in Dutchess County, New York, a total distance of approximately 153 miles. The project includes three new substations: (i) Princetown Substation in the Town of Princetown; (ii) Knickerbocker Substation in the Town of Schodack; and (iii) Churchtown Substation in the Town of Claverack. In addition, approximately seventy-five miles of two existing 80 mile 230 kV transmission lines, the #30 Porter-Rotterdam line and the #31 Porter-Rotterdam line, will be removed to allow for the construction of the new 345 kV line on existing rights-of-way. The remaining five miles of each of these transmission lines will be rebuilt to address age-related condition issues. This project will provide over 1,000 MW of additional transfer capability across UPNY/SENY and a significant increase to the Central East interface transfer capability.

The NYTOs expect to submit alternatives to these projects to address the NYPSC's new objective to stay within existing rights-of-way. Each of the alternatives will contribute to or meet the transfer capability objective, and it is expected that if successful, only one of these alternatives will be selected and it will be in lieu of the originally proposed Edic-New Scotland project.

Q. What are the benefits of the AC Projects?

A. The AC Projects will increase UPNY/SENY transmission capacity by more than 1,000 MW and will increase Central East capacity significantly. As such, they will also provide significant amount of congestion relief. As the NYPSC noted, congestion relief in this corridor has the potential to provide numerous benefits including "near-term benefits of enhanced system reliability, flexibility, and efficiency, reduced environmental and health impacts through reduced downstate emissions, and increased diversity in supply; as well as long-term benefits in terms of job growth, development of efficient new generating resources at lower cost in upstate areas, and mitigation of reliability problems that may arise with expected generator retirements."[40] The STARS analysis confirmed the broad range of benefits provided with the increased transmission capacity and corresponding reduction in congestion.

It is reasonable to believe that due to the greater scale of the AC projects, the benefits noted for the TOTS projects earlier would accrue to the AC Projects as well. These include:

- Increased transmission transfer capability into southeastern New York to provide greater flexibility in the event of downstate generator retirements;
- Increased transfer capability will allow for a reduction in capacity costs which recently increased by more than $200 million a year with the formation of a new capacity pricing zone in the lower Hudson Valley;
- Reduced transmission energy losses;
- Reduced congestion due to transmission outages;

[40] NYPSC Case 12-T-0502 – Order Establishing Procedures for Joint Review Under Article VII of the Public Service Law and Approving Rule Changes (issued April 22, 2013) at p. 1-2.

- Mitigation of extreme events and system contingencies;
- Reduced cost due to imperfect foresight of real-time system conditions;
- Reduced cost of cycling power plants;
- Reduced amounts and costs of operating reserves and other ancillary services;
- Mitigation of reliability-must-run (RMR) conditions;[41]
- Reduced emissions;
- Increased tax revenue;
- Increased employment; and
- Increased system resiliency and reliability.

Q. What are some of the risks and challenges of the AC projects?

A. The most immediate risk is whether the projects will be selected by the NYPSC and included in the NYISO transmission plan. The AC Proceeding has a couple of challenges that are unusual for transmission siting proceedings in New York. First, the AC Proceeding is a competitive proceeding. Four developers are currently competing to provide the transmission solution to the UPNY/SENY and Central East congestion problem. The NYPSC has not previously conducted such a proceeding, and the participants are following guidelines that are being implemented for the first time which creates uncertainty about the selection process.

Second, the AC Proceeding has resulted in community opposition. Residents in the vicinity of the southern forty mile length of the Edic-to-Pleasant

41 Reliability Contingency Plan Order at pp. 23-25.

Valley project oppose *any* new transmission project in their community. In 2014, the Governor proposed an expedited siting proceeding for projects that can stay within the existing "envelope" of the transmission corridor. The NYPSC responded by asking project developers to propose alternative projects in its AC proceeding that would stay within existing rights of way, which required projects to be redesigned to meet this requirement while still providing 1,000 MW of congestion relief to UPNY/SENY and Central East.

Third, the community opposition has initiated a campaign to discredit the need for these transmission projects citing other projects in the NYISO project interconnection queue, the recent NYISO withdrawal of project solicitation related to the 2014 RNA study, and changes in system load forecast and congestion forecasts.

Q. Are there any additional risks?

A. Yes. The AC Projects are major electric transmission infrastructure projects that will require many approvals and will face many development challenges. Among the obvious risks are:

- Some of the anticipated governmental and regulatory approvals are listed in Exhibit No. NYT-14. These all bring significant risk to the project schedule and the cost estimate. A number of these approvals may spawn additional analysis or approvals as was realized in the Ramapo-Rock Tavern project as noted earlier.
- Engineering challenges include developing a design to fit within the existing rights of way corridor, designing a project that can be safely

constructed adjacent to and interconnecting with existing electric facilities, and is cost effective.

- Project management risks include securing a large number of labor resources, coordinating project activities, managing the schedule and keeping the project within budget.
- Material procurement risks include: raw material and manufacturing availability, quality, and delivery logistics.

Q. Have any of the NYTOs begun construction on any of the AC projects?

A. No. Construction of the AC projects will not begin until all permits and approvals are received. As stated earlier, these projects are only in the early stages of siting review.

Q. Will the proposed projects make use of any new technological innovations?

A. Yes. The projects were assessed for the adoption of technologic innovations and innovative solutions to mitigate the need for additional rights of way. We assessed using the latest conductor technologies, structure designs, and system configurations, among other things. Some examples of the innovations adopted in some or all of the projects (including the AC projects discussed below) include:

- [redacted]
- Reconfiguration and more efficient use of existing assets to minimize real estate needs and mitigate environmental and visual impacts;

- Incorporating innovative compact structure designs to maximize use of existing rights of way corridors and mitigate visual impacts;

- Innovative construction techniques such as live-line construction and use of low impact vehicles will be assessed on some projects to minimize impacts to the environment and system reliability;

- Adoption of the latest microprocessor-based system protection technology to provide the best fault clearing capabilities and system monitoring data; and

- Adoption of the latest technology in digital fault recorders and sequence of event recorders which will provide the best capabilities to assess system disturbances.

Q. Does NY Transco and its affiliates have experience constructing large transmission projects?

A. Yes. Even though the NY Transco is a start-up transmission company, its owners are affiliates of the State's investor-owned electric utilities who are experienced operators of electric transmission. Accordingly, NY Transco will look to the NYTOs, consistent with federal and state affiliate rules to provide expertise for design, material procurement, project management and construction support. Nevertheless, it is important to recall that there have not been any major transmission projects constructed in the constrained corridors in decades, so coordinating the construction of large new transmission projects will be a challenge, particularly given the compressed construction schedule. NY Transco represents an historic effort by the investor owned utilities in New York to provide a coordinated solution to complex, geographically disperse but integrated construction projects. The complexity of this coordinated effort cannot be overstated.

Q. What are the estimated costs for the five NY Transco transmission projects?

A. In total, the five initial projects will result in an estimated total investment in the New York transmission system of approximately $1.7 billion in nominal dollars. The estimates for the TOTS projects are inclusive of financing costs whereas the AC projects do not include these costs.

<u>Five Initial Projects and Estimated Costs</u>

Project	In-Service Year	Estimated Cost (Nominal $ millions)
2nd Ramapo to Rock Tavern 345 kV Line	2016	$121
Staten Island Un-bottling	2016	$262
Fraser-to-Coopers Corners Reconductoring	2016	$66
Edic-to-Pleasant Valley 345 kV Line	2019	$1,022
Oakdale to Fraser 345 kV Line Upgrade	2019	$246
Total	---	$1,717

The cost estimates may change based on conditions or modifications required by government agencies.

Q. When will NY Transco present its final cost estimates for the five projects?

A. The NYTOs and NY Transco must complete the scope and engineering design for each project before a final estimate can be determined. Reaching that milestone for each project requires the issuance of major permits, such as issuance by the NYPSC of certificates of environmental compatibility and public need at the culmination of what is sometimes referred to as the “Article VII” process in reference to the public utility code sections that govern that review. Often it is also necessary to have Army Corp. of Engineers approvals, which can affect scope and cost as well. Once some of the major permits are issued, engineering design activities can commence, which will uncover any need to change project scope and thereby increase costs and incur delays. The engineering design activities will be performed concurrent with the procurement process whereby material costs will be firmed up and production slots will be secured. In addition, construction resources will be contracted which will identify if there is any labor resource deficiency which could impact project costs and schedule. As such, the estimates provided above are non-final and, given the need to obtain key governmental approvals, we cannot yet provide final budget estimates. It is also important to point out that these projects are currently being carried on the books of the various NYTOs where they are accruing expenditures in their Allowance for Funds Used During Construction accounts, also known as AFUDC accounts. The longer expenditures accrue on those accounts, the larger the balances will be when they are transferred to NY Transco. We anticipate that NY Transco will have final estimates for each project within four weeks after completion of the engineering and procurement activities.

Q. Will any of the NYTOs retain any part of the TOTS projects?

A. The TOTS projects include costs to upgrade or expand existing NYTO facilities. In most cases, those upgraded assets will be retained by the NYTO. These upgrades and expansions are often referred to as “System Upgrade Facilities” or “Connecting Transmission Owner Attachment Facilities.” It should also be noted that the NYTOs may have planned to complete upgrades on transmission facilities that will no longer be necessary with the construction of the AC Project or TOTS project. If that is the case, the NYTO planned capital investment cost will be avoided. Under the business arrangements, the affected NYTO will then make a contribution to NY Transco at a level commensurate with the avoided planned capital investment. The NYTOs refer to this as a "replacement-in-kind" contribution and such costs are not included in the project estimates.

Q. What steps will the NYTOs take to mitigate the costs and risks to completing these projects?

A. The NYTOs have experience developing electric transmission infrastructure projects. However, the scale of some of the TOTS and AC projects present unique challenges. Each of the projects will be led by a Project Manager with experience delivering transmission projects and identifying and mitigating risks. There are a number of steps that will be taken which may include the following. First, standard project management techniques will be utilized such as the development of a detailed schedule which identifies all project tasks, resources, and the sequences for such tasks. The schedule is a tool that provides the project team vision of what needs to be done, by when, and by whom. Second, standard procurement processes will be utilized to secure the materials and labor resources at competitive prices, which may include the use of a competitive bid process for needed materials. Third, best practices will be utilized to the maximum extent possible to help avoid repeating or encountering risks and incorporating lessons learned on previous projects. These processes have sometimes been vetted and approved by regulators. Thus using them will help to expedite the approval process. As an example, the Ramapo-Rock Tavern project has adopted the previously approved long term right of way management practices which was readily noted and accepted by NYPSC.[42] In this regard it is important to note that NY Transco is proposing to share the risks of cost over-runs with customers as explained by Mr. Nachmias. The risk sharing proposal gives NY Transco an added incentive to control costs and construct the projects consistent with its final estimates.

Q. Does this conclude your testimony?

A. Yes.

Q. Thank you.

[42] NYPSC Case 13-T-0586 – Petition of Consolidated Edison Company of New York, Inc. for Approval of Environmental Management and Construction Plan for Sugarloaf to Rock Tavern Segment of Second Ramapo to Rock Tavern 345 kV Transmission Line (Feeder 76), (issued Oct. 27, 2014) at p. 10.

STATE OF NEW YORK)
)
) ss
)
COUNTY OF DUTCHESS)

I, PAUL E. HAERING, being first duly sworn on oath depose and say as follows:

The foregoing "Prepared Direct Testimony of Paul E. Haering and Richard W. Allen on Behalf of New York Transco, LLC" was prepared by me and the other witnesses listed therein, or under the supervision of one or more of such witnesses, and the factual statements contained in such testimony are true and correct to the best of my knowledge, information and belief.

Further affiant saith not.

Paul E. Haering
Paul E. Haering

On this 2nd day of December, 2014, before me, the undersigned notary public, personally appeared Paul E. Haering and acknowledged to me that he signed the forgoing document voluntarily for its stated purposes. I identified Paul E. Haering to be the person whose name is signed on the forgoing document by means of the following satisfactory evidence of identity (check one):

✓ Identification based on my personal knowledge of his/~~her~~ identity, or

___ Current government-issued identification bearing his/her photographic image and signature.

Donna M. Giametta

Notary Public

My commission expires:

(SEAL)

DONNA M. GIAMETTA
Notary Public, State of New York
No. 01GI5067398
Qualified in Ulster County
Commission Expires Oct. 15, 2018

STATE OF NEW YORK)
)
) ss
)
COUNTY OF ALBANY)

I, RICHARD W. ALLEN, being first duly sworn on oath depose and say as follows:

The foregoing "Prepared Direct Testimony of Paul E. Haering and Richard W. Allen on Behalf of New York Transco, LLC" was prepared by me and the other witnesses listed therein, or under the supervision of one or more of such witnesses, and the factual statements contained in such testimony are true and correct to the best of my knowledge, information and belief.

Further affiant saith not.

Richard W. Allen

Richard W. Allen

On this 18 day of December, 2014, before me, the undersigned notary public, personally appeared Richard W. Allen and acknowledged to me that he/she signed the forgoing document voluntarily for its stated purposes. I identified Richard W. Allen to be the person whose name is signed on the forgoing document by means of the following satisfactory evidence of identity (check one):

✓ Identification based on my personal knowledge of his/her identity, or

___ Current government-issued identification bearing his/her photographic image and signature.

Jane D. Catalano

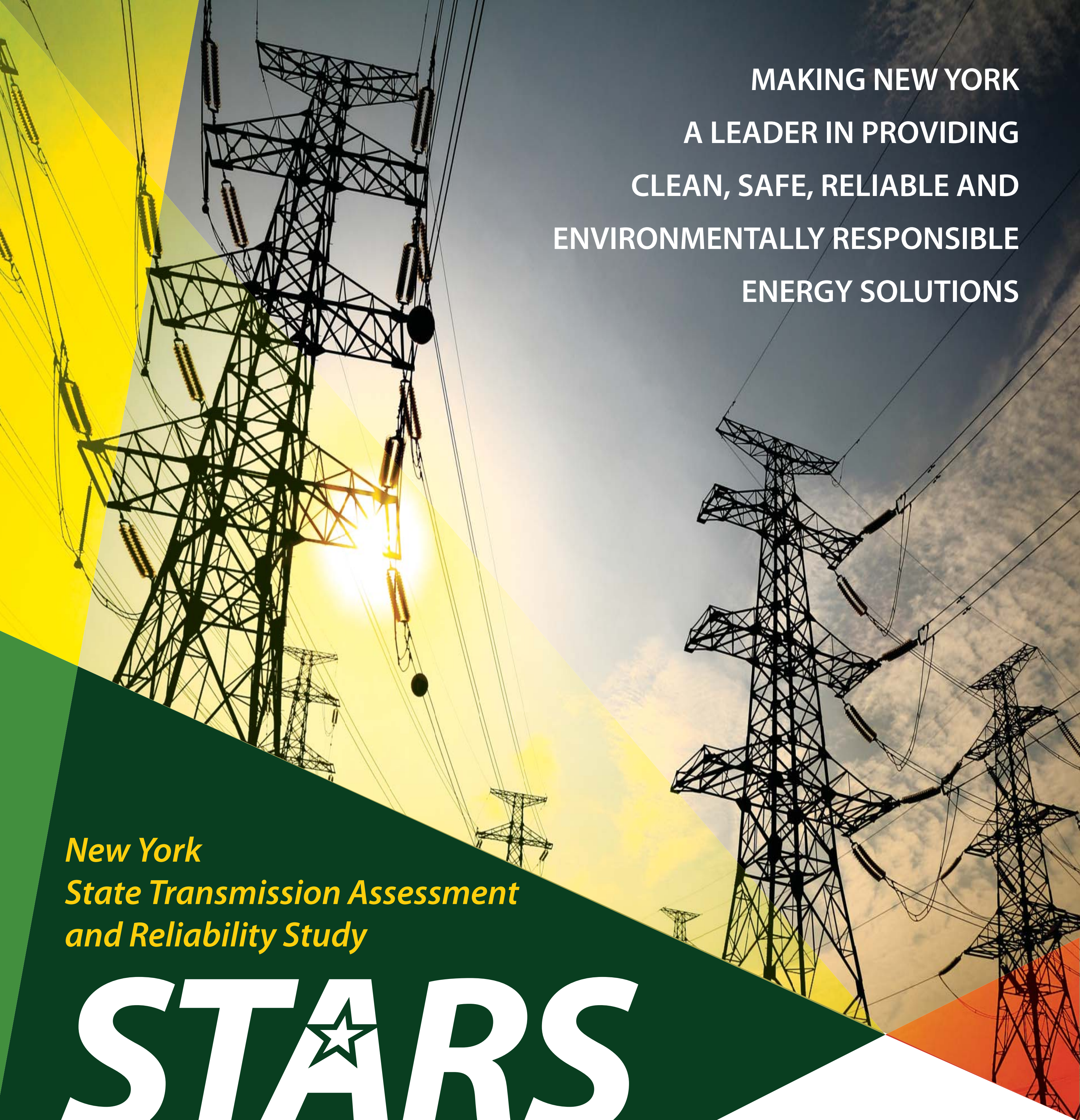
Notary Public

My commission expires: 11/6/2018

(SEAL)

JANE D. CATALANO
Notary Public, State of New York
Qualified in Albany Co. No. 4777517
Commission Expires 11/6/2018

Exhibit No. NYT-5



MAKING NEW YORK
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ENERGY SOLUTIONS

New York
State Transmission Assessment and Reliability Study

STARS

Phase II Study Report

Prepared by the STARS Technical Working Group
April 30, 2012

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1

Executive Summary

1.1 Executive Summary

Overview

Electric transmission plays a significant role in New York's "energy highway." However, the aging transmission system is making for a bumpy ride.

The last major cross-state transmission project was built in the 1980s; 85 percent of the state's transmission lines were built before 1980. And age is not the only challenge on the horizon:

CONGESTION

There is congestion along the 11,600 miles of high-voltage transmission lines in New York, with one-third of the state's electric load located in the proximity of New York City. The transmission pathways from upstate to downstate do not have enough capacity to carry all the electricity that could flow efficiently. The measured impact of this congestion for New Yorkers in 2010 was $1.1 billion.[1]

LINES NEED TO BE REPLACED

Based on a high level age based condition assessment nearly 4,700 miles of lines will approach end of life and may require replacement within the next 30 years.

COAL PLANTS MAY NEED TO CLOSE

Some coal and oil plants may no longer be viable due to a combination of factors which include low gas prices and a potential increase in the cost of environmental compliance.

GENERATION FLEET AGING

The state's electricity generation fleet is aging, with 42 percent of generation plants more than 40 years old.

In an effort to proactively address these looming issues, a new transmission planning study in New York was initiated — the New York State Transmission Assessment and Reliability Study, or STARS for short. The study, which began in 2008, is being conducted and funded by the state's transmission owners, with support from the New York Independent System Operator (NYISO)[2] and consultant ABB.

[1] NYISO 2011 CARIS Report

[2] The NYISO is a private, not-for-profit body that was formed pursuant to New York's deregulation of its energy system more than a decade ago. NYISO operates the transmission grid in New York and sets the price paid for wholesale energy through a complex set of rules and programs.

A team of engineers and experts — known as the STARS Technical Working Group — is thoroughly examining New York's electric transmission system, with a focus on identifying the system's infrastructure needs for the future. The study's long-term planning approach will help transmission owners develop an updated, more reliable system that meets New York Control Area requirements for the next 20 years and beyond.

Preliminary findings of the STARS effort indicate that $25 billion may be spent over the next 30 years if all of the transmission lines identified through the age-based condition assessment were to be replaced. Additionally, $2.5 billion worth of potential projects (including upgrades to existing lines as well as constructing several new lines) have been identified.

Who are the transmission owners in New York?

It's a public/private partnership that includes:

- » **Central Hudson** (Central Hudson Gas & Electric Corp.)
- » **Con Edison** (Consolidated Edison Company of New York, Inc.)
- » **LIPA** (Long Island Power Authority)
- » **National Grid**
- » **NYPA** (New York Power Authority)
- » **NYSEG** (New York State Electric and Gas Corp.)
- » **O&R** (Orange & Rockland Utilities, Inc.)
- » **RGE** (Rochester Gas & Electric Corp.)

The benefits: Issues lead to opportunities

With careful planning and a long-term approach to developing solutions to future energy needs, the energy issues that New Yorkers face can be turned into opportunities. Consider the good news:

EASE CONGESTION

Congestion in the transmission system can be reduced through expansion of the system, turning current energy "roadways" into "highways." This larger capacity can provide statewide economic benefits by increasing the transmission capability from upstate to downstate.

USE EXISTING RIGHTS-OF-WAY

Existing transmission lines' rights-of-way can be used; it offers the least cost and quickest solution, requires no new corridors, minimizes environmental impact associated with siting and construction, and offers an opportunity to upgrade rather than just replace in-kind key portions of the system.

IMPROVE RELIABILITY

Improving the robustness of the electric transmission system through upgraded and new lines improves the reliability of the system. This enhanced reliability has the potential to reduce the amount of generation necessary for the system to operate reliably.

CREATE JOBS & ECONOMIC GROWTH

Developing an improved energy highway will create jobs and economic growth. In addition to creating thousands of construction jobs, it will generate millions of dollars in additional property taxes and add to the regional gross domestic product (GDP). Every $100 million spent will generate $3 million annually in property tax revenue.

IMPROVE THE ENVIRONMENT

A more efficient energy system means a better environment. A more robust system can accommodate more upstate wind generation and displace less environmentally friendly energy generation such as coal and oil.

MEET CLEAN AIR AND PUBLIC POLICY GOALS

New York will be at the forefront in being prepared to address the impacts of upcoming federal clean air regulations.

Key public policy objectives (such as goals for renewable energy and energy efficiency), as well as the need for a contingency plan for the potential retirement of Indian Point Energy Center, will be advanced.

Overall, a more efficient system will reduce customers' electricity costs; and make New York a leader in providing clean, safe, reliable and environmentally responsible energy solutions.

Scope of the current NYISO system planning process

Compared to STARS' long-range planning horizon, the NYISO's system planning process utilizes a 10-year study horizon that may not identify potential longer-range transmission needs. The NYISO study — the Comprehensive System Planning Process, or CSPP — has two components:

1. **Comprehensive Reliability Planning Process (CRPP);**
2. **Congestion Assessment and Resource Integration Study (CARIS).**

The first component — the Comprehensive Reliability Planning Process (CRPP) — features a reliability needs assessment and a comprehensive reliability plan, which identifies the resources needed on the bulk power system[3] to fulfill federal, regional and state reliability rules, including sufficient capacity to meet New York State Reliability Council's Loss-of-Load Expectation (LOLE) criterion.[4]

One assumption in this planning process is that aging assets continue to operate reliably without consideration of the need for replacement.

The second component of NYISO's planning process — the Congestion Assessment and Resource Integration Study (CARIS) — uses analysis of past and projected congestion statistics to identify the power elements with the most congestion. A benefit/cost analysis of generic generation, transmission and demand-side solutions is performed; then, developers may submit specific transmission solutions for analysis, and beneficiary vote, to determine the project's eligibility for cost recovery under the NYISO Tariff.

When the NYISO's tariff-mandated planning process is augmented by a longer time horizon study such as STARS, additional effective and economical solutions for the state's mature power system (characterized by slower load growth and aging facilities) can be identified. The longer time horizon for planning is necessary to:

6 REASONS FOR A STUDY WITH A LONGER TIME HORIZON

1. **Evaluate whether higher transmission voltage or new technology is necessary and economical.**
2. **Incorporate the need to replace aging infrastructure (transmission lines and substations).**
3. **Address existing limited rights-of-way and siting issues.**
4. **Consider effective integration of renewable resources.**
5. **Meet reliability needs across the New York Control Area system for various resource expansion scenarios.**
6. **Consider emerging technological and regulatory issues with longer-term implications, such as plug-in electric vehicles.**

The above factors are overlapping in nature. Considering all of these factors at the same time will offer a significant number of alternatives and options. As the number of alternatives increase, the effort required for analyses increases substantially.

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[3] Bulk power system means high-voltage transmission (typically 115 kV and greater). It is the "backbone" that transfers electricity around the state to the various load centers. kV is the abbreviation for kilovolts.

[4] LOLE criterion is one day in 10 years, or an annual statewide Loss-of-Load Expectation of no greater than 0.1 days per year.

Long-range planning challenges

The longer planning horizon introduces significant challenges. One of the most challenging issues for long-range transmission planning under open market conditions is the uncertainty associated with new generating plants, including location, size, type, etc. as well as future generator retirements. If a new transmission project is built (including uprating, upgrading) and the new generation does not materialize at the location or in its anticipated size (or capacity), then the new transmission becomes an underutilized asset. Or, in a reverse situation, the transmission becomes limiting, potentially affecting the reliability and congestion of the power system.

Similar issues with respect to the degree of penetration and the location of demand-side resources also exist.

The STARS approach

In light of the uncertainties, the most practical approach is to advance various scenarios of future resource development, and to determine a range of transmission solutions and projects for the defined scenarios. The consideration of various future resource development scenarios significantly increases the amount of effort needed for analyses. However, using carefully considered scenarios, combined with appropriate sensitivity evaluations, assists in defining the transmission capacity requirements to meet reliability criteria and/or provide economic benefits.

Inclusion of aged facilities and renewable resource development to identify a robust mix of transmission alternatives further complicates the analyses. Therefore, the STARS Technical Working Group divided this study into two phases:

1. **PHASE I:** Identify the need for additional transfer capability to meet statewide LOLE with the existing transmission system.
2. **PHASE II:** Identify the most suitable, cost effective transmission alternatives to meet additional transfer capability while considering aged infrastructure and integration of renewable resources.

STARS findings: The details

Several key findings provide guidance for strategic long-range investment needs for the state's transmission system. These investments will ensure that aging infrastructure is replaced, and in some cases upgraded, in a prudent and coordinated manner to maintain and enhance system reliability. These findings take into account the value of utilizing existing transmission lines' rights-of-way, as well as projects that can assist in achieving New York State's Public Policy goals.

1. **40% of the existing transmission system will likely need to be replaced over the next 30 years:** The state's transmission infrastructure is well maintained, but aging. A high-level aged based condition assessment by the STARS TWG of this infrastructure has identified the potential need to replace, over the next 30 years, nearly 4,700 miles of transmission lines at operating voltages of 115 kV and greater. The estimated cost of this replacement is more than $25 billion.
2. **Study assumptions including generation location, type and fuel price forecasts significantly impact findings:** The longer time horizon of the study introduces uncertainty related to key assumptions including forecasted load levels, new generation resources including locations, size and type, as well as similar issues regarding the degree of penetration of and locations of demand side resources. The actual future mix of generation types, fuel costs, emission regulation and allowance prices, as well as the location of new generation additions can have a significant impact on the results of the study.
3. **Reliability needs are met under the statewide generation expansion scenario:** Based on the selected statewide generation expansion scenario, which assumed that

generation was added proportional to load growth, the system meets existing reliability criteria. This scenario did not include significant expansion of the capability of imports from external control areas, such as Hydro-Quebec. This statewide generation expansion scenario represents a conservative view of potential transmission needs. Analysis of other generation expansion scenarios where more generation is sited upstate or where imports are relied on more heavily, show that the system does not meet established reliability criteria, increasing the need for more transmission.

4. **New transmission will unbottle wind resources:** The NYISO has identified as part of their 2010 Wind Generation Study that as part of the integration of 6,000 MW of wind resources nearly 9% of the wind energy production in three upstate areas would be "bottled" or be undeliverable to the transmission system. The study identifies and models the impacts of the underlying local transmission system upgrades that will allow for the nearly full unbottling of these resources. These upgrades allow for the full utilization of these resources which have been constructed under the State's Renewables Portfolio Standard. The STARS study assumed that these upgrades were in place. The approximate cost of these upgrades ranges from $75 million to $325 million, depending upon the scope of the upgrades constructed. No assumptions in the STARS study were made on how these projects would be developed, but they represent additional transmission investment opportunities.
5. **New transmission projects with economic benefits:** The study has identified several projects that provide economic benefits by increasing transfer limits on existing constraints within the state's grid. Projects such as the 3rd Leeds to Pleasant Valley line, a 3rd New Scotland to Leeds line and 2nd Rock Tavern to Ramapo line show promise. These lines would be located within or with minor expansion of existing rights of way. The estimated costs of these projects are slightly over $400M. These projects show annual net benefits based on production cost savings of $18M per year.
6. **Cost effective incremental transmission upgrades:** Based on the overlay of the condition assessment work and the STARS trials there are upgrade projects that provide increased transmission capability at a relatively modest cost. Projects such as the upgrade from 230 kV to 345 kV of the Moses to Marcy lines, Marcy to Rotterdam section of the Marcy to New Scotland line and the Oakdale to Fraser line are good examples. Again these lines would be located within or along existing transmission corridors. The replacement costs of these lines is approximately $1.0B, with the estimated additional upgrade costs of these projects slightly over $600M.
7. **Ancillary benefits of a more robust system:** The system transmission upgrades studied in STARS improve the robustness of the transmission system, which in turn have the potential to reduce the levels of generation reserves required to maintain system reliability.
8. **Upgrades to Moses South are further justified with increased Hydro Quebec imports:** The NYCA import limit from the Quebec Chateauguay-Massena single 765 kV interconnection was modeled at 1,380 MW per current NYISO operating criteria, which prevents a single external NYCA source from exceeding the largest internal contingency, in this case Nine Mile Point Station #2 at a projected capacity of 1380 MW. The thermal capability of the Chateauguay substation, with four 765/120 kV transformers placed in service, is approximately 2370 MW. The operating limitation on the Chateauguay-Massena 765 kV line as a single source limited the benefit that can be realized by the Moses South 230 kV to 345 kV upgrades in the STARS Base Transmission Plan.
9. **HVDC lines may help meet public policy objectives:** The HVDC lines from Pleasant Valley to NYC and Long Island that were analyzed as part of the study do not

appear to be justified based on either reliability or economic benefits, but may be justified based on Public Policy goals.

Recommendations

The following recommendations are supported by the analysis performed as part of the STARS effort.

1. Each Transmission Owner should continue to assess the condition of their assets to provide for the long-term reliability of the state's transmission infrastructure as part of their normal capital planning process.
2. Coordinated transmission studies (such as STARS) should be performed and updated on a periodic basis as they provide a mechanism to develop optimized, long-term investment strategies for the state's transmission infrastructure.
3. There are several projects that reduce congestion and provide economic benefits through lower production costs; these projects should be pursued. These 345 kV projects include the 3rd Leeds-Pleasant Valley line, 3rd New Scotland-Leeds line and 2nd Rock Tavern-Ramapo line. Construction of these lines leverages, to the extent possible, the use of existing rights-of-way.
4. To meet state public policy objectives of increased renewable resources, the underlying local upgrades identified in the NYISO 2010 Wind Generation Study should be constructed based on a review of the status of the development of the wind projects in the three upstate areas identified in that study. This would lead to greatly improved deliverability of wind resources and reduced emissions.
5. The export limit from Hydro-Quebec's Chateauguay station to New York is approved at 2,370 MW with all equipment in service, which includes four 765/120 kV transformers. The NYCA import limit from the Quebec Chateauguay-Massena single 765 kV interconnection is, however, limited to 1,380 MW per current NYISO operating criteria, which prevents a single external NYCA source from exceeding the largest internal contingency, in this case Nine Mile Point Station #2 at a projected capacity of 1,380 MW. If there is a desire, from a public policy perspective, to increase the import capability of hydro generation from Quebec, additional analysis would be needed to determine how to best address the loss of single source contingency.
6. Specific projects were identified (3rd Leeds to Pleasant Valley line and 2nd Rock Tavern to Ramapo line) that can be a significant part of solving the reliability needs that would be created with the potential retirement of the Indian Point Energy Center. Several other projects such as the Marcy South Series Compensation and Staten Island Generation Unbottling projects were not evaluated as part of the study, but should be further considered since they appear to provide additional value in addressing this contingency.
7. Several transmission lines that are approaching the end of their useful life should be considered for upgrading to improve the strength of the transmission system backbone. These projects include the upgrade to 345 kV of the Moses to Marcy, Marcy to Rotterdam section of Marcy to New Scotland line and the Oakdale to Fraser line. Upgrades of these lines leverages the use of existing rights-of-ways.

The STARS Study has been conducted in accordance with FERC Order 890 requirements. Periodic updates have been made and stakeholder input sought through the NYISO's Transmission Planning Advisory Subcommittee (TPAS). This report and its attachments are available at the following links:

http://www.nyiso.com/public/webdocs/services/planning/stars/Phase_2_Final_Report_4_30_2012.pdf
http://www.nyiso.com/public/webdocs/services/planning/stars/Phase_2_Final_Report_Attachments 4_30_2012.pdf

Through implementation of the above STARS recommendations, New York will reap the benefits of a more robust transmission system including reduced congestion, improved reliability, enhanced environmental benefits and support for other State Public Policy goals. This will make New York a leader in implementing a clean, safe, reliable and environmentally responsible energy future.

1.2 Abbreviations/Definitions

Base Transmission Plan (BTP): The Initial set of transmission system upgrade projects proposed by the TWG, sometimes referred to as Trial 0, or Initial.

BTP Trials: Subsequent sets of transmission system upgrade projects that are a subset of the BTP. Individual BTP Trials are identified by their trial number, i.e. Trial 1.

Technical Working Group (TWG): The group that performed the technical analysis associated with the STARS Study. Members included representatives from Central Hudson Gas & Electric Corporation ("Central Hudson"), Consolidated Edison Company Of New York, Inc. ("Con Edison"), Long Island Power Authority ("LIPA"), National Grid ("National Grid"), New York Power Authority ("NYPA"), New York State Electric And Gas Corporation ("NYSEG"), Orange & Rockland Utilities, Inc. ("O&R") and Rochester Gas & Electric Corporation ("RGE"), and the New York Independent System Operator ("NYISO"). The STARS TWG contracted with ABB to perform parts of the Study.

Reference Case: Used in the sensitivity analysis – base set of assumptions

Sensitivity Case: Adjustment to the base set of assumptions

Replacement Plan: Pre project case that includes underlying upgrades and wind projects

Production Cost: Total cost of the Generators required to meet Load and reliability Constraints based upon the usual measures of Generator production cost (e.g., running cost, Minimum Generation Bid, and Start Up Bid).

Location Based Marginal Price (LBMP): A Locational Based Marginal Price (LBMP) consists of an energy, congestion, and loss component relative to a reference bus. LBMPs represent the incremental value of an additional MW of energy injected at a particular location.

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.

Loss of Load Expectation (LOLE): LOLE establishes the amount of generation and demand-side resources needed - subject to the level of the availability of those resources, load uncertainty, available transmission system transfer capability and emergency operating procedures – to minimize the probability of an involuntary loss of firm electric load on the bulk electricity grid. The state's bulk electricity grid is designed to meet an LOLE that is not greater than one occurrence of an involuntary load disconnection in 10 years, expressed mathematically as 0.1 days per year.

Horizon Year: Planning Horizon for STARS Study. This corresponds to a 20+ year timeframe from now to the year 2030 or later. The NYCA peak load level in the Horizon Year is assumed to be 40,816 MW. See Section 5.1.

Intermediate Year: Halfway period between now and the Horizon Year. The NYCA peak load level in the Intermediate Year is assumed to be 37,130 MW. See Section 5.1.

New York Independent System Operator (NYISO)

New York Control Area (NYCA)

Hydro-Quebec (HQ)

Congestion Assessment and Resource Integration Study (CARIS)

Hudson Transmission Project (HTP)

2

Phase I Summary

Phase I Summary

The STARS Phase I portion of the study focused on defining the long term, approximate 20-year horizon, electric transmission system needs within New York State.

Identifying the most economical and effective solutions for a mature power system, characterized by slower load growth and aging facilities such as exists in the State of New York power system, requires a longer time horizon than the 10 year period of CSPP. More specifically, the longer time horizon is necessary to:

1. evaluate whether a new transmission voltage or technology is necessary and economical
2. incorporate the need to replace aging infrastructure (transmission lines and substations)
3. address various existing limited rights-of-way and siting issues
4. consider effective integration of renewable resources (wind, solar)
5. meet varying reliability needs across the NYCA system in a coordinated manner
6. consider emerging technological and regulatory issues, such as smart grid and plug in electric vehicles, under a reasonable number of potential future scenarios

The above six factors are overlapping in nature. Considering all of these factors at the same time will expand the possibilities to a large number of alternatives and options. As the number of alternatives increase, the amount of effort required for analyses increases substantially.

Generation and transmission are intrinsically connected. One of the most difficult issues for long-range transmission planning under competitive market conditions, is the great uncertainty associated with future additions of new generation plants/units, including location, size, type etc. In theory, generation should be sited close to load centers. However, siting constraints and open market dynamics do not always bear that result. Therefore, transmission must often be built to access the electricity from the generation plant, but is not without risks. If a new transmission project is built and the new generation does not materialize at the location or in its anticipated size (or capacity); then the new transmission becomes an under utilized asset. In the case of reverse situation, the transmission becomes limiting, thereby potentially affecting the reliability and economics (congestion) of the power system. Similar issues with respect to the degree of penetration and the location of demand side resources also exist. In light of these uncertainties, the most practical approach is to postulate various scenarios of future resource development and to determine a range of transmission solutions or projects for the pre-defined scenarios. Even though the scenario approach considerably increases the amount of effort required for the analyses, using carefully considered scenarios combined with appropriate sensitivity evaluations will assist in defining the transmission capacity requirements for meeting the reliability criterion.

2.1 Load levels

In any planning study the starting point is to define a base forecasted load level. The load growth in New York for the past 30 years has been uneven and in recent years has declined; accordingly there is a high degree of uncertainty regarding future electric load within the state. When Phase I of the STARS study began, the most recent load forecast was in the 2008 NYISO Gold Book. Using the published 2018 50/50 non-coincident peak summer load forecast of 37,130 MW, and the corresponding annual growth percentages, in the STARS Study horizon year of 2030, the NYCA load level is projected to be 40,816 MW. This represents the base forecasted load level in the

STARS study. This level of load may happen earlier or later, depending upon the load growth that actually occurs. An example of a higher load growth scenario is a high penetration of plug-in electric vehicles. Conversely, slower load growth could occur due to aggressive energy conservation and efficiency programs, distributed generation etc. A load level of 37,130MW for the Intermediate Year (about half-way of the planning horizon) was assumed. As a reference, the summer peak load for the year 2009 was 30,844 MW; whereas the record peak load of 33,939MW occurred during the summer of 2006.

2.2 Capacity expansion scenarios

The STARS-TWG formulated four scenarios, as a "mix and match" of regional and statewide generation coupled with low and high import possibilities (Figure 2-1). Thus, the four scenarios (#1 through #4) span a wide range of future generation development possibilities and thus define boundaries or "book-end" possibilities. Further, with the Renewable Portfolio Standards (RPS) goals of the state in mind, two additional Scenarios (#5 and #6) explicitly including higher levels of wind generation have also been included. The total new generation capacity added by the Horizon Year for each scenario is based on the installed capacity reserve margin (IRM) of 16.5% that was in effect when the Study started, translating to 5,015MW for Scenarios #1 through #4. Due to lower and differing capacity factors associated with on-land and off-shore wind farms as well as non-coincidence of the maximum wind generation with the system peak load, the total new generation installed capacity requirement (to equal the effective or UCAP requirement of scenario's #1 thru' #4) is 6,834MW for Scenario #5 and 7,740MW for Scenario #6. Therefore, higher wind generation scenarios will likely require an increased IRM.

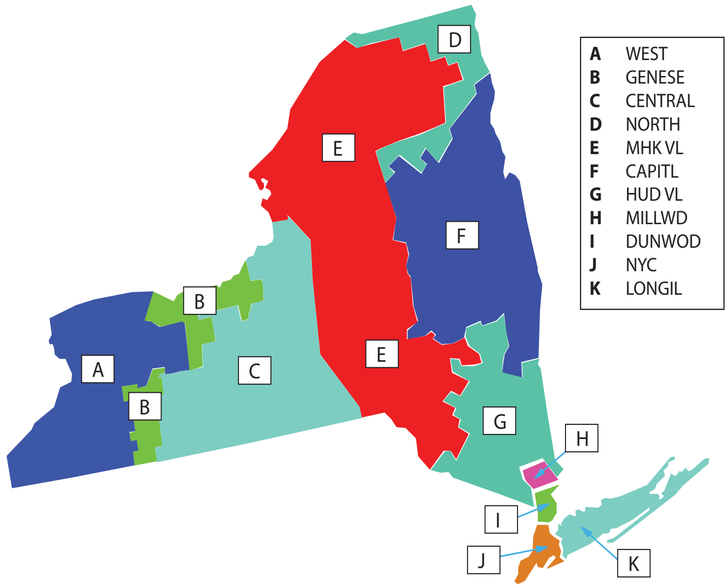
Figure 2-1 Generation expansion scenarios

Scenario	Future capacity scenario	Internally located capacity (as percentage of incremental capacity requirement)	Externally located capacity imports (as percentage of incremental capacity requirement)	Location of externally located capacity imports (as percentage of incremental capacity requirement)
1	Downstate capacity increased	85%	15%	10% ISONE (Zone K)
		Zones H-K		5% PJM (Zone J)
2	Upstate capacity increased	50%	50%	25% PJM (Zones A/C)
		Zones A-F		25% HQ (Zone D)
3	Statewide capacity — low imports	90%	10%	3.3% ISONE (Zone F/G)
		Zones A-K		3.3% PJM (Zone J)
				3.3% HQ (Zone D)
4	Statewide capacity — high imports	25%	75%	25% PJM (Zones I/J/K)
		Zones A-K		50% HQ (Zones D)
Scenarios with wind resources for 25% energy				
5	Downstate capacity	85%	15%	10% ISONE (Zone K)
	Renewables located downstate	Zones A-K		5% PJM (Zone J)
6	Upstate capacity	50%	50%	25% PJM
	50% of renewable capacity located upstate; 50% external	Zones A-F		25% HQ

2.3 Reliability criterion

The resource adequacy reliability criterion for the New York State bulk electricity system is a Loss of Load Expectation (LOLE) of one day in 10 years or 0.1 days per year. Emergency assistance available from external areas (PJM, ISO-NE, Ontario and Hydro-Quebec) is included for the calculation of LOLE. These external areas are also assumed, consistent with the NYISO Reliability Needs Assessment (RNA) assumptions, to achieve the target resource reliability criterion (LOLE of 1 day in ten years) on a multi-area or interconnected operation basis.

Figure 2-2 New York control area load zones



2.4 Methodology

The main methodology for this Phase-I Study is to determine the transmission capacity requirements for various scenarios to meet the above-mentioned LOLE. The primary tool used for LOLE calculation in this study is GridView[5]. In this model a full representation of the transmission network is used. In addition to the detailed transmission network representation, the GridView model contains various constraints for transmission lines, interfaces, contingency constraints, monitored lines, nomograms and emergency operating procedures (EOP).

Figure 2-3 Emergency transfer limits for LOLE calculations for the existing transmission system (intermediate year)

Interface	Limit MW
Dysinger East	2,504 (V)
West Central	1,134 (V)
Moses South	1,971 (V)
Volney East	3,952 (V)
Total East (Closed)	6,270 (V)
Central East	2,604 (V)
Central East + Fraser-Gilboa	2,916 (V)
CE Group	4,587 (V)
F to G	3,485 (T)
UPNY-SENY Open	5,124 (T)

(T) = Thermally constrained
(V) = Voltage constrained

Interface	Limit MW
UPNY-ConEd Open	5,392 (V)
Millwood South Closed	8,161 (V)
Dunwoodie South Plan	5,780 (T)
I to J	4,460 (T)
I to K (Y49/Y50) with Y49 flow set to 637	1,238 (T)
I to K (Y49/Y50) with Y49 flow set to 637 and Y50 RateA=653 MVA	1,293 (T)
I to J+K	5,413 (V)
LI import (with LIPA imports maximized)	2,851 (T)
LI import (with LIPA imports maximized and Y50 RateA=653 MVA)	2,905 (T)
Marcy South	1,686 (V)

[5] GridView is ABB's reliability analysis and market simulation software using Monte Carlo simulations. Gridview results benchmarked are very close to the values from GE Multi-Area-Reliability Simulation Program used by NYSRC and NYISO for LOLE studies

2.5 Transfer limits

The Interface Transfer Limits, which are defined as the amount of electricity that can flow on a transmission line at any given instant, respecting facility rating and reliability rules, for both Cross-State and External areas (Figure 2-3) were computed for the existing transmission topology and the intermediate year conditions and are close to the NYISO 2009 RNA assumptions and findings. These limits are used in the Gridview model for the LOLE calculations.

2.6 Calculated LOLE for the six scenarios

The LOLE index was calculated for each of the six scenarios (Figure 2-4. For Scenarios #1 and #5, the calculated LOLE values show that the postulated generation expansion plans combined with the existing transmission capability can meet the target reliability index of 0.1 days/year. This can be attributed to most of the new generation capacity (85%) being added in the downstate load zones for these two scenarios. In Scenario #3, the new generation (90%) was distributed proportionally to each zone across the state and resulted in an LOLE that did not meet the targeted reliability level. Scenario #4, with a heavy emphasis on out of state imports (75% of new capacity) shows that LOLE criterion cannot be met with the existing transmission system. The Scenarios #2 and #6 (with 50% of generation in the upstate zones and the other 50% from external imports) have the highest LOLE of the generation expansion scenarios studied and hence reliability criterion cannot be met with the existing transmission system. The LOLE value for Scenario #6 (similar to Scenario#2, but with more wind) is a bit higher, because the installed generation capacity considered for Wind Scenarios is in the up-state zones. Similar comparison can be made between LOLEs for Scenarios #1 and #5.

***Figure 2-4** Calculated LOLE values for six generation expansion scenarios (horizon year) with existing transmission*

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
NYCA LOLE days/year	**0.06**	**1.68**	**0.20**	**0.44**	**0.07**	**1.82**
Reliability criteria met?	YES	NO	NO	NO	YES	NO

2.7 Additional transmission capacity for scenarios 2, 3, 4 & 6

The study results have shown that the reliability criterion is only met for Scenarios #1 & #5 which assumes significant new generation being added downstate. However, the LOLEs for Scenario #s 2, 3, 4 and 6 (new upstate generation, low/high imports, more wind) are above the desired value. In order to estimate the additional transmission capacity needed to reduce the LOLE values to 0.1 days/year the GridView simulations were repeated for these four Scenarios to determine the additional transmission MW needed for each of the Interfaces (Figure 2-5) to achieve the reliability criterion. Because Scenarios #5&#6 are similar to Scenarios #1&#2, results for only the four primary scenarios are shown in Figure 2-5. The values in green color show the lowest amount of needed MW, the red color the highest amounts and the black color for in-between amounts. The MW need for each scenario (shown in each column) should be interpreted to be simultaneous, i.e. all the interface transfer limits need to be increased to the levels shown. In other words, increasing only one or a few of the interfaces to the shown MW levels is not sufficient to achieve the LOLE criterion. The actual upgrade to all the Interfaces will likely be somewhere between the boundaries of the low and high values in red, as they define the book end limits.

Figure 2-5 Additional transmission capacity need for the four scenarios (horizon year)

Additional transfer capability (MW) need

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CE Group	0	1,460	150	1,185
UPNY-SENY	0	1,735	249	702
Volney East	0	1,314	492	648
Central East	0	1,047	279	1,106
I to J	0	1,135	386	424
Y49Y50	0	752	159	972
F to G	0	1,171	187	399
Total East	0	1,274	0	456
West Central	0	265	316	192
Marcy South	0	435	15	257
Moses South	0	0	0	228
HQ-D	0	0	0	550

The values in Figure 2-4 are shown to a precision of one MW. For practical purposes, the values will be rounded when considering the MW need in Phase II when transmission alternatives are being analyzed for those scenarios which require transmission reinforcements.

The values in Figure 2-5 are shown to a precision of one MW. For practical purposes, the values will be rounded to the nearest 25 MW when considering the MW need in Phase II when transmission alternatives are being analyzed for those scenarios which require transmission reinforcements.

2.8 Transition from Phase I to Phase II

The actual expansion of the NYCA transmission grid should be adapted to account for the constantly evolving load growth, location and magnitude of future resource capacity additions, and assumed emergency assistance from neighboring control areas. For example, additional resource capacity assumed Downstate (Scenario 1) was shown to mitigate or eliminate the need for transmission expansion for the study horizon, without consideration of aged infrastructure. Conversely, resource capacity assumed for Upstate (Scenario 2) showed a need to expand the transmission system to satisfy system reliability requirements. The reliability needs along with the aging infrastructure needs and the delivery of renewable resources are all considerations within Phase II of the study. In addition to the study objectives of satisfying system reliability needs, as well as establishing coordinated efforts to address aging infrastructure needs and identifying projects that achieve public policy objectives such as the deliverability of renewable resources, Phase II of the study also evaluated projects that provide economic benefits to the state by relieving known constraints that exist within the system. By considering all of these important objectives the study provides a holistic evaluation of the potential transmission projects best suited to achieve them. As with any study of this type, time will tell which scenario reflects more accurately the location of new generation and/or demand side resources. However, since timescales for constructing transmission reinforcements are in the five to ten year time horizons for large scale improvements, it will be necessary to identify those projects that can provide the overall best values for the state when considering all of the needs. Since generation expansion assumptions have a major impact on scenario analysis, and there have been some major changes in base generation assumptions since the start of this study, Phase II updated the power flow base case with likely new generation to be installed in the state in the next 5 years based on how far along they are in the current NYISO interconnection process. The updated power flow base case with economic dispatch was used for determination of new Interface Transfer Limits.

3

Transmission system condition assessment

3.1 Transmission system condition assessment

In preparation for the initiation of the Phase II portion of the STARS study a Condition Assessment Working Group was formed to determine the potential long term needs required to address the replacement of aging transmission system.

Subject matter experts were assembled from all the participant companies. The group utilized a high level screening criteria of 70 years for wood pole lines and 90 years for steel pole lines in establishing the potential time frames when transmission facilities would require replacement. It is recognized that an aged based criteria alone is not a sufficient justification for the replacement of assets and that detailed condition assessment analyses would be required prior to justifying a facility for replacement. If more detailed condition assessment information was available it was utilized in lieu of the 70 and 90 year aged based criteria.

The value of having the high-level condition assessment information was to provide input into the development of transmission reinforcement projects in Phase II. Opportunities were identified where it might be prudent to consider a thermal or voltage upgrade rather than simply replace a facility "in-kind" due to condition.

The Condition Assessment Working Group identified the potential need to replace nearly 4700 miles of transmission at operating voltages 115 kV and above over the next 30 years (Figure 3-1). The estimated cost to replace this infrastructure utilizing high-end pro-forma estimates from CARIS is over $25 billion. Figure 3-1 provides a breakdown of these transmission infrastructure needs by company and voltage class.

Figure 3-1 Future transmission infrastructure needs

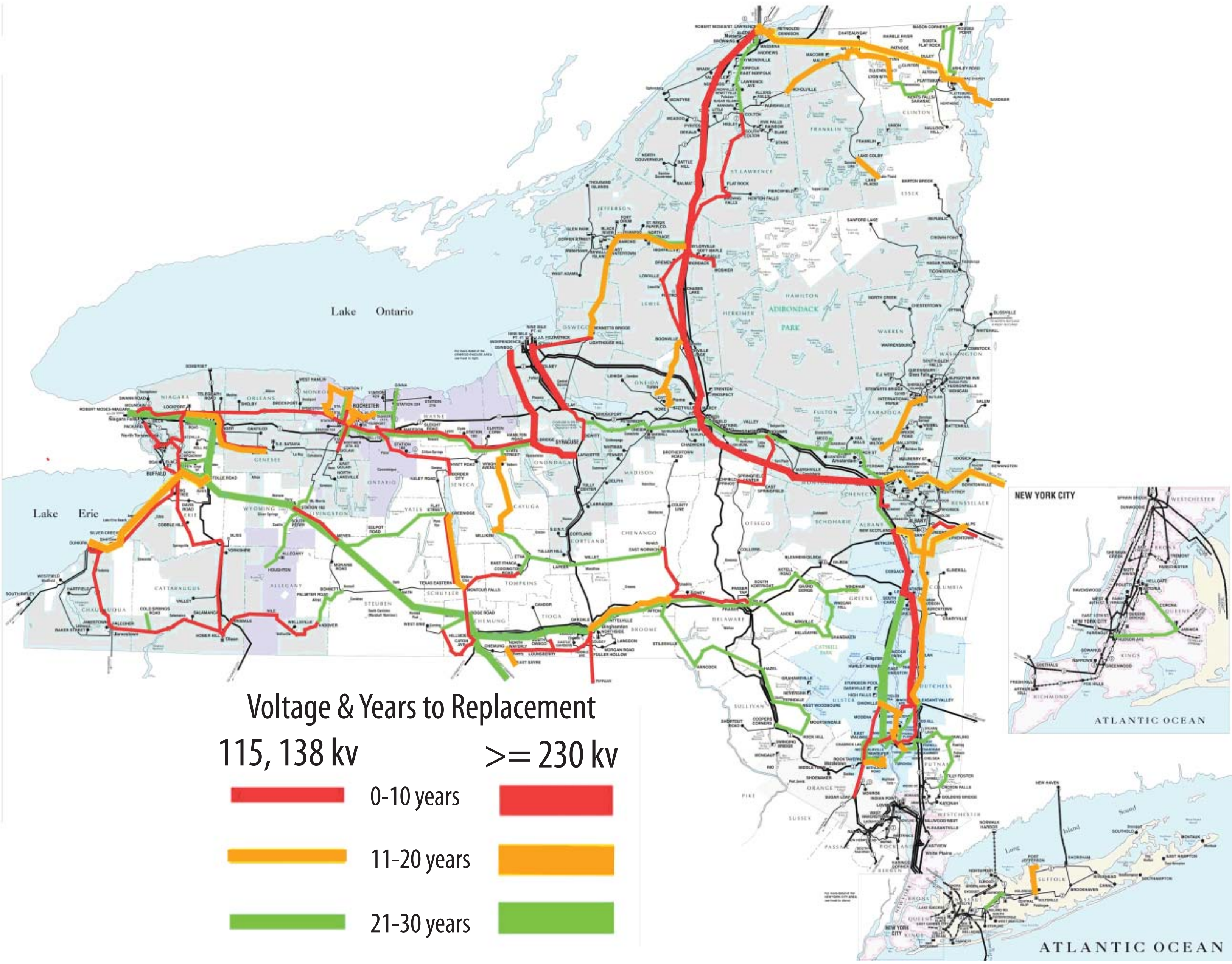
Voltage	Central Hudson	ConEd	LIPA	National Grid	NYPA	NYSEG	O&RU	RGE	Total miles replaced	Total miles
Overhead										
115/138kV	61.4%	0.0%	7.8%	42.5%	46.3%	64.1%	64.4%	87.3%	3,441	7,173
230kV	0.0%	0.0%	0.0%	53.4%	89.1%	99.6%	0.0%	0.0%	794	1,066
345kV	100.0%	0.0%	0.0%	43.8%	0.0%	0.0%	0.0%	0.0%	375	2,624
500kV	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0	5
765kV[1]	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0	155
Total OH system replaced	70.7%	0.0%	7.8%	43.5%	22.3%	52.5%	40.6%	87.3%	4,610	11,024
Underground										
Total UG system replaced	0.0%	11.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	45	602

[1]Lines constructed for but not operated at 765 kV

To highlight the replacement requirements, the STARS Condition Assessment Working Group created an overlay for the New York State Electric System map which depicts the corridors where transmission facility replacement work may be necessary (Figure 3-2).

Figure 3-2 ***New York state transmission condition assessment map***

STARS age-based condition assessment



4

Phase II scope

Phase II scope

4.1 Background

Phase I of the STARS study was completed in January 2010. The results of that study were based on resource capacity, other assumptions and data available at the time the study started in February 2009. Since then, there were substantial new resources proposed in the downstate as well as in the upstate zones. Several projects had completed the interconnection process, entered the class year and completed cost allocation. In the NYISO planning process, acceptance of class year cost allocation suggests a project with high likelihood of realization. In addition to the new resources, there were some transmission improvements (DOE stimulus projects including planned capacitor banks in NYSEG, RGE, NYPA, CHGE and NATIONAL GRID systems, local transmission improvements in LIPA system) that had been previously identified by the NYTOs. It was deemed that this new information, if included in the calculation of LOLE, will result in reduction of transmission needs. Based on the above situation and the information available (as of February 2010), the STARS Executive Committee and the STARS TWG considered it prudent to include the new information and re-compute the transmission MW needs. This is described under Section 4.2 below (Initial Analysis) and culminated in the summer of 2010. Subsequent analysis was performed after this period and included the following activities:

- Evaluation of Aging Infrastructure – Condition Assessment
- Selection of Generation Expansion Scenario
- Include projects recommended by the NYISO Wind Study
- Development of Base Transmission Plan (BTP)
- Economic Analysis of Base Transmission Plan (Production Cost / LBMP Analysis, ICAP Cost Savings)

The findings of these activities are described in subsequent sections of this report. As described previously, the actual expansion of the NYCA transmission grid should be adapted to account for the constantly evolving load growth, location and magnitude of future resource capacity additions, and assumed emergency assistance from neighboring control areas. In Phase I of the study transmission needs required to maintain system reliability were identified. Phase II will address the coordinated upgrade and new transmission infrastructure needs necessary to achieve public policy goals, deliver renewable resources and / or provide economic benefits to the state by relieving known constraints that exist within the system. By considering all of these important objectives the study will result in a holistic evaluation of the potential transmission projects best suited to achieve them.

4.2 Initial Phase II analysis

Initial analysis performed during 2010 included the following generation additions to the 2030 horizon year study models developed in Phase I of the STARS study (See Attachment #1):

- Astoria Energy II in Zone J (550 MW)
- Solar Farm in Zone K (50 MW)

In addition, generation retirements in Zone C (see Section 5.3 for details) were also reflected in the study models. Also included in the study models were the DOE stimulus projects, including planned capacitor bank additions as proposed by the NYTOs. In addition, some minor modeling changes were made to the power flow models based on input provided by the NYISO and NYTOs.

The capacity expansion scenarios assumed in the Phase I study were updated to include the modeling changes described above. The basis used by the STARS TWG for developing the four Scenarios (or book-end possibilities of new resources) is shown in Table 2-1 of the Phase I Report. The above-mentioned generation additions, noted earlier, are in Zones J and K. Because, the premise for Scenario 1 was that 85% of the new generation is to be located downstate, the two major generation projects are already included in Scenario 1 by default. Hence, it was deemed that there was no need to modify the Scenario 1 generation allocation and assumptions or to repeat LOLE calculations. Thus, the generation capacity additions and retirements were used to modify the three remaining Scenarios (Scenarios 2, 3 and 4). The new generation capacity for the horizon year was calculated as follows:

- With 65% capacity credit, the new Solar Farms have effective capacity of 32.5 MW
- Adding the new units and including retirements, reduced the new capacity requirement (Table 2-4, Phase I report) from 5,015 MW to 4,528 MW (=5015-550-32.5+53+42) (See generation expansion and retirement details in Section 5)

The new revised capacity requirement of 4,528 MW for the three Scenarios was allocated according to the Scenario definition in Table 2-1 of Phase I report. For example, in Scenario 3, the additional generation is 4,075 MW (i.e., 90% of 4,528 MW). Further, the additional generation was allocated to each zone in proportion to the zonal load. Generic 250MW units with 6% forced outage rate are assumed for the new generation, unless only smaller amounts are indicated. The new generation units assumed for the three Scenarios are shown in Figure 4-1. The updated scenarios are renamed 2A, 3A and 4A to avoid confusion with the original capacity expansion scenarios.

Figure 4-1 New generation capacity for scenarios 2A, 3A and 4A

Scenario-2A (50% upstate, 50% external)

50 % of requirement		2,264		2,264					**50% of requirement**			2,264	2,264
			Conventional		**Locations for new generator**								
	Load	New gen	Units	MW	Bus name	kV	Units	MW					**Conventional**
ZONE-A	3,123	496	2	500	KINTI345	345	1	250	25%	PJM	ZONES-A&C	1,132	1,132
					DUNKIRK	230	1	250					
ZONE-B	2,365	376	2	500	ROCHESTER	345	2	500	25%	HQ	ZONE-D	1,132	1,132
ZONE-C	3,323	528	2	500	CLAY	345	2	500					
ZONE-D	971	154	0	-	MASS230A	230	0	-					
ZONE-E	1,600	254	1	264	EDIC	345	1	264					
ZONE-F	2,868	456	2	500	ATHENS	345	2	500					
ZONES-TOTAL	14,250	2,264	9	2,264			9	2,264					2,264
TOTAL NEW CAPACITY		2,264									TOTAL	2,264	

Scenario-3A (90% all zones, 10% external low import)

90 % of requirement		4,075		4,075					**10% of requirement**			453	453
			Conventional		**Locations for new generator**								
	Load	New gen	Units	MW	Bus name	kV	Units	MW					**Conventional**
ZONE-A	3,123	312	1	250	KINTI345	345	1	250	3.3%	ISONE	ZONES-F&G	151	151
					DUNKIRK	230	0	-	3.3%	PJM	ZONE-J	151	151
ZONE-B	2,365	236	1	250	ROCHESTER	345	1	250	3.3%	HQ	ZONE-D	151	151
ZONE-C	3,323	332	2	500	CLAY	345	2	500					
ZONE-D	971	97	0	-									
ZONE-E	1,600	160	1	250	EDIC	345	1	250					
ZONE-F	2,868	286	1	250	ATHENS	345	1	250					
ZONE-G	2,948	294	1	250	HURLEY 3	345	1	250					
ZONE-H	782	78	0	-									
ZONE-I	1,753	175	1	75	PL VILLE	345	1	75					
ZONE-J	14,326	1,430	6	1,500	E 13TH ST	345	4	1,000					
					W 49TH ST	345	2	500					
ZONE-K	6,757	675	3	750	RULAND	138	2	500					
					HOLLBROOK	138	1	250					
ZONES-TOTAL	40,816	4,075	17	4,075			17	4,075					453
TOTAL NEW CAPACITY		4,075									TOTAL	453	

Scenario-4A (25% all zones, 75% external high imports)

25 % of requirement		1,132		1,132					**75% of requirement**			3,396	
			Conventional		**Locations for new generator**								
	Load	New gen	Units	MW	Bus name	kV	Units	MW					**Conventional**
ZONE-A	3,123	87	1	250	KINTI345	345	1	250	25%	PJM	ZONES I/J/K	1,133	1,133
ZONE-B	2,365	66	0	-				-					
ZONE-C	3,323	92	1	250	CLAY	345	1	250					
ZONE-D	971	27	0	-				-	50%	HQ	ZONE-D	2,267	2,267
ZONE-E	1,600	44	0	-				-					
ZONE-F	2,868	80	0	-				-					
ZONE-G	2,948	82	0	-				-					
ZONE-H	782	22	0	-				-					
ZONE-I	1,753	49	0	-				-					
ZONE-J	14,326	397	2	500	E 13TH ST	345	1	250					
					W 49TH ST	345	1	250					
ZONE-K	6,757	187	1	128	RULAND	138	1	128					
ZONES-TOTAL	40,816	1,133	5	1,128			5	1,128					3,400
TOTAL NEW CAPACITY		1,128									TOTAL	3,400	

Next, emergency transfer limits for key NYCA interfaces derived in the Phase I study were updated based on the above modeling assumptions. The updated emergency transfer limits were used in the subsequent LOLE analysis on Scenarios 2A, 3A and 4A.

GridView simulations were performed on scenarios 2A, 3A and 4A and the LOLE indices were recalculated. Results are shown in Figure 4-2. The results shows that with 550 MW added to zone J and 32.5 MW effective solar capacity added to zone K, the LOLE indices reduced significantly for all the three scenarios: from 1.68 to 0.96 days/year for Scenario 2A; from 0.20 to 0.08 days/year for Scenario 3A, and from 0.44 to 0.36 days/year for Scenario 4A.

Figure 4-2 Calculated LOLE values for scenarios 2A, 3A and 4A

Horizon year's LOLE (days/year)			
Zones	**Scenario 2A**	**Scenario 3A**	**Scenario 4A**
A	-	-	-
B	0.34	0.03	0.12
C	-	-	-
D	-	-	-
E	0.82	0.06	0.32
F	-	-	-
G	0.80	0.08	0.30
H	0.00	0.00	0.00
I	0.88	0.07	0.30
J	0.97	0.07	0.33
K	1.02	0.08	0.38
NYCA	**0.96**	**0.08**	**0.36**

Since the updated Scenario 3A has an LOLE of 0.08 days/yr, it was deemed that only Scenarios 2A and 4A would need additional transmission capacity for reliability purposes. Using the methodology, described in Phase I report (Section 9.4), a series of sensitivity cases were simulated for Scenarios 2A & 4A. Additional transmission capacities were calculated (based on statistical average peak interface flow value). Results are summarized in Figure 4-3.

Figure 4-3 Additional transfer capability needs (MW)

	Scenario 2	Scenario 2A	Reduction	Scenario 3	Scenario 3A	Reduction	Scenario 4	Scenario 4A	Reduction
I to J	1,135	505	630	386	0	386	424	0	424
Marcy South	435	173	262	15	0	15	257	6	251
F to G	1,171	698	473	187	0	187	399	89	310
UPNY-SENY	1,735	933	803	249	0	249	702	142	560
CE Group	1,460	766	694	150	0	150	1,185	712	473
Central East	1,047	745	302	279	0	279	1,106	750	356
Volney East	1,314	916	398	492	0	492	648	256	392
West Central	265	102	164	316	0	316	192	0	192
Y49Y50	752	499	253	159	0	159	972	719	253
Total East	1,274	499	774	0	0	0	456	0	456
Moses South	0	0	0	0	0	0	228	0	228
HQ-D	0	0	0	0	0	0	550	300**	250
UPNY-CE	1,219	561	658	NA	0	NA	NA	0	NA

** based on HQ-D nonemergency limit of 1,200 MW

Figures 4-2 and 4-3 demonstrate how sensitive resource adequacy is to generation siting. In the generation expansion for Scenario 3A with 90% of the expansion located in the New York control area, the LOLE meets criteria and there is no additional transfer capability needed. For other generation expansion scenarios where more generation is sited upstate or where imports are relied on more heavily the system does not meet established reliability criteria and there is an associated additional transfer capability need, thus a need for more transmission.

4.3 Generation expansion scenario selection

As was discussed in the Phase I portion of the study and as demonstrated in the updated Phase II analyses presented above the identified needs of the transmission system need to be adapted and account for the constantly evolving load growth, location and magnitude of future resource capacity additions and assumed energy assistance from neighboring control areas. Since the generation expansion assumptions have such a significant impact on resource adequacy and potential transmission expansion needs from a reliability perspective the study group sought guidance on the most appropriate assumptions to select for the detailed transmission planning analysis that would be performed in Phase II.

The study group during late spring and early summer of 2010 consulted with the executives of the study group companies as well as the NYISO and PSC staff in determining which generation expansion scenario would be most appropriate to select. By consensus it was agreed to utilize generation expansion scenario 3A in Phase II of the study. It was felt that this scenario represented the most probable view of generation additions. It should be noted that the utilization of this scenario represents a conservative view of potential transmission expansion needs during the studies time horizon since generation is assumed to be added proportional to load growth across the state, with minimal reliance on additional imports, and at a magnitude that maintains a reserve margin level consistent with current requirements.

4.4 Scenario update

Additional updates were made to Scenario 3A assumptions based on discussions between the STARS Executive Committee, STARS TWG and NYISO. These discussions resulted in the following modeling updates to the horizon year study models for Scenario 3A.

- Addition of Hudson Transmission Project (HTP): This is a 660 MW High Voltage Direct Current (HVDC) transmission link between New York City (Zone J) and PJM Interconnection. The PJM Interconnection Service Agreement (ISA) between PJM, Hudson Transmission Partners, L.L.C. and Public Service Electric and Gas Company , specifies that only 320 MW of the rated transmission capacity of the Hudson Transmission Project is available as Firm Transmission Withdrawal Rights (FTWRs), while the remainder is considered Non-Firm Transmission Withdrawal Rights (NFTWRs). The ISA clarifies that if TWRs above the allotted 320MW were to be requested that significant transmission upgrades would be necessary to reliably accommodate increased FTWRs. The STARS study has assumed that transmission upgrades, such as the Branchburg-Roseland-Hudson project proposed in the 2008 through 2010 PJM Regional Transmission Expansion Plans , will be constructed by year 2030, therefore the HTP was modeled to economically flow up to its full rated capacity. At this point the PJM upgrade (Branchburg-Roseland-Hudson project) has been canceled as noted in the published 2011 RTEP, and the HTP utilization may not be fully achievable by year 2030.

- Addition of 4,725 MW of Wind Generation in NYCA (for a total of 6,000 MW): See Section 5.5 of this report. Reference [2] provides additional information on the wind additions.

It should be noted that the above projects replace some of the generic generation assumed in Scenario 3A. Thus, the capacities of generic generators were reduced to keep the total added generation within the NYISO to 4,075 MW as specified by Scenario 3A. The adjustment took into account the typical capacity factors of the wind generation. Figure 4-4 shows details on the generic unit adjustments.

Figure 4-4 New generic generation capacities after scenario 3A update

Zone name	Zone ID	% of total internal MW addition	No. of generic units	Original generic generation capacity (MW)	% of generic generation addition	Original individual unit generic generation capacity (MW)	Individual unit adjustment for adding HTP (MW)	Adjust-memt for 4,725 MW wind additions (MW)	New individual unit capacity (MW)	New total zonal generic generation capacity (MW)
West	A	7.7	1	250	5.5	250	(36)	(26)	187	187
Genessee	B	5.8	1	250	5.5	250	(36)	(26)	187	187
Central	C	8.1	2	500	11	250	(73)	(52)	187	374
North	D	2.4	0	0	0	0	0	0	0	0
Mohawk Valley	E	3.9	1	250	5.5	250	(36)	(26)	187	187
Capital	F	7	1	250	5.5	250	(36)	(26)	187	187
Hudson Valley	G	7.2	1	250	5.5	250	(36)	(26)	187	187
Milwood	H	1.9	0	0	0	0	0	0	0	0
Dunwoodie	I	4.3	1	75	1.7	75	(11)	(8)	56	56
NY City	J	35.1	6	1,500	33.1	250	(219)	(157)	187	1,122
Long Island	K	16.6	3	750	16.6	250	(109)	(78)	187	561
Hydro Quebec	HQ	0	1	151	3.3	151	(22)	(16)	113	113
ISO New England	ISONE	0	1	151	3.3	151	(22)	(16)	113	113
PJM	PJM	0	1	151	3.3	151	(22)	(16)	113	113
Totals		**100**	**20**	**4,528**	**100**		**(660)**	**(473)**		**3,387**

The last column shows the calculated generic unit capacities (3,048 MW within NYCA and 339 MW outside NYCA). Also, the locations of some of the generic units in Zones F, G and J were changed based on the assumptions made in the economic analysis portion of the study. Figure 4-5 shows the updated generator locations. The Scenario 3A case as updated above is designated the Reference Case in the study.

Figure 4-5 Modified generic generator locations after scenario 3A update

	Locations of generic units				NYISO adjusted
	Bus name	**kV**	**Units**	**MW**	
Zone A	KINTIGH	345	1	250	187
	DUNKIRK	230	0	-	
Zone B	ROCHESTER	345	1	250	187
Zone C	CLAY	345	2	500	374
Zone D					
Zone E	EDIC	345	1	250	187
Zone F	NEW SCOTLAND	345	1	250	187
Zone G	ROCK TAVERN	345	1	250	187
Zone H					
Zone I	PLEASANTVILLE	345	1	75	56
Zone J	EAST 13TH ST	345	1	250	249
	GOWANUS N	345	1	250	249
	RAINEY	345	1	250	249
	WEST 49TH ST	345	3	750	374
Zone K	RULAND	138	2	500	374
	HOLBROOK	138	1	250	187
TOTAL			17	4,075	3,048

5

Study assumptions

Study assumptions

Attachment 3 lists the modeling assumptions used in the Phase II study effort (refer to study assumptions matrix). Additional details on some of the more significant assumptions are provided in the following subsections.

5.1 Load levels

When Phase I of the STARS study first began, the most up-to-date load forecast was in the 2008 NYISO Gold Book. Using the published 2018 50/50 non-coincident peak summer load forecast of 37,130 MW, and the corresponding annual growth percentages, the STARS Study horizon year NYCA load level was projected to be 40,816 MW. The STARS TWG is aware that with the latest forecasts, this load level may not be realized in 2030 (Figure 5-1).

Figure 5-1 Load forecast year

NYISO load forecast (all include EE impacts)	STARS equivalent study year using NYISO Gold Book	
	2010 load forecast	2011 load forecast
50/50 coincident summer peak	2035	2036
50/50 non-coincident summer peak	2033	2035
90/100 coincident summer peak	2029	2030

5.2 Planned facilities

Prior to the start of the Phase II study effort, the STARS TWG and the NYISO together identified a set of projects that were deemed to have a high likelihood of being commissioned within New York State within the next 5 years based on how far along they are in the NYISO interconnection process. These projects included the following facilities:

- Astoria Energy II (550 MW)
- LIPA Solar Farm (50 MW)
- Hudson Transmission Project (HTP, 660 MW)

The Bayonne project was not included in the study models because its status was deemed unknown at the time the Phase II study assumptions were finalized.

5.3 Generation retirements

The following generation retirements were included in the Phase II study. This is based on information contained in the 2010 NYISO Gold Book.

- Greenidge 3 (53 MW)
- Westover 7 (aka Goudey, 42 MW)

5.4 Generic generation expansion scenario units

Figure 4-1 shows the original expansion scenario units modeled in the Phase II analysis. The corresponding units in updated Scenario 3A are shown in Figure 4-5.

5.5 Wind generation

In September of 2010 the NYISO released a study titled "Growing Wind" that analyzes in great detail the reliability, economic, environmental, and regulatory aspects of increasing wind generation capacity in New York State. The study outlines three expansion scenarios where New York wind generation capacity is evaluated at 4,250 MW (New York State Renewable Portfolio Standard (RPS) Goal for 2013), 6,000 MW, and 8,000 MW capacity levels. The STARS base system model includes the 6,000 MW of wind generation and associated transmission upgrades necessary to deliver that generation to the bulk power system. Both the 4,250 MW and 8,000 MW wind capacity cases and their associated transmission upgrades were modeled in the sensitivity analysis phase of the STARS study.

Figure 5-2 NYISO nameplate wind generation by zone (MW)

NYISO zone:	West	Genesee	Central	North	Mohawk Valley	Capital	NYC & LI	Total
Base wind capacity:	1,291	281	1,593	1,068	1,647	70	0	5,949

Wind generators are modeled with fixed schedules and have the capability to curtail their output. Each generator is assigned a wind curve that represents historical geographical yearly wind patterns and is scaled to match the nameplate rating of the wind plant. The historical wind curves used were developed by AWS Truewind for the NYISO Wind Study.

The specific projects recommended by the NYISO wind study and included in the study are included in Section 6.6 of the report.

5.6 Transmission system model

The Horizon Year power flow models used in the Phase II study were derived from the Phase I study effort. See Reference [1]. Models were updated to reflect planned facilities, generation retirements, expansion scenario units and wind additions as described in the preceding sections.

5.7 Resource reliability model

The primary tool used for LOLE calculation in this study is GridView software. In this model a full representation of the transmission network (as in the power flow cases including external areas) is used. In addition to the detailed transmission network representation, the GridView model contains various constraints for transmission lines, interfaces, contingency constraints, monitored lines, nomograms and emergency operating procedures.

5.8 Interface limits

Horizon year emergency thermal transfer limits were calculated for key NYCA interfaces with the Base Transmission Plan projects and variations thereof (Trials 9 and 10; See Section 8.3.3). The Central East related interfaces have traditionally been voltage limited, whereas the other interfaces have tended to be thermally limited. So for purposes of this study, voltage transfer limits were only calculated for the Central East related interfaces. The lower of the two limits were used in the subsequent LOLE analysis.

5.9 Fuel forecast

The fuel forecasts used as inputs into the production cost model were developed using the publicly available forecasts made by the Energy Information Administration (EIA) from Spring 2011. The forecasts were adjusted for seasonality and monthly volatility based upon historical patterns in the NYCA.

5.10 HQ model update

The NYCA import limit from the Quebec Chateauguay-Massena single 765 kV interconnection was modeled at 1,380 MW per current NYISO operating criteria, which prevents a single external NYCA source from exceeding the largest internal contingency, in this case Nine Mile Point Station #2 at a projected capacity of 1380 MW. The thermal capability of the Chateauguay substation, with four 765/120 kV transformers placed in service, is approximately 2370 MW. The operating limitation on the Chateauguay-Massena 765 kV line as a single source limited the benefit realized by the Moses South 230 kV to 345 kV upgrades in the STARS Base Transmission Plan.

As part of the production cost analysis a price sensitive model for HQ generation consisting of a thermal generator/load pair was created to produce an equivalent maximum generation amount. Historical HQ imports were used to develop an appropriate energy output pattern for the thermal generator/load pair. Additional details regarding this model are provided in Attachment 4.

5.11 Emissions forecast

The emissions price forecasts were created based upon the most up-to-date regional rules and regulations established at the time of the production cost database update (consistent with NYISO CARIS II 2010). The forecasts were driven largely by the Environmental Protection Agency's Clean Air Transport Rules.

5.12 Economic assumptions

The Replacement Plan for the STARS economic analysis was developed from the 2009 NYISO CARIS Phase I ABB GridView database and model. There were a significant number of changes and updates made to the database in order to align with the STARS assumptions, which are listed in Attachment 3. The major assumptions utilized in the economic database and production cost simulations are outlined below.

- 40,816 MW NYCA Peak Load
- Updated Generation & Transmission from NYISO Queue
  - Astoria Energy II
  - LIPA Solar
  - Hudson Transmission Project
- 4,528 MW of Generation Capacity Expansion
  - 90% Internal to NYCA = 4,075 MW
  - 10% External to NYCA = 453 MW

When adding additional wind generation to reach the 6,000 MW level prescribed in the NYISO Wind Study several adjustments to the case had to be made. First, numerous underlying sub-transmission upgrades had to be constructed to connect the wind generators to the bulk power system without causing overloads. Second, in order to stay true to the assumption of 4,528 MW of generation expansion to meet reliability criteria, generic generation expansion was reduced to accommodate the wind additions. Using a 10% capacity factor for land based wind generation and a 30% capacity factor for offshore, an equivalent amount of capacity was removed from the generic generators.

Upon completion of the model update for the STARS Replacement Plan, the Base Transmission Plan case was created by adding the transmission lines and elements listed in Attachment 7 to the economic database. Both the Replacement Plan and Base Transmission Plan case were simulated for 8,760 hours to simulate a single year of system operation.

6

Development of base transmission plan

Development of base transmission plan

The STARS TWG, selected projects for the Base Transmission Plan (BTP) that satisfied the identified MW needs. These needs included Condition Assessment MW Needs, Reliability MW needs and Unconstrained MW needs which were calculated on an interface basis.

6.1 Condition assessment MW needs

A high level screening criterion was used to identify transmission lines with a higher probability of replacement need based on condition. This was supplemented with a more detailed condition assessment of the National Grid transmission lines based on their assessment performed in 2009/2010. Since this was a screening assessment, no update has been made since the initial condition assessment performed by the study team. As indicated earlier, any decision to move forward with condition refurbishment work would be based on detailed analyses. Section 3 of this report provides a description of the condition assessment methodology. Figure 6-1 provides a summary of the Condition Assessment MW needs by interface. The columns represent transmission lines that meet the selection criteria. Although identified as meeting the criteria, a more detailed analysis of the two Leeds to Pleasant Valley 345 kV lines performed by National Grid indicated that the extent of mitigation only requires replacement of select towers.

Figure 6-1 Condition assessment replacement MW need summary

	Condition assessment needs (values in MW)									
	Pannel to Farminton 115 kV	Kattelville to Jenison 115 kV	East Spring-field to Inghams 115 kV	Rotterdam to Porter 230 kV (1)	Rotterdam to Porter 230 kV (2)	Leeds to Pleasant Valley 345 kV (1)	Leeds to Pleasant Valley 345 kV (2)	Moses to Adirondack 230 kV (1)	Moses to Adirondack 230 kV (2)	Total
West Central	206									**206**
Volney East		110								**110**
Moses South								348	348	**696**
Marcy South										**0**
Central East			80	440	439					**959**
F to G						1,331	1,331			**2,662**
I to J										**0**
I to K										**0**
HQ - D										**0**
CE Group										**0**
UPNY-SENY						1,331	1,331			**2,662**
Total East			80	440	439					**959**

Figures 6-2 through 6-8 provide detailed information for each line of each interface. Lines shaded in red will meet the selection criteria for replacement in 0-10 years. Lines shaded in orange will meet the selection criteria for replacement in 10-20 years. Lines shaded in yellow will meet the selection criteria for replacement in 20-30 years. The summer normal ratings of the orange and red shaded lines are summed to provide the Condition Assessment MW Need for each interface.

Figure 6-2 West Central interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
WEST CENTRAL	STOLE230	230	MEYER230	230	1	430
WEST CENTRAL	STOLE230	230	SHLDN230	230	1	430
WEST CENTRAL	C708 LD	34.5	WOLCOT34	34.5	1	25
WEST CENTRAL	QUAKER	115	MACDN115	115	1	165
WEST CENTRAL	S121 B#2	115	SLEIG115	115	1	150
WEST CENTRAL	CLYDE199	115	SLEIG115	115	1	145
WEST CENTRAL	QUAKER	115	SLEIG115	115	1	150
WEST CENTRAL	ANDOVER1	115	PALMT115	115	1	79
WEST CENTRAL	STA 162	115	S.PER115	115	1	125
WEST CENTRAL	MORTIMER	115	LAWLER-1	115	1	129
WEST CENTRAL	MORTIMER	115	LAWLER-2	115	1	129
WEST CENTRAL	PANNELL3	345	CLAY	345	1	1033
WEST CENTRAL	PANNELL3	345	CLAY	345	2	1033
WEST CENTRAL	STA127	34.5	HOOKRD	115	1	75
WEST CENTRAL	CLYDE199	115	CLTNCORN	115	1	145
WEST CENTRAL	FARMNGTN	34.5	FARMGTN1	115	1	58
WEST CENTRAL	PANNELLI	115	FRMGTN-4	115	1	206
WEST CENTRAL	FRMNGT2	34.5	FRMGTN-4	115	1	58
WEST CENTRAL	S168	12	FRMGTN-4	115	1	56
WEST CENTRAL	CLYDE 34	34.5	CLYDE199	115	1	38
WEST CENTRAL						4658

THERMAL LIMIT 1877 **Replacement MW due to condition assessment: 206**
VOLTAGE LIMIT 1134 **(Sum of Red & Orange RateA)**

Figure 6-3 Volney East interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
VOLNEY EAST	OAKDL345	345	FRASR345	345	1	1255
VOLNEY EAST	OAKDL115	115	DELHI115	115	1	161
VOLNEY EAST	WILET115	115	E.NOR115	115	1	108
VOLNEY EAST	KATEL115	115	JENN 115	115	1	110
VOLNEY EAST	CLAY	345	EDIC	345	1	1301
VOLNEY EAST	CLAY	345	EDIC	345	2	1301
VOLNEY EAST	VOLNEY	345	MARCY T1	345	1	1434
VOLNEY EAST	BRDGPORT	115	PETRBORO	115	1	116
VOLNEY EAST	LTHSE HL	115	BLACK RV	115	1	106
VOLNEY EAST	LTHSE HL	115	E WTRTWN	115	1	116
VOLNEY EAST	TEALL	115	ONEIDA	115	1	116
VOLNEY EAST	OMEGAWIR	34.5	CAMDEN	34.5	1	22
VOLNEY EAST	JA FITZP	345	EDIC	345	1	1434
VOLNEY EAST	W HILL_T	115	ONEIDA	115	1	146
VOLNEY EAST						7726

THERMAL LIMIT 4540 **Replacement MW due to condition assessment: 110**
VOLTAGE LIMIT 3952 **(Sum of Red & Orange RateA)**

Figure 6-4 Central East interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
CENTRAL EAST	E.SPR115	115	INGHAM-E	115	1	80
CENTRAL EAST	EDIC	345	N.SCOT77	345	1	1331
CENTRAL EAST	JORDNVLL	230	ROTRDM.2	230	1	440
CENTRAL EAST	PORTER 2	230	ROTRDM.2	230	1	440
CENTRAL EAST	PORTER 2	230	ROTRDM.2	230	2	439
CENTRAL EAST	INGMS-CD	115	INGHAM-E	115	1	167
CENTRAL EAST	MARCY T1	345	N.SCOT99	345	1	1487
CENTRAL EAST						4384

THERMAL LIMIT **3007**
VOLTAGE LIMIT **2604**

Replacement MW due to condition assessment: **959**
(Sum of Red & Orange RateA)

Figure 6-5 F to G interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
F TO G	LEEDS 3	345	HURLEY 3	345	1	1395
F TO G	BOC 2T	115	N.CAT. 1	115	1	116
F TO G	BOC 2T	115	N.CAT. 1	115	2	116
F TO G	ADM	115	PL.VAL 1	115	1	119
F TO G	BL STR E	115	PL.VAL 1	115	1	119
F TO G	BLUES-8	115	PL.VAL 1	115	1	116
F TO G	LEEDS 3	345	PLTVLLEY	345	2	1331
F TO G	ATHENS	345	PLTVLLEY	345	1	1331
F TO G						4643

THERMAL LIMIT **3485**
VOLTAGE LIMIT **3760**

Replacement MW due to condition assessment: **2662**
(Sum of Red & Orange RateA)

Note: Condition assessment has indicated select structure replacement is needed for the two existing Leeds to Pleasant Valley 345 kV lines.

Figure 6-6 Moses South interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
MOSES SOUTH	JAY12	46	NORTON46	46	1	33
MOSES SOUTH	ALCOA-NM	115	BRADY	115	1	128
MOSES SOUTH	ALLENS F	115	COLTON	115	1	119
MOSES SOUTH	DENNISON	115	ANDRWS-4	115	1	220
MOSES SOUTH	DENNISON	115	LWRNCE-B	115	1	220
MOSES SOUTH	GILPIN B	46	GILPINT	46	1	40
MOSES SOUTH	MASS 765	765	MARCY765	765	1	3975
MOSES SOUTH	MOSES W	230	ADRON B1	230	1	348
MOSES SOUTH	MOSES W	230	ADRON B2	230	1	348
MOSES SOUTH						5431

THERMAL LIMIT **2660**
VOLTAGE LIMIT **1971**

Replacement MW due to condition assessment: **696**
(Sum of Red & Orange RateA)

Figure 6-7 Total East interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
TOTAL EAST	JEFFERSN	500	RAMAPO 5	500	1	1048
TOTAL EAST	HUDSON1	345	B3402 PAR1	345	1	536
TOTAL EAST	LINDEN	230	GOETHALS	230	1	645
TOTAL EAST	WALDWICK	345	SMAHWAH1	345	1	602
TOTAL EAST	WALDWICK	345	SMAHWAH2	345	1	602
TOTAL EAST	HUDSON2	345	C3403 PAR2	345	1	560
TOTAL EAST	LINVFT4	345	COGNTECH	345	1	500
TOTAL EAST	HCOR138	138	BURNS138	138	1	209
TOTAL EAST	SMAH138	138	RAMP138	138	1	249
TOTAL EAST	SMAH138	138	SMAHWAH1	345	1	484
TOTAL EAST	HCOR69	69	WNYA69	69	1	124
TOTAL EAST	MONTVALE	69	BLUHILL	69	1	67
TOTAL EAST	MONTVALE	69	BLUHILL	69	2	67
TOTAL EAST	MONTVALE	69	L491T	69	1	121
TOTAL EAST	SMAH69	69	HILB69	69	1	153
TOTAL EAST	HCOR34	34.5	PEARL34	34.5	1	20
TOTAL EAST	CRESSKIL	69	SPARKILL	69	1	131
TOTAL EAST	PLAT T#3	115	GRAND IS	115	1	262
TOTAL EAST	COOPC345	345	ROCK TAV	345	2	1554
TOTAL EAST	NEPTCONV	345	NWBRG	345	1	0
TOTAL EAST	COOPC345	345	MDTN TAP	345	1	1464
TOTAL EAST	FRASR345	345	GILB 345	345	1	1428
TOTAL EAST	E.SPR115	115	INGHAM-E	115	1	80
TOTAL EAST	W.WDB115	115	W.WDBR69	69	1	48
TOTAL EAST	EDIC	345	N.SCOT77	345	1	1331
TOTAL EAST	JORDNVLL	230	ROTRDM.2	230	1	440
TOTAL EAST	PORTER 2	230	ROTRDM.2	230	1	440
TOTAL EAST	PORTER 2	230	ROTRDM.2	230	2	439
TOTAL EAST	INGMS-CD	115	INGHAM-E	115	1	167
TOTAL EAST	MARCY T1	345	N.SCOT99	345	1	1487
TOTAL EAST						15258

THERMAL LIMIT 6696
VOLTAGE LIMIT 6270

Replacement MW due to condition assessment: **959**
(Sum of Red & Orange RateA)

Figure 6-8 UPNY-SENY Open interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
UPNY-SENY OPEN	CTNY398	345	PLTVLLEY	345	1	1195
UPNY-SENY OPEN	LEEDS 3	345	HURLEY 3	345	1	1395
UPNY-SENY OPEN	COOPC345	345	ROCK TAV	345	2	1554
UPNY-SENY OPEN	BOC 2T	115	N.CAT. 1	115	1	116
UPNY-SENY OPEN	BOC 2T	115	N.CAT. 1	115	2	116
UPNY-SENY OPEN	ADM	115	PL.VAL 1	115	1	119
UPNY-SENY OPEN	BL STR E	115	PL.VAL 1	115	1	119
UPNY-SENY OPEN	BLUES-8	115	PL.VAL 1	115	1	116
UPNY-SENY OPEN	LEEDS 3	345	PLTVLLEY	345	2	1331
UPNY-SENY OPEN	ATHENS	345	PLTVLLEY	345	1	1331
UPNY-SENY OPEN	COOPC345	345	MDTN TAP	345	1	1464
UPNY-SENY OPEN	W.WDB115	115	W.WDBR69	69	1	48
UPNY-SENY OPEN						8904

THERMAL LIMIT 5124
VOLTAGE LIMIT 6528

Replacement MW due to condition assessment: **2662**
(Sum of Red & Orange RateA)

Note: Condition assessment has indicated select structure replacement is needed for the two existing Leeds to Pleasant Valley 345 kV lines.

6.2 Reliability MW needs

The STARS methodology to determine reliability needs requires a resource adequacy calculation of each of the generation expansion scenarios. This was performed in Phase I and in Phase II for scenarios 2A, 3A and 4A. Reliability based MW needs would then be determined on an interface basis as the increase in emergency transfer capability needed to insure reliability criteria are met. Based on the selection of Scenario 3A (see section 4), there are no Reliability MW Needs for the Base Transmission Plan.

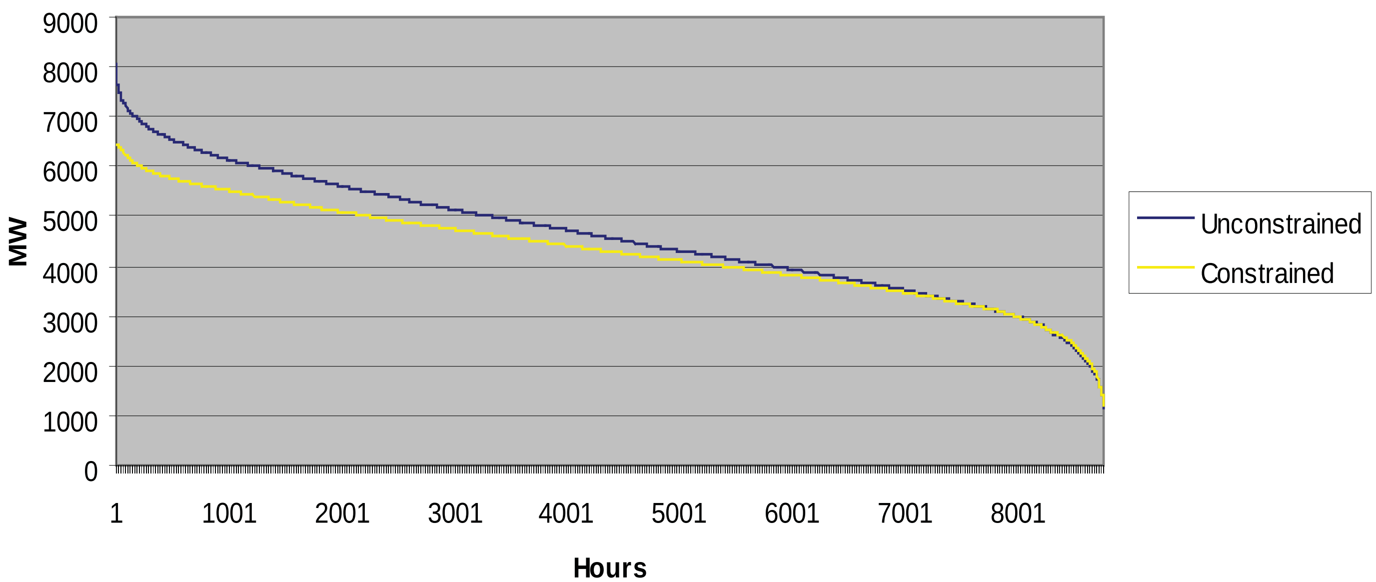
6.3 Unconstrained MW needs

An unconstrained system model was used to determine economic dispatch needs on an interface basis. In an unconstrained system all transmission limits are ignored resulting in a free flowing model. For this unconstrained case, the following was assumed:

- 6000 MW wind case
- All NYCA constraints removed
- Adjust HQ import schedule based on added capability of 2267 MW
- Added new 770 MW PJM-Zone J tie (free flow)
- Added new 363 MW PJM-Zone K tie (free flow)

Load duration curves of the unconstrained and constrained interface flow were developed. The following is an example for Total East (the remainder of the load duration curves can be found in Attachment #5).

Figure 6-9 *Load duration curve for Total East*



The Unconstrained MW Need value for the interface is calculated as the difference between the 100% unconstrained and the constrained. For Total East, the unconstrained value for 100% is 8,033 MW. The constrained value is 6,425 MW. Based on this, the Unconstrained MW Need is 1,608 MW. This indicates that the interface capability could be increased by 1,608 MW and still provide additional value toward lowering statewide production costs. The summary for all of the interfaces in the study is included in Figure 6-10.

Figure 6-10 Unconstrained MW need summary

	Unconstrained	Constrained	MW Need
WEST CENTRAL-OP	2334	1425	909
DYSINGER EAST-OP	2960	2550	410
Volney East-OP	5040	4001	1039
MOSES SOUTH-OP	2639	2237	401
TOTAL EAST	8033	6425	1608
CENTRAL EAST	4012	2800	1212
UPNY Seny-OP	8835	5800	3035
UPNY-ConEd-OP	6119	4059	2060
Spr/Dunwoodie So.-OP	5902	4866	1036
MILLW-SOUTH-OP	6797	5776	1021

6.4 Total MW need

The total MW need was calculated as the sum of the Condition Assessment MW Need, the Reliability MW Need and the Unconstrained MW Need for each interface (Figure 6-11). The total MW need becomes a target for the Base Transmission Plan project selection.

Figure 6-11 Total MW need summary by interface

	Condition assessment need	Scenario No. 3A LOLE need	Unconstrained need	Total need
West Central	206	0	909	1115
Dysinger East	0	0	410	410
Volney East	110	0	1039	1149
HQ - D	0	0	0	0
Moses South	696	0	401	1097
Total East	959	0	1608	2567
Central East	959	0	1212	2171
UPNY-SENY	2662	0	3035	5697
Marcy South	0	0	0	0
UPNY-ConEd	0	0	2060	2060
I to K (Y49/Y50)	0	0	0	0
PJME-J	0	0	0	0
PJME-K	0	0	0	0

6.5 Base transmission plan project selection

The STARS TWG, selected projects for the Base Transmission Plan (BTP) that satisfied the identified Total MW needs. This selection process provides for a high level first cut in terms of satisfying identified needs. The addition of transmission capacity occurs in large scale quantities. Although capacity ratings for new transmission lines can be fine tuned with the selection of the conductor size, the decision to add a transmission line introduces a step change for an interface. A "Delta" is identified for each project that identifies whether the proposed projects provide more capacity or less capacity, as measured by the increased thermal capability, than the identified need. A positive delta indicates that the proposed projects do not fully meet the identified need potentially leaving benefits unrealized. A negative delta indicates that the proposed project provides greater thermal capability than what was identified in the unconstrained case potentially resulting in headroom across the interface. It is recognized that transmission capacity changes for a line that crosses an interface and interface operating limits do not necessarily have a linear relationship. The following describes the project selection process results:

6.5.1 West Central

West Central has a Condition Assessment MW need of 206 MW and an Unconstrained MW need of 909 MW. The Condition Assessment need is met with the rebuild of the Pannell to Farmington 115 kV Line.

Figure 6-12 West Central condition assessment project

Condition assessment project	CA need	Project capacity	Delta
(1) 115 kV Line Pannell to Farmington Rebuild (rating = 206 MW)	206	206	0

The Unconstrained MW need could be met with the reconductoring of four 115 kV transmission lines.

Figure 6-13 West Central unconstrained projects

Unconstrained upgrade project	Unconstrained	Net Project capacity	Delta
(1) 115 kV Line Mortimer to Hook Road #1, reconductor with 1033 ACSR	909	1284	-375
(1) 115 kV Hook Road to Elbridge #7, reconductor with 1033 ACSR			
(1) 115 kV Mortimer to Elbridge #2, reconductor with 1033 ACSR			
(1) 115 kV Line Geneva to Elbridge #15, reconductor with 1033 ACSR			

6.5.2 Dysinger East

Dysinger East has an Unconstrained MW need of 410 MW. The Unconstrained MW need could be met with the reconductoring of three 115 kV transmission lines.

Figure 6-14 Dysinger East unconstrained project

Economic upgrade project	Unconstrained	Net Project capacity	Delta
(1) 115 kV Lines Lockport to Mortimer (#111, 113 and 114), reconductor with 795 ACSR	410	273	137

6.5.3 Volney East

Volney East has a Condition Assessment MW need of 110 MW and an Unconstrained MW need of 1039 MW. The Condition Assessment need could be met with the rebuild of the Kattelville to Jenison 115 kV Line.

Figure 6-15 Volney East condition assessment project

Condition assessment project	CA need	Project capacity	Delta
(1) 115 kV Line Kattelville to Jenison Rebuild (rating = 110 MW)	110	110	0

The Condition Assessment MW need and Unconstrained MW need could be met by replacing the Kattelville to Jenison 115 kV Line with a new 345 kV Line from Oakdale to Fraser.

Figure 6-16 Volney East unconstrained project

Unconstrained upgrade project	Unconstrained	Net Project capacity	Delta
(1) 345 kV Line Oakdale to Fraser (replace Kattelville to Jenison 115 kV)	1039	1390	-351

The Oakdale to Fraser Line would reuse the right of way from Kattelville to Jenison and have a summer normal rating of 1500 MW. The Net Project Capacity of 1390 MW accounts for the 110 MW decrease in capacity associated with not building the Condition Assessment Project.

6.5.4 Moses South

Moses South has a Condition Assessment MW need of 696 MW and an Unconstrained MW need of 401 MW. The Condition Assessment need could be met with the rebuild of the two 230 kV lines from Moses to Adirondack to Porter.

Figure 6-17 Moses South condition assessment project

Condition assessment project	CA need	Project capacity	Delta
(2) 230 kV Lines Moses to Adirondak to Porter Rebuild (rating = 348 MW each)	696	696	0

The Unconstrained MW need could be met by replacing the 230 kV lines from Moses to Adirondack to Porter with two 345 kV lines from Moses to Marcy.

Figure 6-18 Moses South unconstrained projects

Unconstrained upgrade project	Unconstrained	Net Project capacity	Delta
(2) 345 kV Lines Moses to Marcy Replace Moses to Porter 230 kV	401	2304	-1903

The Moses to Marcy lines would reuse the right of way from Moses to Adirondack to Porter and have a summer normal rating of 3000 MW. The Net Project Capacity of 2304 MW accounts for the 696 MW decrease in capacity associated with not building the Condition Assessment Project.

6.5.5 Total East and Central East

Total East and Central East both share the same Condition Assessment MW need of 959 MW. The Unconstrained MW need for Total East is 1608 MW and the Unconstrained MW need for Central East is 1212 MW. The Condition Assessment need could be met with the rebuild of the two 230 kV lines from Porter to Rotterdam and the 115 kV line from East Springfield to Inghams.

Figure 6-19 Total East and Central East condition assessment projects

Condition assessment project	CA need	Project capacity	Delta
(2) 230 kV Lines Porter to Rotterdam Rebuild (rating = 440 MW each)	880	880	0
(1) 115 kV East Springfield to Inghams Rebuild (rating = 80 MW)	80	80	0

The Unconstrained MW need could be met by replacing the 230 kV lines from Porter to Rotterdam with one 345 kV lines from Marcy to Leeds.

Figure 6-20 Total East and Central East unconstrained projects

Unconstrained upgrade project		Unconstrained	Net Project capacity	Delta
(1) 345 kV Line Marcy to Leeds Replace Porter to Rotterdam 230 kV	Total East	1608	620	988
	Central East	1212	620	592

The Marcy to Leeds lines would reuse the right of way from Porter to Rotterdam and have a summer normal rating of 1500 MW. The existing parallel 345 kV lines in this corridor allows for the replacement of two 230 kV lines with a single 345 kV line from a transmission security perspective. The Net Project Capacity of 620 MW accounts for the 880 MW decrease in capacity associated with not building the Condition Assessment Project associated with the two 230 kV lines from Porter to Rotterdam.

6.5.6 UPNY-SENY

UPNY-SENY has a Condition Assessment MW need of 2662 MW and an Unconstrained MW need of 3035 MW. The Condition Assessment need could be met with the rebuild of the two Leeds to Pleasant Valley 345 kV lines. It should be noted that a complete rebuild is not needed for this project. Although identified as meeting the criteria, a more detailed analysis of the two Leeds to Pleasant Valley 345 kV line performed by National Grid indicated that the extent of mitigation may only include replacement of select towers.

Figure 6-21 UPNY-SENY condition assessment project

Condition assessment project	CA need	Project capacity	Delta
(2) 345 kV Lines Leeds to Pleasant Valley Rebuild (rating = 1331 MW each)	2662	2662	0

The Unconstrained MW need could be met by adding a third 345 kV line from Leeds to Pleasant Valley.

Figure 6-22 UPNY-SENY unconstrained projects

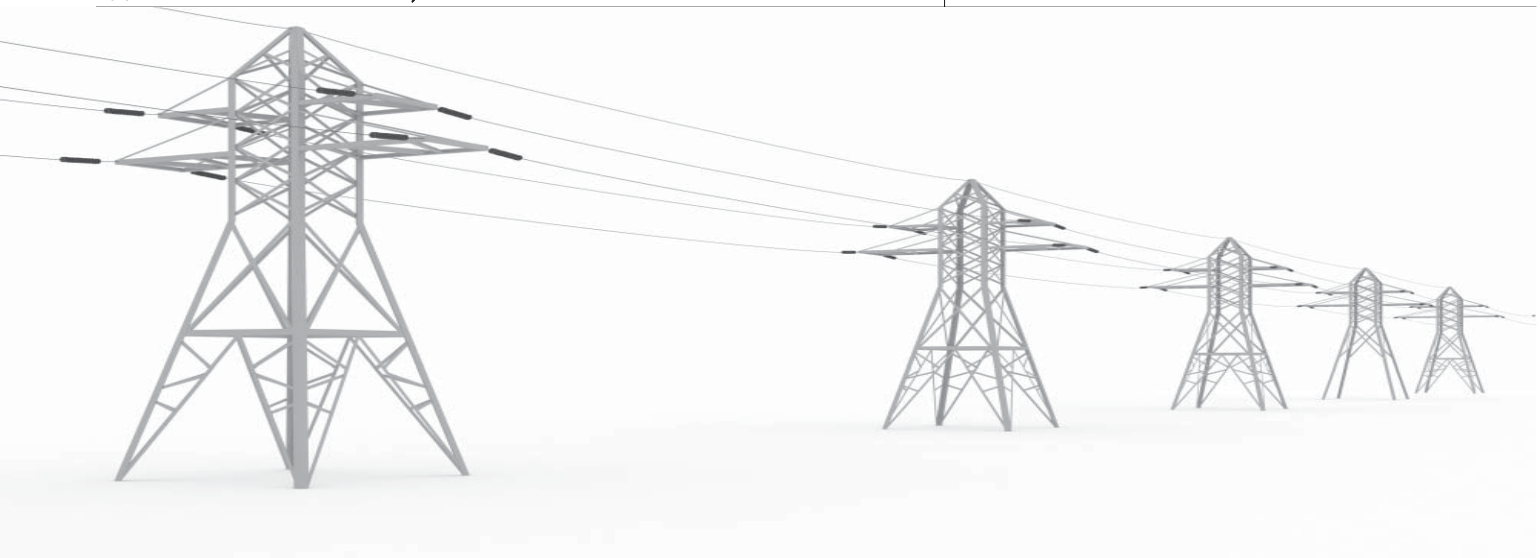
Unconstrained upgrade project	Unconstrained	Net Project capacity	Delta
(1) 345 kV Line Leeds to Pleasant Valley Add Third Line	3035	1500	1535

6.5.7 UPNY-ConEd

UPNY-Con Ed has an Unconstrained MW need of 2060 MW. The Unconstrained need could be met with the addition of a second 345 kV Line from Rock Tavern to Ramapo, a 900 MW DC Line from Pleasant Valley to Sprainbrook, and a 600 MW DC Line from Pleasant Valley to Ruland Road.

Figure 6-23 UPNY-ConEd unconstrained projects

Unconstrained upgrade project	Unconstrained	Net Project capacity	Delta
(1) 345 kV Line Rock Tavern to Ramapo New Line	2,060	3,000	-940
(1) 900 MW DC Line Pleasant Valley to Sprainbrook New Line			
(1) 600 MW DC Line Pleasant Valley to Ruland Road New Line			



6.6 Wind deliverability projects

The NYISO Wind Study which was completed in September of 2010 analyzed the impact of the integration of varying amounts of winds resources ranging from a total of 3,500 MW to 8,000 MW. The primary finding of the report was that wind energy can supply reliable clean energy at a very low production cost to the New York power grid. While the study showed that the addition of wind generation to the resource mix resulted in significant reduction in production costs, the reduction would have been even greater if transmission constraints between upstate and downstate were eliminated. In addition the study determined that almost 9% of the potential upstate wind energy production would be "bottled" or not deliverable because of local transmission limitations. The study identified feasible sets of transmission facility upgrades that would greatly reduce or eliminate the transmission limitations. It should be noted that in many cases the transmission facilities that were analyzed for upgrade have also been identified as potentially requiring replacement based on condition assessment. Figure 6-24 provides a summary listing of projects that were included in the STARS Base Transmission Plan and all of the trials. The wind generators added to create the 8,000 MW wind case were primarily downstate offshore generators that resulted in no significant increases in bottled wind energy due to transmission congestion, therefore no additional transmission upgrades were required. Additional details on the wind projects are included in Attachment 2.

Figure 6-24 Wind deliverability upgrade projects

Transmission path or device	Voltage level	Upgrade
Moses-Willis	230 kV	Tower Reconfiguration
Canandaigua-Hillside& Hillside-Watercure	230 kV	Tower Reconfiguration
Oakdale-Fraser & Oakdale-Lafayette[1]	230 kV	Tower Reconfiguration
Montour Falls-Hillside	115 kV	Conductor
Hillside-North Waverly	115 kV	Conductor
Canandaigua-Avoca-Hillside	230 kV	Conductor
(2) Plattsburgh	230/115 kV	Transformers
Willis-Plattsburgh	230 kV	Conductor
Delhi-Colliers	115 kV	Conductor
Black River-Taylorville-Lowville	115 kV	Conductor
Bennett-Howard-Bath-Montour	115 kV	Conductor
Bennett-Moraine-Meyer	115 kV	Conductor
Moses-Willis	230 kV	Conductor
Lighthouse Hill-Mallory	115 kV	Conductor
Coffeen Street-East Watertown Coffeen Street-Black River Lyme Tap –Coffeen Street	115 kV	Conductor & Towers
Meyer-Eel Pot Rd-Ecogen-Flat St-Greenidge	115 kV	Conductor
Plattsburgh	230/115 kV	Transformers
Taylorville-Boonville	115 kV	Conductor & Terminals
Black River-North Carthage Black River-Taylorville North Carthage-Taylorville	115 kV	Conductor
Coffeen Street-Black River	115 kV	Conductor & Station
Indian River-Black River	115 kV	Bus & Station Connections
Rockledge Tap-Lyme Tap-Coffeen St Coffeen St-Black River	115 kV	Conductor
Coffeen Street-Adirondack	230 kV	New Circuit

[1]This project is currently under development.

6.7 Base transmission cost estimate

The cost estimate for most of the components of the Base Transmission Plan was based on pro-forma low, mid and high values of cost per mile from CARIS. Values were calculated in 2010 dollars. Line lengths represent routes along existing rights of way. In some cases, notably the third Leeds to Pleasant Valley Line and the second Rock Tavern to Ramapo Line, values were based on more detailed cost estimates. For the HVDC projects, values were based on discussions with vendors and comparisons to recent projects. Although costs estimates were calculated at the low, mid and high range values, only the mid range value was used in the economic analysis. The cost estimate for the Base Transmission Plan and the subsequent Trials (see Section 7 for information on Trials) is provided in Attachment #6.

Cost estimates were also developed for Replacement-in-Kind projects. For example, it was identified in Section 6.5.3 that the Oakdale to Fraser 345 kV Line will meet the Condition Assessment MW needs of Volney East, eliminating the need to rebuild the Kattelville to Jennison 115 kV Line. The cost estimate of the rebuild of the Kattelville to Jennison 115 kV line was calculated as a Replacement-in-Kind project. The net cost of the Volney East project is the cost estimate of the Oakdale to Fraser 345 kV Line minus the cost of the Kattelville to Jennison 115 kV Replacement-in-Kind project.

The economic analysis of the Base Transmission Plan (see Section 7) calls for a one-year analysis in the year 2030. The following was assumed for determining the costs in the year 2030:

- As studied the construction of the Base Transmission Plan would start in 2021 and be completed in 2030 with levelized construction costs over the 10 years. It is conceivable that project development could be advanced if it is warranted.
- Inflation through 2030 is 2% per year
- Depreciation is a straight line over 60 years.
- A carrying charge of 20% is applied to the depreciated "rate base" in 2030

Figure 6-25 Base transmission plan cost component summary ($M)

	Total	Replacement plan	Incremental	Carrying charge
Moses to Marcy	1035	842	193	48
Marcy to New Scotland	356	105	251	62
New Scotland Bus Upgrade	30	0	30	7
New Scotland to Leeds	96	0	96	24
Leeds to Pleasant Valley	195	0	195	48
Rock Tavern to Ramapo	113	0	113	28
Oakdale to Fraser	205	31	174	43
Pleasant Valley to Sprainbrook	411	0	411	102
Pleasant Valley to Ruland Road	946	0	946	235
115 kV Upgrades	514	514	0	0
BTP Total	3900	1492	2409	597
Sprainbrook to Ruland Road	535	0	535	133

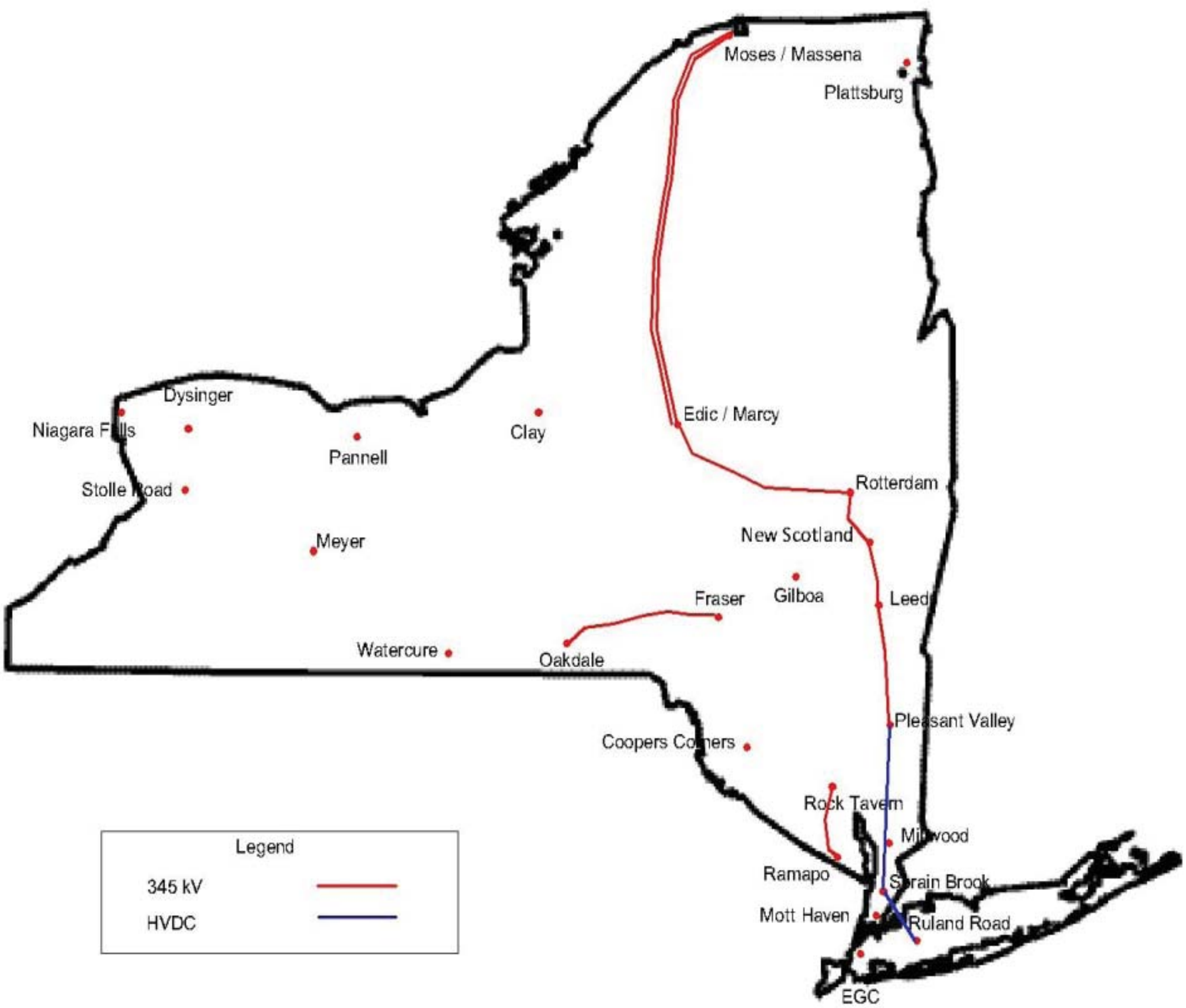
The New Scotland 345 kV Bus upgrade project is included in the Base Transmission Plan because it includes both the Marcy to New Scotland project and the New Scotland to Leeds project. Trials discussed in Section 7 include the New Scotland 345 kV Bus upgrade project only if both the Marcy to New Scotland project and the New Scotland to Leeds Project are included in the trial.

The Sprainbrook to Ruland Road project is a subset of the Pleasant Valley to Ruland Road project. This is used in Trial 5 as discussed in Section 7.

The cost estimates in Figure 6-25 do not include the costs for the Wind Deliverability Projects discussed in Section 6.6. The approximate cost of these upgrades ranges from $75 million to $325 million, depending upon the scope of the upgrades constructed.

A view of the location of the proposed Base Transmission Plan lines is included in Figure 6-26 shown below.

Figure 6-26 *Base transmission plan project locations*



7

Economic Analysis - Production Cost and Locational Based Marginal Price Savings

Economic Analysis - Production Cost and LBMP Savings

7.1 Economic analysis methodology

The proposed transmission projects included in the STARS Base Transmission Plan each serve to promote the transfer of energy throughout the New York Control Area. Projects, taken as individuals or in combinations, can provide varying amounts and types of benefits, which can be estimated through the forecasting, modeling, and the simulation of the electricity market. The primary benefit metric used to measure these economic benefits is system production costs. Production costs include the total cost that generators within a region incur in order to serve the energy demand while simultaneously maintaining system reliability. These can include fuel costs, maintenance costs, and emissions costs. The minimization of production cost is the primary objective function utilized in the linear programs that commit and dispatch energy in both the Real-Time and Day-Ahead Electricity Markets. Reduction in production costs generally provide a good indication of the societal benefits also realized when making a change to system topology.

7.2 Economic analysis assumptions

The Replacement Plan for the STARS economic analysis was developed from the 2009 NYISO CARIS Phase I ABB GridView database and model. The study economic assumptions are described in greater detail in Section 5.12 of the report as well as Attachment 3.

The production cost and LBMP savings estimates reflect a single year value which are estimated to represent a horizon year value of the year 2030. In addition, the annual carrying charges for the transmission investment, new and incremental investment, are for the same horizon year. As such the benefit/cost ratios that are provided in this report represent a one year snapshot which approximates the methodology included in CARIS.

It should be noted that the LBMP values that are provided are "non-adjusted" values. Since these values represent a forecasted value estimated to be approximately the year 2030 no attempt has been made to adjust them for the impacts of any future bilateral contracts or Transmission Congestion Contracts (TCCs) since it would be extremely difficult to estimate. Therefore ratepayer impacts will likely vary due to these among other factors.

7.3 Base transmission plan production cost & LBMP results

With a full year of simulation data from the Replacement Plan and Base Transmission Plan case the economic impacts of the transmission projects can be evaluated. The primary metric of production cost, which includes generator fuel & maintenance costs, import costs, and emissions costs for the New York system, is used to determine potential economic benefits. A secondary metric of LBMP payments by load can also be used. Figure 7-1 was pulled from Attachment 7 and shows the production and LBMP cost results for the Replacement Plan and Base Transmission Plan case and the resulting savings.

Figure 7-1 Reference case production cost results (nominal $)

STARS case	Production cost (M$)	Import cost (M$)	Emissions cost (M$)	Total NYISO production cost (M$)	Load LBMP payment (M$)
Replacement Plan	7,996	1,084	2,451	11,531	23,026
Base Transmission Plan	7,823	1,069	2,439	11,332	22,917
Base Transmission Plan Savings	172	14	12	199	109

The Base Transmission Plan provides a $199M annual decrease in production costs and a $109M annual decrease in Load LBMP Payments in the New York Control Area. This benefit is a direct result of freeing bottled economic energy throughout and into the state. The improved energy transfer can be seen in the utilization of the Base Transmission Plan elements that were added to the Replacement Plan, as shown in Figure 7-2. When reviewing the loading percentages for the BTP elements, it is important to note that for a line with a parallel circuit, the maximum flows on either of the circuits will be limited to the lowest rating of the two by the linear program optimization as part of the transmission security analysis. This could result in a reduced loading factor on one of the BTP elements being studied and was considered when analyzing the results.

Figure 7-2 Base transmission plan element utilization

From bus	To bus	Loading factor (%)
LEEDS 3	PLTVLLEY	43.1
JORDNVLL	PRINCETW	37.5
MARCY T1	JORDNVLL	35.2
ROCK TAV	RAMAPO	35.2
N.SCOT77	LEEDS 3	34.0
PRINCETW	ROTRDM.2	30.3
PRINCETW	ROTRDM.2	30.3
PRINCETW	N.SCOT99	22.7
CHASES L	MARCY T1	19.1
FRASR345	OAKDL345	18.9
PLTVLLEY	RULND RD	16.6
ADRON B2	EDIC	15.2
MOSES W	ADRON B2	12.9
ADRON B1	CHASES L	11.8
MOSES W	ADRON B1	11.8
PLTVLLEY	SPRBROOK	4.8

Not only did the Base Transmission Plan allow energy to flow more economically through the state it also allowed more inexpensive energy to flow into the state, as evidenced by the increase in import energy shown in Figure 7-3.

Figure 7-3 Replacement plan and base transmission plan import energy

External Interface	Replacement Plan Import Amount (MWh)	BTP Import Amount (MWh)	(BTP - Replacement) Import Amount (MWh)
IESO	-947,861	-437,004	510,857
Neptune	3,230,650	3,064,617	-166,034
HQ	4,110,265	5,214,219	1,103,953
CSC	861,862	805,611	-56,250
PJM	876,484	-220,716	-1,097,200
ISO-NE	1,533,988	1,313,402	-220,586
Total	9,665,388	9,740,128	74,741

There is a $14 million annual import cost decrease in the NYISO while increasing the actual amount of energy that is imported by about 75 GWh. The Base Transmission Plan permits more energy to flow from HQ and Ontario which is replacing more expensive imports from PJM and ISO New England.

It is also helpful to see where the savings (in red in Figure 7-4) is occurring within the state when the Base Transmission Plan is applied to the Replacement Plan, shown in the NYISO Zonal Savings Summary. As one can see, the majority of savings accrues to downstate locations.

Figure 7-4 NYISO zonal savings summary

Savings Due to the Base Transmission Plan by NYISO Zone and Import Area, Delta (BTP – Replacement)

Region/Area	Load LBMP Payment (M$)	Generation (MWh)
West	18	285
Genessee	12	31
Central	17	438
North	14	221
Mohawk Valley	14	36
Capital	14	333
Hudson Valley	(17)	(182)
Millwood	(7)	(0)
Dunwoodie	(14)	(16)
NYCity	(108)	(1,149)
Long Island	(51)	(828)
NYISO Total	(109)	(831)

( ) Savings indicated in red

As described in detail in Section 6 of the report the annual carrying costs of the Base Transmission Plan are estimated to be $597 M. The annual benefits of the full Base Transmission Plan as measured in production cost savings shown in Figure 7-1 are estimated to be $199 M. Therefore, from a strict economic perspective the entire Base Transmission Plan cannot be justified at this time solely from a production cost savings economic perspective. However, components of the this Plan are justified in response to other objectives such as reliability, aging infrastructure and improved integration of renewable resources.

For the purposes of specifically identifying purely economic projects in the plan the STARS TWG developed project trials which are described in more detail in subsequent sections of the report.

7.4 Development of transmission trials

While the primary production cost metric presented above provides a good indication of the economic benefits of the entire Base Transmission Plan, more information is required to choose subsets of the BTP for further study. A good indicator of how the Base Transmission Plan addresses transmission bottlenecks in the state is the Dollar Demand Congestion metric. This metric provides information regarding which transmission paths are causing increased production costs in New York. Details of the formulas used to calculate the metric can be found in NYISO OATT Attachment Y and the NYISO CARIS I 2011 Final Report.

Figure 7-5 shows the Dollar Demand Congestion for the Replacement Plan prior to the addition of the Base Transmission Plan. It should be noted that the Demand Congestion figures include results for not only the base set of study assumptions but for a number of sensitivities which are described in greater detail in Section 7.6 of the report.

Figure 7-5 Replacement plan demand congestion ($M annually)

	Contingency	Athens to Pleasant Valley	Pre Contingency		Gowanuss	Dunwoodie	Quenbrg_Verne	Pre Contingency	Marcy	Mothaven	Kinti Roch	Pre Contingency
STARS Scenario	Constraint	Leeds to Pleasant Valley	Greenwood	Central East	Gowanuss	Dunwoodie	E179ST 15055SR	LIPA Cable	Coopers Frasier	Rainey	Niag Roch	Dunwoodie
Reference Case	Replacement	993	35		22	22	20					
High Fuel Forecast	Replacement	1,275	38	28	25	34						
8000 MW Wind	Replacement	971	38	17	18		17					
4250 MW Wind	Replacement	786	32		28	19	23					
Shift 1000MW Upstate	Replacement	1,289	29		33		28	19				
Shift 1000MW Downstate	Replacement	856	40		18	21	17					
High Emissions	Replacement	2,355			47	239		162		72		

The red, orange, and yellow highlighted cells represent the first, second, and third rankings for the elements with the highest demand congestion in the Replacement Plan. Based on these rankings it can be concluded that the Leeds to Pleasant Valley transmission path currently produces the greatest congestion in the state. The Base Transmission Plan addresses Leeds-Pleasant Valley congestion as well as potential congestion in the paths up-stream and downstream to it. Figure 7-6 shows the Dollar Demand Congestion values after the Base Transmission Plan has been applied to the Replacement Plan.

Figure 7-6 Base transmission plan demand congestion ($M annually)

	Contingency	Athens to Pleasant Valley	Pre Contingency		Gowanuss	Dunwoodie	Quenbrg_Verne	Pre Contingency	Marcy	Mothaven	Kinti Roch	Pre Contingency
STARS Scenario	Constraint	Leeds to Pleasant Valley	Greenwood	Central East	Gowanuss	Dunwoodie	E179ST 15055SR	LIPA Cable	Coopers Frasier	Rainey	Niag Roch	Dunwoodie
Reference Case	BTP	20	45			48			73	37		
High Fuel Forecast	BTP		46			71			86	58	24	
8000 MW Wind	BTP		44						75	25	14	24
4250 MW Wind	BTP		37			35	19		26	22		
Shift 1000MW Upstate	BTP	53	35			47			90	48		
Shift 1000MW Downstate	BTP		44			44			66	33	16	
High Emissions	BTP	87				172		144	107	112		

The results of the purely economic analysis of the base transmission plan suggested that at a high level the full plan would not be justified solely on a production cost savings basis. As such the STARS TWG utilized the demand congestion data described in detail above as well as the element utilization information included in Figure 7-2 to help guide the development of transmission plan trials that were economically justified. The study group recognized that there were many permutations and combinations of projects that could be analyzed and as such agreed to evaluate a limited number of trials. Figure 7-7 below represents a summary of the trials that were evaluated. It should be noted that the summarized results included below were completed in an iterative fashion. As results from various trials were reviewed new trials were developed.

Figure 7-7 Phase II transmission trials

Trial	Pleasant Valley – Sprain-brook HVDC Line	Pleasant Valley – Ruland Road HVDC Line	Sprain-brook-Ruland Road HVDC Line	Marcy – Moses Lines	Oakdale – Fraser Line	Marcy – Princ-etown – New Scotland	Rock Tavern – Ramapo	New Scotland - Leeds	Leeds - Pleasant Valley	115kV Upgrades
Initial	X	X		X	X	X	X	X	X	X
T1		X		X	X	X	X	X	X	X
T2	X			X	X	X	X	X	X	X
T3				X	X	X	X	X	X	X
T4					X	X	X	X	X	X
T5			X	X	X	X	X	X	X	X
T6						X	X	X	X	X
T7							X	X	X	X
T8								X	X	X
T9									X	X
T10					X		X	X	X	X
T12						X		X	X	X
T14						X			X	X
T15						X	X		X	X
T16				X						X

Notes: 1) "X" indicates that the line(s) is included in the Trial.
2) Trial 13 was not included as it is the same as Trial 8, Trail 11 was not included as it only included the 115 kV Projects

7.5 Transmission trial production cost & LBMP results

The metrics analyzed for the full Base Transmission Plan were also calculated for each of the BTP Trials (Figure 7-8). Summaries showing the results for all of the Base Transmission Plan Trials can be seen in the tables below. Detailed results for each of the BTP Trials are found in Attachment 7. In addition, this analysis does not consider any potential ICAP savings which will be discussed and quantified in Section 8 of this report.

Figure 7-8 Transmission trial production cost and LBMP results

BTP Trial	Benefit Annual NYISO Production Cost Savings (M$)	Benefit Annual NYISO Load LBMP Savings (M$)	Cost Annual Project Carrying Charge (M$)	B/C Production Cost	B/C Load LBMP Payment
Initial	199	109	597	0.33	0.18
T1	197	103	456	0.43	0.23
T2	176	82	402	0.44	0.2
T3	175	77	261	0.67	0.3
T4	176	67	213	0.83	0.31
T5	192	103	394	0.49	0.26
T6	144	73	170	0.85	0.43
T7	126	58	108	1.17	0.54
T8	94	57	80	1.18	0.71
T9	75	28	48	1.55	0.58
T10	162	51	151	1.07	0.34
T12	117	67	142	0.83	0.47
T14	87	30	118	0.74	0.25
T15	107	35	146	0.73	0.24
T16	2	23	48	0.04	0.48

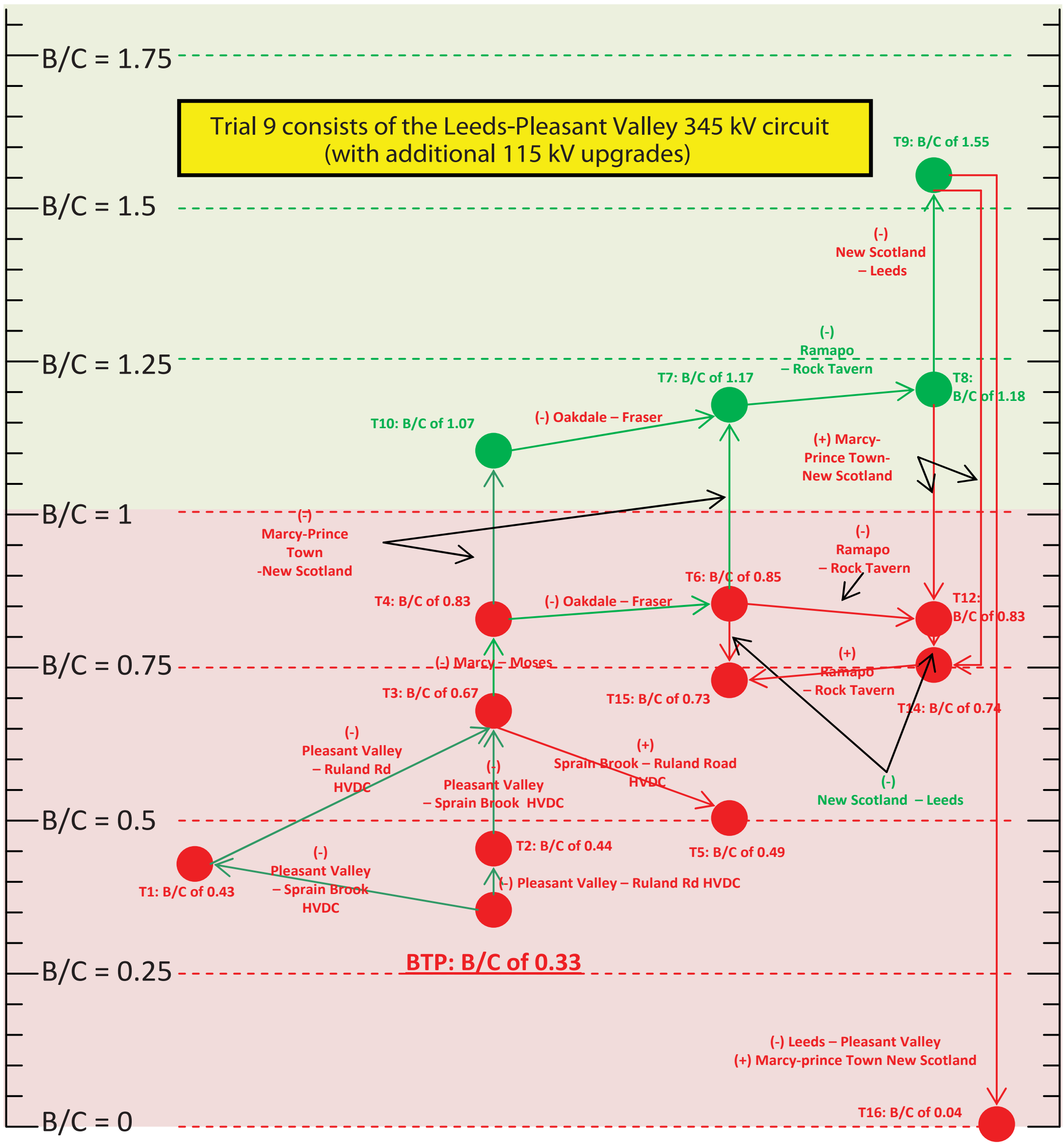
The Production Cost Benefit/Cost Ratio (B/C) results were used as the primary determinant as to whether a Trial is an economic solution. A B/C ratio greater than or equal to 1.0 is typically necessary for a project to be considered economically justified. The Base Transmission Plan provided the greatest benefit of all Trials but also had the highest cost, resulting in a 0.33 B/C ratio based on production costs. As Trials were being developed, specific attention was given to elements that provided incremental benefits, which allowed for the definition of additional Trials. Keeping transmission elements that provided incremental benefit and removing those that were economically detrimental increased the B/C ratios above 1.0 for Trials 7-10. Figures 7-9 and 7-10 show one of the methods used to develop additional Trials as results were being collected and analyzed (complete details can be found in Attachment 8).

Figure 7-9 Incremental benefit analysis

Trial	Benefit (M$)	Cost (M$)	B/C Ratio (M$)	Benefit-Cost (M$)	Inc Benefit (M$)	Inc Cost (M$)	Inc B/C Ratio (M$)
Initial (BTP)	199	597	0.33	-398	-	-	-
T1	197	456	0.43	-259	-	-	-
T2	176	402	0.44	-226	-	-	-
T3	175	261	0.67	-86	-	-	-
Incremental **Marcy-Moses** benefit (T3 to T4):					-1	48	-0.02
T4	176	213	0.83	-37	-	-	-
T5	192	394	0.49	-202	-	-	-
Incremental **Oakdale-Fraser** benefit (T4 to T6):					32	43	0.74
T6	144	170	0.85	-26	-	-	-
Incremental **Marcy/PT/N. Scotland** benefit (T6 to T7):					18	62	0.29
T7	126	108	1.17	18	-	-	-
Incremental **Ramapo-Rock Tavern** benefit (T7 to T8):					32	28	1.15
T8	94	80	1.18	14	-	-	-
Incremental **New Scotland-Leeds** benefit (T8 to T9):					19*	31	0.61
T9	75	48	1.55	27	-	-	-
T10	162	151	1.07	11	-	-	-
T12	117	142	0.83	-25	-	-	-
Incremental **New Scotland-Leeds** benefit (T12 to T14):					30	24	1.26
T14	87	118	0.74	-31	-	-	-
T15	107	146	0.73	-39	-	-	-
T16	2	48	0.04	-46	-	-	-
Incremental **Marcy/PT/N. Scotland** benefit (T4 to T10):					14	62	0.23
Incremental **New Scotland/Leeds** benefit (T6 to T15):					37	24	1.55
Incremental **Ramapo-Rock Tavern** benefit (T6 to T12):					27	28	0.97
Incremental **Marcy/PT/N. Scotland** benefit (T8 to T12):					-23	-62	0.37
Incremental **Marcy/PT/N. Scotland** benefit (T9 to T14):					-12	-70	0.17
Incremental **Oakdale-Fraser** benefit (T10 to T7):					36	43	0.83
Incremental **Ramapo-Rock Tavern** benefit (T14 to T15):					-20	-28	0.72

From the data in Figure 7-8, Trial 9 has the greatest B/C ratio of 1.55. While this provides evidence that Trial 9 is the most beneficial, the remainder of the Trials with a B/C ratio greater than 1.0 could also be justified (Trials 7, 8, and 10).

Figure 7-10 Incremental benefit graphical analysis



Notes:
1) Each trial is depicted as a node with red nodes denoting trials with B/C <1, and green with B/C>1.
2) A red arrow denotes that the B/C ratio decreased implying that more benefit than cost was removed, not a good outcome. A green arrow denotes the reverse, that more cost than benefit was removed, a good outcome.

7.6 Sensitivity analysis assumptions

To evaluate the robustness of the STARS Base Transmission Plan Trials, eight different production cost model sensitivities were developed. Each sensitivity represents a single change applied to both the Replacement Plan and the Base Transmission Plan Case. Decreases in production costs between the two cases indicates the varying economic benefits for the different transmission build-outs provided under alternate future forecasts. Figure 7-11 outlines the eight different sensitivities and the underlying assumptions used to create each of them. A detailed description and results for each of the sensitivities can be found in Attachment 9.

Figure 7-11 STARS sensitivity case assumptions

Sensitivity Case	Assumptions
4,250 MW Wind Generation	Model 4,250 MW Wind Generation from NYISO Queue as Prescribed by NYISO Wind Study
8,000 MW Wind Generation	Model 8,000 MW Wind Generation from NYISO Queue as Prescribed by NYISO Wind Study
Low Fuel Price Forecast	Set Fuel Price to 1 Standard Deviation Lower than Reference Case Forecast (see Attachment 9)
High Fuel Price Forecast	Set Fuel Price to 1 Standard Deviation Higher than Reference Case Forecast (see Attachment 9)
Low Emissions Price Forecast	CARIS I 2009 Values for CO2, SO2, & NOx
High Emissions Price Forecast	$100/Ton CO2 & 2x Reference Case SO2 & NOx Forecast
Shift 1,000 MW Generic Upstate	Remove 1,000 MW of Generic Generation Capacity From Zones J&K and Move to Zone C
Shift 1,000 MW Generic Downstate	Remove 1,000 MW of Generic Generation Capacity From Zone C and Move to Zones J&K

7.7 Sensitivity analysis

Numerous Trials were selected based upon B/C ratios and engineering judgment to evaluate in the sensitivity simulations. The specific trials that were selected for the sensitivity cases included the full BTP, Trial 3, Trial 4, Trial 9, Trial 12 and Trial 14. The changes in the production costs and production cost savings for the trials under each of the sensitivities are summarized in Figures 7-12 through 7-15. A complete set of sensitivity results for each of the Trials evaluated can be found in Attachment 9.

Figure 7-12 Average percent change in NY system production costs by sensitivity

Sensitivity	Average New York System Production Cost Change When Sensitivity is Applied
4250 MW Wind	4%
8000 MW Wind	-6%
Low Fuel Forecast	-9%
High Fuel Forecast	8%
Low Emissions Forecast	-24%
High Emissions Forecast	46%
Shift 1000 MW Upstate	0%
Shift 1000 MW Downstate	-1%

Figure 7-13 Base transmission plan trials sensitivity results by production cost savings percent change

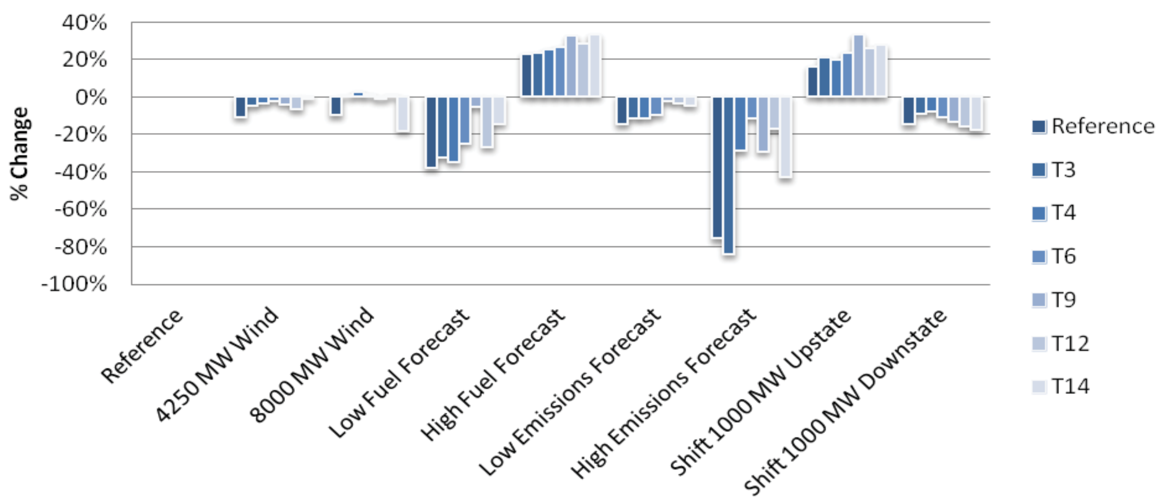
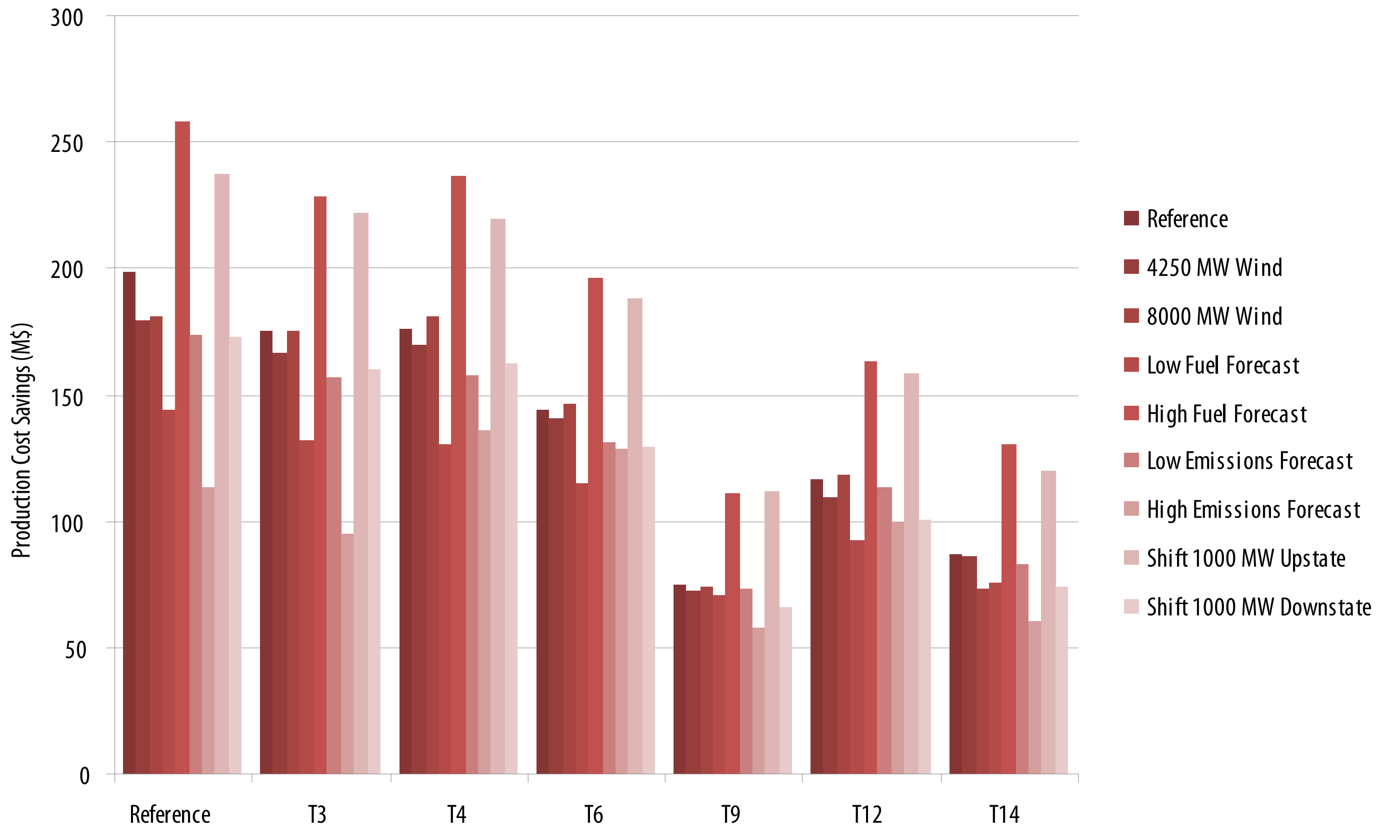


Figure 7-14 Base transmission plan sensitivity results by production cost magnitude



Using Figure 7-15, the general effects of the sensitivities on the STARS BTP Trials can be observed. The generation resource mix upstream and downstream to the transmission projects being evaluated has a significant impact on how each Trial responds to the sensitivities. Figures 7-16 and 7-17 show the upstate (NYISO Zones A-F) and downstate (NYISO Zones G-K) generation resource mix being modeled in the STARS Reference Case:

Figure 7-15 Average percent change in production cost savings by sensitivity

Sensitivity	Average BTP Trial Production Cost Savings Change
4250 MW Wind	-5%
8000 MW Wind	-3%
Low Fuel Forecast	-25%
High Fuel Forecast	27%
Low Emissions Forecast	-8%
High Emissions Forecast	-42%
Shift 1000 MW Upstate	24%
Shift 1000 MW Downstate	-13%

Figure 7-16 NYISO upstate generation resource mix

STARS 2030 NYISO Zones A-F generation capacity by fuel type

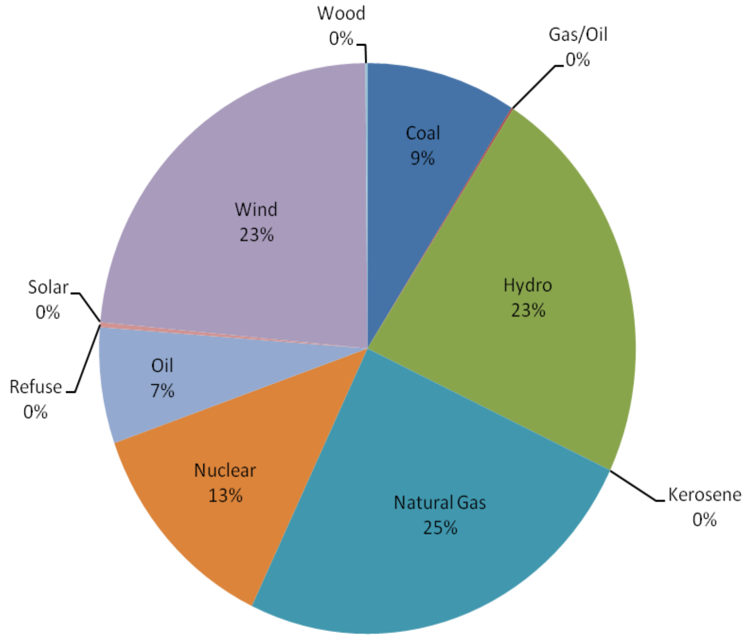
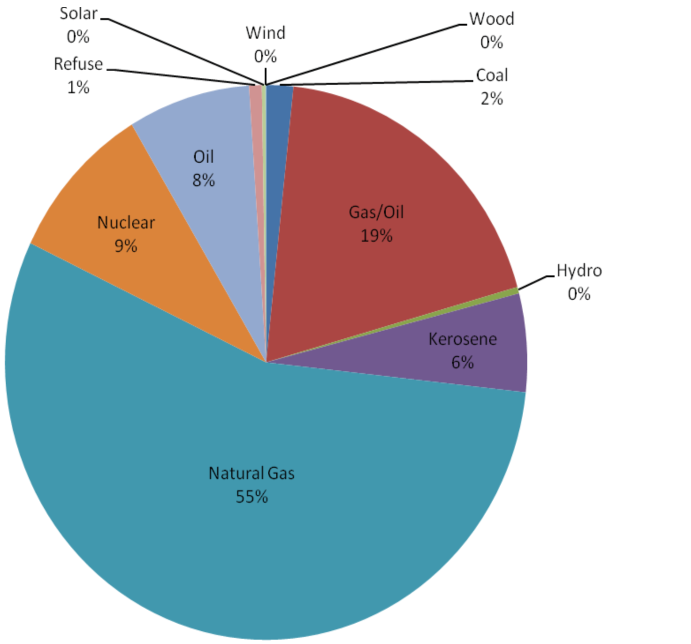


Figure 7-17 NYISO downstate generation resource mix

STARS 2030 NYISO Zones G-K generation capacity by fuel type



Because the upstate area generation is comprised of a large percentage of cheaper renewable and nuclear generation compared to the downstate area which contains mostly fossil fuel based generators, the impacts of fuel and emission price sensitivities will be drastically different between those areas. Reactions of sensitivities involving the addition or relocation of generation are highly dependent upon the exact locations of the generation changes.

When reviewing the results of the sensitivities it is important to note that both hydro and wind generators operate based on a fixed pattern throughout the study year. The energy pattern is based on the geographic location, unit operating limits, and historical data. Fixed output units do have capability to curtail generation if their output causes congestion but curtailed generation was minimal in this study. The fixed units limit the ability of generation in each zone to adjust to changes made to the Base case, including the application of the BTP and the sensitivities. Table 7-18 identifies the wind generation capacity for each NYISO zone for the three different wind generation amounts studied.

Figure 7-18 NYISO nameplate wind generation by zone (MW)

Wind Case	West	Genesee	Central	North	Mohawk Valley	Capital	NYC & LI	Total
4250	917	86	1110	717	1397	0	0	4227
6000	1291	281	1593	1068	1647	70	0	5949
8000	1492	418	1861	1068	1647	70	1400	7955

7.7.1 4,250 MW wind generation sensitivity

This sensitivity represents a decrease in the amount of wind generation capacity from the reference case, which contains 6,000 MW. Figure 7-18 shows the zonal variations in wind generation capacity for each of the wind related sensitivities. The wind generation reductions in this sensitivity occur in zones A-F, which are upstream to transmission bottlenecks. The production cost savings, as a result of reducing the amount of wind generation capacity, is reduced. The benefit of installing transmission in the BTP Trials is diminished as inexpensive generation upstream to the projects and transmission congestion is reduced.

7.7.2 8,000 MW wind generation sensitivity

A majority (70%) of the generation added to the reference case to create the 8,000 MW wind sensitivity was installed in zones J and K based on a proposed New York City / Long Island offshore wind project, with the remainder located in zones A, B, and C. In most BTP Trials there was a negligible change in savings when the sensitivity was applied, with the exception of the Reference Case and Trial T14. When the Reference Case wind generation is increased to 8,000 MW the production cost savings due to the BTP is reduced. With 1,400 MW of new wind generation installed in zones J & K the benefits provided by the BTP are decreased. In Trial 12 there is also a noticeable reduction in savings. The only difference between T12 and T14 is the exclusion of the New Scotland to Pleasant Valley segment of the Marcy-New Scotland-Leeds-Pleasant Valley transmission path. It appears that the removal of this line segment negatively impacts the production cost savings in this sensitivity.

7.7.3 Low fuel price forecast

In the Low Fuel Price Sensitivity prices were set to one standard deviation lower than the base forecast (See Attachment #9). The general effect of reducing fuel prices was to diminish the benefit of each of the BTP Trials that were studied. Lowering fuel prices allows downstate generators to be more competitive against imports from upstate generation and reduces the need for additional transmission capacity to transport energy across the state. Because the fuel forecast sensitivity largely affects oil and natural gas generation, the effect is even more compounding considering the large percentage of these types of generators in downstate zones (see Figures 7-16 and 7-17).

7.7.4 High fuel price forecast

In the High Fuel Price Sensitivity prices were set to one standard deviation higher than the base forecast (See Attachment #9). In contrast to the Low Fuel Price Sensitivity, production cost savings increase when fuel prices are raised. Upstate generation costs increase less than those in the downstate area, due to differing fuel sources as shown in Figures 7-16 and 7-17, therefore indicating that generation is more economic to be transferred from upstate to downstate. The Base Transmission Plan provides more benefit as the price separation between these areas grows, such as in the case of increased fuel prices.

7.7.5 Low emissions price forecast

The low emission price sensitivity reduces the emissions prices by more than 500% for each of the three emissions types. This is a very large decrease in prices and essentially eliminates any emissions adders to generator cost in commitment and dispatch decisions. Without emissions adders, fossil fuel generation in the downstate area is more competitive with upstate generation and produces more energy in this sensitivity as compared to the Reference Case. When the BTP and the BTP trials are added to the low emission Replacement Plan the resulting savings is less than the non-sensitivity case. This is due to the fact that a smaller amount of downstate generation is replaced with upstate generation and less energy transfer is required across the transmission buildout.

7.7.6 High emissions price forecast

The high emissions price sensitivity increases each emissions price forecast by nearly 100%. With emissions cost increases, generation in upstate New York becomes more economic than downstate New York as it is affected less by emissions price changes, with the exception of the coal generators in Western New York. Upstate coal generation provides a portion of the incremental energy beyond hydro, wind, and nuclear to create a production cost savings when the BTP and BTP Trials are installed. With increased CO2 prices, this coal generation incurs much higher costs, and is no longer an economic alternative to downstate generation. Generation in New England increases significantly in this sensitivity, which essentially replaces the Western New York coal generation, increasing the imports cost from New England. For this reason there is a decrease in the production cost savings that the BTP and the BTP Trials provide when emission costs are increased.

7.7.7 Shift 1,000 MW generic generation upstate

In this sensitivity 1,000 MW of generic generation capacity was re-located from NYC and Long Island to the Central zone in upstate New York. As shown in Figure 7-15 there is a material impact on New York production costs when shifting this generation. With more inexpensive generic generation placed on the upstream side of the studied transmission elements the production cost savings provided by the BTP and BTP trials increases by an average of 24%.

7.7.8 Shift 1,000 MW generic generation downstate

In this sensitivity 1,000 MW of generic generation capacity was re-located from the Central zone in upstate New York to NYC and Long Island. As shown in Figure 7-15 there is a minimal impact on New York production costs when shifting this generation. With more inexpensive generic generation placed on the downstream side of the studied transmission elements the production cost savings provided by the BTP and BTP trials are diminished by an average of 13%.

8

Economic analysis -Installed Capacity (ICAP) Savings

Economic analysis-ICAP Savings

8.1 Savings methodology

The calculation of the Installed Capacity Market Savings Metric was performed in accordance to Section 31.3.1.3.5.6 of the NYISO OATT Attachment Y. This requires the approximation of the capacity impact that a transmission project has on the study system through LOLE calculations. The capacity "MW Impact" is then used to determine the monetary benefits associated with a future capacity market, which is an escalated version of the current capacity market, directly from the demand curve. The OATT Attachment Y specifies two calculation "variants" for ICAP savings that represent differing philosophies on the potential benefits that can be obtained in the ICAP market. Both versions of the calculation were performed in the STARS analysis.

8.2 Development of BTP projects and trials

Section 6 of this report described the development of the Base Transmission Plan. Results of economic analysis and transmission utilization warranted evaluation of modifications to the Base Transmission Plan. Some projects in the Base Transmission Plan were removed, modified and/or some projects were added. This resulted in several potential alternatives to the Base Transmission Plan. Section 7 of this report describes the development of these alternatives (trials) and benefit-to-cost ratio calculations associated with each trial. In particular, trials with a B/C ratio greater than 1.0 are justifiable under current NYISO rules for economic projects. Based on these results, the STARS Executive Committee and the STARS TWG recommended further evaluation on the following transmission plans:

- Base Transmission Plan
- Trial 9
- Trial 10

Evaluation of the above plans involved the following analyses. First, a steady-state analysis was performed to evaluate system performance with the proposed plans. The analysis is performed under all-lines in and contingency case conditions to check for potential thermal and/or voltage violations and the results are compared against New York State Reliability Criteria to determine whether the system would be secure with the proposed transmission additions. In addition, emergency transfer limits are established for use in the subsequent LOLE analysis. Next, reliability analysis is performed to determine the impact of the transmission plans on the statewide LOLE. The resulting LOLEs are compared against the Reference Case LOLE (without transmission upgrades). Since the Reference Case LOLE is 0.08 days/year, it can be expected that the LOLEs with the transmission additions will also be ≤ 0.08. Analysis is performed to quantify the excess generation capacity to bring the LOLE back to 0.08. Generation is reduced in all NYCA zones proportionally on the basis of zonal unforced capacity (UCAP) until the base system LOLE of 0.08 is achieved. That amount of reduced generation is the NYCA MW Impact. Finally, the ICAP cost savings are calculated on the basis of the MW Impact.

8.3 Power flow and transfer limit analysis

8.3.1 Case development

The Scenario 3A power flow case for horizon year summer peak conditions was updated with the Hudson Transmission Project (HTP) and the NYISO wind additions (See Section 4.4). Also, the locations of some of the generic units in Zones F, G and J were changed based on the assumptions made in the economic analysis portion of the study as shown in Figure 4-5. The Base Transmission Plan projects were then added to the case. See Attachment 10 for details. The base case generation dispatch inside NYCA was derived from the horizon year BTP Economic Study database prepared by the NYISO (security constrained economic dispatch at the peak load hour). Minor adjustments were made to generation dispatch to mitigate marginal base case and post-contingency violations seen on bulk power system facilities. This case is referred to as the BTP Case.

In addition to the BTP Case, two trial cases were developed:

The Trial 10 Case was developed from the BTP Case by removing the following transmission projects: Pleasant Valley - Sprainbrook HVdc, Pleasant Valley - Ruland Road HVdc, Moses - Marcy 345 kV lines (replaced the existing Moses - Adirondack - Porter 230 kV lines), and Marcy - Princetown - New Scotland 345 kV lines (replaced the existing Porter-Rotterdam 230 kV lines). Trial 10 therefore includes the following BTP facilities only:

- Oakdale-Fraser 345 kV line #2
- New Scotland-Leeds 345 kV #3
- Leeds-Pleasant Valley 345 kV line #3
- Rock Tavern-Ramapo 345 kV line #2
- National Grid 115 kV transmission upgrades

The Trial 9 Case was also developed from the Trial 10 Case by removing the following transmission projects: Oakdale-Fraser #2, New Scotland - Leeds #3, and Rock Tavern - Ramapo #2. Trial 9 therefore includes the following BTP facilities only:

- Leeds-Pleasant Valley 345 kV line #3
- National Grid 115 kV transmission upgrades

8.3.2 Power flow analysis

Power flow analysis was performed on the above-mentioned cases using the same methodology as in the earlier Phase I and Phase II work. For the purposes of this analysis, transmission facilities rated 100 kV and above within NYCA (and tie-lines out of NYCA) were monitored. For thermal overloads, each branch element (transformer, transmission line, or feeder in the monitored system) was monitored and electrical flows above the applicable branch rating (normal continuous rating - Rate A) under system intact conditions, LTE rating (Rate B) under contingency conditions for overhead transmission lines and STE rating (Rate C) for underground feeders were flagged. Bus voltages were monitored for range violations and voltage collapse. Phase angle regulators (PARs), switched shunts and LTC transformers are modeled as regulating pre-contingency and non-regulating post-contingency.

The following types of contingencies were simulated based on the contingency files provided by NYISO and NYTOs:

1. Outage of branches connected between buses with a base voltage of 100 kV and above (these included outages based on "automatic" N-1 contingency specification in MUST and specific pre-defined branch outages)

2. Generation contingencies
3. Series element contingencies
4. Bus contingencies
5. HVDC contingencies

In addition to these contingencies, other contingencies provided by National Grid associated with wind generation in the North Country were simulated. No stuck-breaker or tower contingencies were simulated.

Results of the power flow analysis on the above-mentioned cases showed some thermal overloads and voltage violations. These violations were reviewed by the STARS TWG. Several of the violations were dismissed as local area issues that have nothing to do with contingencies on the NYS Bulk Power System. Mitigation for these violations will be established through the local area planning process performed by the NYTOs. In addition, local area generation adjustments and/or SPS action can be used to mitigate other violations seen in this study.

8.3.3 Transfer limit analysis

After completing the power flow analysis, emergency transfer limits were calculated for key interfaces in the NYCA system. See Attachments 10 through 12. Figure 8-1 compares the calculated thermal transfer limits between the three cases. Figures 8-2 through 8-5 show the limiting facilities associated with the emergency transfer limits in each of the cases.

Figure 8-1 Comparison of emergency thermal transfer limits for horizon year between BTP, Trial 10 and Trial 9 cases

Interface	Intermediate Yr. Summer Peak Case Without BTP	Limiting Facility Table 8-2	Horizon Year Summer Peak Case With BTP	Limiting Facility Table 8-3	Horizon year Summer Peak Case Trial 9	Limiting Facility Table 8-4	Horizon year Summer Peak Case Trial 10	Limiting Facility Table 8-5	T9-BTP MW	T9-BTP %	T10-BTP MW	T10-BTP %
Dysinger East	3225	1	2950	1	2975	1	2975	1	25	1%	25	1%
West Central	1825	1	1775	1	1800	1	1825	1	25	1%	50	3%
Volney East	4550	2	4300	2	4100	2	3875	2	-200	-5%	-425	-10%
Moses South	2650	7	4200	3	2325	3	2325	3	-1875	-45%	-1875	-45%
Total East (Closed)	6700	2	7750	2	7575	4	7550	2	-175	-2%	-200	-3%
Central East (Note 1)	3000	3	4175	4	2975	4	3550	4	-1200	-29%	-625	-15%
Central East + Fraser-Gilboa (Note 1)	3200	2	3725	2	3350	4	3325	2	-375	-10%	-400	-11%
CE Group (Note 1)	5175	2	5650	2	5275	4	5250	2	-375	-7%	-400	-7%
F to G	3475	4	5250	5	4525	4	5425	5	-725	-14%	175	3%
UPNY-SENY Open (Note 2)	5225	4	7275	2	6950	4	6950	2	-325	-4%	-325	-4%
UPNY-ConEd Open	5800	5	7525	6	6825	5	7400	6	-700	-9%	-125	-2%
Millwood South Closed (Note 3)	9775	8	11275	6	10850	5	11250	6	-425	-4%	-25	0%
I to J	4450	6	4475	7	4450	6	4475	7	-25	-1%	0	0%
Dunwoodie South Open	5725	6	5700	7	5675	6	5675	7	-25	0%	-25	0%
I to K	1275	9	1275	8	1275	7	1275	8	0	0%	0	0%
LIPA Import	2875	9	3475	8	2900	7	2900	8	-575	-17%	-575	-17%

Notes:

1. Excludes Plattsburgh-Sandbar 115 kV line
2. Excludes Jefferson-Ramapo 500 kV line
3. Horizon year definition of this interface includes the Hudson Transmission Project (HTP)
4. Interface limits rounded down to the nearest 25 MW to be consistent with NYISO practices

Figure 8-2 *Limiting facilities for emergency thermal transfer limit calculations (Intermediate year case without BTP projects)*

Limiting Facility		Limiting Rating MVA	Contingency
1	Stolle-Meyer 230	430	Pre-disturbance
2	Coopers Corners-Frasers 345	1207	Pre-disturbance
3	New Scotland77-Leeds 345	1724	L/O New Scotland99-Leeds 345
4	Pleasant Valley-Leeds 345	1725	L/o Athens-Pleasant Valley 345
5	Middletown Tap-Coopers Corners 345	1793	L/O Rock Tavern-Coopers Corners 345
6	Dunwoodie-Mott Haven 345	783	Pre-disturbance
7	Moses-Adirondack 230	440	L/O Massena-Marcy & Massena-Chateaguay
8	Roseton-Fishkill 345	1935	Pre-disturbance
9	Dunwoodie-Shore Rd 345	653	Pre-disturbance

Notes:
1. Excludes Plattsburgh-Sandbar 115 kV line
2. Excludes Jefferson-Ramapo 500 kV line
3. The limiting transfer for the I-to-K and LIPA Import interfaces is Y50 (Dunwoodie – Shore Road 345 kV). The limit is based on the MW rating for Y50 (653 MW)

Figure 8-3 *Limiting facilities for emergency thermal transfer limit calculations (Horizon Year case with BTP projects)*

Limiting Facility		Limiting Rating MVA	Contingency
1	Wethersfield - Meyer 230	430	Pre-disturbance
2	Fraser - Coopers Corners	1207	Pre-disturbance
3	Marcy 765/345 T2	2338	L/O Marcy 765/345 T1
4	New Scotland 77 - Leeds 345	1724	L/O New Scotland - Leeds #3
5	Leeds - Pleasant Valley #1 (existing)	1724	L/O Leeds - Pleasant Valley #3
6	Roseton-Fishkill 345	1935	Pre-disturbance
7	Dunwoodie-Mott Haven 71	783	Pre-disturbance
8	Dunwoodie-Shore Rd 345	653	Pre-disturbance

Notes:
1. Excludes Plattsburgh-Sandbar 115 kV line.
2. Excludes Jefferson-Ramapo 500 kV line.
3. Horizon year definition includes PV - Sprainbrook HVdc (900 MW) and PV - Ruland Road HVdc (600 MW)
4. Horizon year definition includes PV - Sprainbrook HVdc (900 MW) and PV - Ruland Road HVdc (600 MW) and the Hudson Transmission Project (HTP)
5. Horizon year definition includes PV - Ruland Road HVdc (600 MW)
6. The limiting transfer for the I-to-K and LIPA Import interfaces is Y50 (Dunwoodie – Shore Road 345 kV). The limit is based on the MW rating for Y50 (653 MW)

Figure 8-4 Limiting facilities for emergency thermal transfer limit calculations (Horizon Year case with Trial 9 projects)

Limiting Facility		Limiting Rating MVA	Contingency
1	Niagara-Rochester 345	1685	L/O Kintigh-Rochester 345
2	Fraser - Coopers Corners 345	1207	Pre-disturbance
3	Marcy 765/345 AT1	1756	L/O Marcy 765/345 AT2
4	New Scotland 77 - Leeds 345	1724	L/O New Scotland 99 - Leeds 345
5	Roseton-Fishkill 345	1935	Pre-disturbance
6	Dunwoodie-Mott Haven 71	783	Pre-disturbance
7	Dunwoodie-Shore Rd 345	653	Pre-disturbance

Notes:

1. Excludes Plattsburgh-Sandbar 115 kV line.
2. Excludes Jefferson-Ramapo 500 kV line.
3. Includes Hudson Transmission Project (HTP).

Figure 8-5 Limiting facilities for emergency thermal transfer limit calculations (Horizon Year case with Trial 10 projects)

Limiting Facility		Limiting Rating MVA	Contingency
1	Niagara-Rochester 345	1685	L/O Kintigh-Rochester 345
2	Fraser - Coopers Corners 345	1207	Pre-disturbance
3	Marcy 765/345 AT1	1756	L/O Marcy 765/345 AT2
4	Marcy - New Scotland 345	1792	L/O Edic - New Scotland 345
5	Leeds - Pleasant Valley #1 (existing)	1725	L/O Leeds - Pleasant Valley #3
6	Roseton-Fishkill 345	1935	Pre-disturbance
7	Dunwoodie-Mott Haven 71	783	Pre-disturbance
8	Dunwoodie-Shore Rd 345	653	Pre-disturbance

Notes:

1. Excludes Plattsburgh-Sandbar 115 kV line.
2. Excludes Jefferson-Ramapo 500 kV line.
3. Includes Hudson Transmission Project (HTP).

In addition to these limits, emergency voltage transfer limits were calculated for the Central East, Central East + Fraser-Gilboa and Central East Group interfaces. These interfaces have traditionally been voltage limited, whereas the other interfaces have tended to be thermally limited. So for purposes of this study, voltage transfer limits were only calculated for the Central East related interfaces. Figure 8-6 compares the voltage limits between the three cases.

Figure 8-6 Comparison of voltage transfer limits for Central East interfaces, BTP case vs. Trial 10 Case vs. Trial 9 Case

	Horizon year limit with BTP		Horizon year limit with BTP Trial 10				Horizon year limit with BTP Trial 9			
	Voltage transfer limit	Limiting facility	Voltage transfer limit	Limiting facility	T10-BTP		Voltage transfer limit	Limiting facility	T9-BTP	
					MW	%			MW	%
CENTRAL EAST	3275	3	2800	1 & 2	-475	-14.5	2775	1 & 2	-500	-15.3
CE + FRASER-GILBOA	3700	3	3225	1 & 2	-475	-12.8	3150	1 &2	-550	-14.9
CE-GROUP	5550	3	5000	1 & 2	-550	-9.9	4875	1 & 2	-675	-12.2

Additional details on the transfer limit calculations and comparison against previously derived limits are given in Attachments 10 through 12. The more limiting of the two transfer limits (thermal vs. voltage) is used in the LOLE calculations. This is described in the next section.

8.4 Reliability analysis

The Scenario 3A GridView model used in the initial Phase II analysis was updated with the HTP project and NY-ISO wind additions as described in Section 4.4 of this report. Three separate models were then developed by adding the BTP, Trial 10 and Trial 9 projects. The models were updated with the corresponding emergency transfer limits derived in Section 8.3.3. Voltage transfer limits were used for the Central East interfaces as these are more limiting than the corresponding thermal limits.

Results of the reliability analysis on the BTP Case show that the statewide LOLE is 0.070 days/year. As expected, it is below the statewide LOLE of 0.080 days/year from the Reference Case. The corresponding LOLE in the Trial 9 and 10 Cases is 0.074 days/year.

Figure 8-7 compares the zonal and statewide LOLEs between the BTP Case, Trial 10 and Trial 9 Cases.

Figure 8-7 Comparison of zonal and statewide LOLEs between BTP, Trial 10 and Trial 9 cases

	Horizon year's LOLE (days/year)		
Zones	BTP case	Trial 10 case	Trial 9 case
A	-	-	
B	0.017	0.021	0.018
C	-	-	
D	-	-	
E	0.044	0.040	0.045
F	-	-	0.002
G	0.068	0.071	0.063
H	-	-	
I	0.064	0.063	0.070
J	0.061	0.074	0.074
K	0.066	0.073	0.075
NYCA	0.070	0.074	0.074

8.5 ICAP MW impact analysis

ICAP MW Impact analysis was performed on the BTP and Trial 9 Cases to quantify the impact of the added transmission. Since the Trial 9 and Trial 10 cases showed the same LOLE (0.074 days/year), it can be assumed that both Trials will have similar MW Impacts – therefore the analysis that was performed on the Trial 9 case should apply to the Trial 10 case.

8.5.1 BTP case

In order to determine the MW capacity impact of the BTP projects, new generation capacity was reduced and LOLE recalculated. Zonal generation unforced capacity (UCAP) was used as a basis for the generation reductions. In other words, new generation capacity in each zone was reduced in proportion to the unforced generation capacity (UCAP). Because LOLE varies in a non-linear fashion with the generation capacity (or load), this LOLE calculation is an iterative process involving reduction of generation capacity until the NYCA's LOLE of 0.08 days/year (as in original Replacement Plan case) is reached. Then, the amount of capacity that was backed off is the "MW Excess".

After several iterations, with 400 MW new generation capacity reduction, the NYCA LOLE reaches 0.08 days/yr. See Figure 8-8. The new generation capacity reductions are shown in Figure 8-9. So the MW Impact of the BTP projects is 400 MW(See Attachment 13).

Figure 8-8 Calculated LOLE for BTP cases with and without generation reduction based on zonal UCAP proportion

	Horizon year's LOLE (days/year)	
Zones	Base Transmission Plan case	BTP case with reduced new generation
A	-	-
B	0.02	0.02
C	-	-
D	-	-
E	0.04	0.05
F	0.00	0.00
G	0.07	0.07
H	-	-
I	0.06	0.07
J	0.06	0.07
K	0.07	0.08
NYCA	0.07	0.08

Figure 8-9 New generation capacity in BTP case based on zonal UCAP proportion (from NYISO)

Zones	UCAP using 2011 translation factors (MW)	MW reduction
A	4,743	48
B	866	9
C	6,421	65
D	1,679	-
E	972	27
F	3,679	37
G	2,813	28
H	2,227	-
I	93	23
J	9,758	98
K	6,425	65
Total	39,676	400

8.5.2 Trial 9 case

In order to determine the MW capacity impact of the projects in both trials, new generation capacity was reduced and LOLE recalculated. Zonal generation unforced capacity (UCAP) was used as a basis for the generation reductions. In other words, new generation capacity in each zone was reduced in proportion to the unforced generation capacity (UCAP). Because LOLE varies in a non-linear fashion with the generation capacity (or load), this LOLE calculation is an iterative process involving reduction of generation capacity until the NYCA's LOLE of 0.08 days/year (as in the Scenario 3A case) is reached. Then, the amount of capacity that was backed off is the "MW Impact". This MW Impact would be identical for both Trials 9 and 10 based on the reported LOLE findings in Section 8.4.

Figure 8-10 Calculated LOLE for T9 case with and without generation reduction, based on zonal UCAP proportion

	Horizon year's LOLE (days/year)	
Zones	T9 case	T9 case with reduced new generation
A	-	-
B	0.02	0.02
C	-	-
D	-	-
E	0.04	0.05
F	0.00	0.00
G	0.06	0.08
H	-	-
I	0.07	0.08
J	0.07	0.08
K	0.08	0.08
NYCA	0.07	0.08

Figure 8-11 New generation capacity in Trial 9 case, based on zonal UCAP proportion

Zones	UCAP using 2011 translation factors (MW)	MW reduction
A	4,743	32
B	866	6
C	6,421	44
D	1,679	0
E	972	18
F	3,679	25
G	2,813	19
H	2,227	0
I	93	16
J	9,758	66
K	6,425	44
Total	39,676	270

After several iterations, with 270 MW new generation capacity reduction, the NYCA LOLE reaches 0.08 days/yr. See Figure 8-10. The new generation capacity reductions are shown in Figure 8-11. So the MW capacity impact of the projects is 270 MW(See Attachment 13).

8.6 Installed capacity savings of MW impact

The results for the annual ICAP savings calculation variants for the three trials studied are presented in figures 8-12 and 8-13. Three levels of demand curve escalation are included as sensitivities to the growth rate of the ICAP market prices.

Figure 8-12 Variant No. 1 installed capacity savings

ICAP Demand Curve Escalation Sensitivity	BTP Savings (M$)	Trial 9 & 10 Savings (M$)
1%	56	38
3%	82	55
5%	117	79

Figure 8-13 Variant No. 2 installed capacity savings

ICAP Demand Curve Escalation Sensitivity	BTP Savings (M$)	Trial 9 & 10 Savings (M$)
1%	150	101
3%	218	147
5%	314	212

A detailed description of how the ICAP savings calculations are performed can be found in the NYISO CARIS Phase I 2011 Appendix E.1.2.6. Additional results, including the projected demand curve prices and savings by ICAP locality can be seen in Attachment 14.

9
Conclusions

Conclusions

This study has been performed over three years. It is recognized that over time, conditions change. Accordingly, the STARS TWG has made every effort to update assumptions as practical.

As with any study of this nature, periodic updates will be required. Despite changing conditions, the findings and recommendations provided in this study are sufficiently robust and supported by the analytical work included in the report and its attachments. The following are identified as key findings of this study which provide guidance into strategic long range investment needs into the State's transmission system. These investments will ensure that aging infrastructure is replaced and in some cases upgraded in a prudent and coordinated manner to maintain and in some cases enhance system reliability. It also supports the fact that there are projects that can deliver economic benefits by reducing congestion as well as projects that can help to achieve the State's public policy goals of enabling the integration of greater amounts of renewables.

KEY FINDINGS THAT PROVIDE GUIDANCE INTO LONG-RANGE INVESTMENT NEEDS

1. **40% of the existing transmission system will likely need to be replaced over the next 30 years:** The state's transmission infrastructure is well maintained, but aging. A high-level aged based condition assessment by the STARS TWG of this infrastructure has identified the potential need to replace, over the next 30 years, nearly 4,700 miles of transmission lines at operating voltages of 115 kV and greater. The estimated cost of this replacement is more than $25 billion.
2. **Study assumptions including generation location, type and fuel price forecasts significantly impact findings:** The longer time horizon of the study introduces uncertainty related to key assumptions including forecasted load levels, new generation resources including locations, size and type, as well as similar issues regarding the degree of penetration of and locations of demand side resources. The actual future mix of generation types, fuel costs, emission regulation and allowance prices, as well as the location of new generation additions can have a significant impact on the results of the study.
3. **Reliability needs are met under the statewide generation expansion scenario:** Based on the selected statewide generation expansion scenario, which assumed that generation was added proportional to load growth, the system meets existing reliability criteria. This scenario did not include significant expansion of the capability of imports from external control areas, such as Hydro-Quebec. This statewide generation expansion scenario represents a conservative view of potential transmission needs. Analysis of other generation expansion scenarios where more generation is sited upstate or where imports are relied on more heavily, show that the system does not meet established reliability criteria, increasing the need for more transmission.
4. **New transmission will unbottle wind resources:** The NYISO has identified as part of their 2010 Wind Generation Study that as part of the integration of 6,000 MW of wind resources nearly 9% of the wind energy production in three upstate areas would be "bottled" or be undeliverable to the transmission system. The study identifies and models the impacts of the underlying local transmission system upgrades that will allow for the nearly full unbottling of these resources. These upgrades allow for the full utilization of these resources which have been constructed under the State's Renewables Portfolio Standard. The STARS study assumed that these upgrades were in place. The approximate cost of these upgrades ranges from $75 million to $325 million, depending upon the scope of the upgrades constructed. No assumptions in the

STARS study were made on how these projects would be developed, but they represent additional transmission investment opportunities.

5. **New transmission projects with economic benefits:** The study has identified several projects that provide economic benefits by increasing transfer limits on existing constraints within the state's grid. Projects such as the 3rd Leeds to Pleasant Valley line, a 3rd New Scotland to Leeds line and 2nd Rock Tavern to Ramapo line show promise. These lines would be located within or with minor expansions of existing rights of way. The estimated costs of these projects are slightly over $400M. These projects shows annual net benefits based on production cost savings of $18M per year.
6. **Cost effective incremental transmission upgrades:** Based on the overlay of the condition assessment work and the STARS trials there are upgrade projects that provide increased transmission capability at a relatively modest cost. Projects such as the upgrade from 230 kV to 345 kV of the Moses to Marcy, Marcy to Rotterdam section of the Marcy to New Scotland line and the Oakdale to Fraser line are good examples. Again these lines would be located within or along existing transmission corridors. The replacement costs of these lines is approximately $1.0B, with the estimated additional upgrade costs of these projects slightly over $600M.
7. **Ancillary benefits of a more robust system:** The system transmission upgrades studied in STARS improve the robustness of the transmission system, which in turn have the potential to reduce the levels of generation reserves required to maintain system reliability.
8. **Upgrades to Moses South are further justified with increased Hydro Quebec imports:** The NYCA import limit from the Quebec Chateauguay-Massena single 765 kV interconnection was modeled at 1,380 MW per current NYISO operating criteria, which prevents a single external NYCA source from exceeding the largest internal contingency, in this case Nine Mile Point Station #2 at a projected capacity of 1380 MW. The thermal capability of the Chateauguay substation, with four 765/120 kV transformers placed in service, is approximately 2370 MW. The operating limitation on the Chateauguay-Massena 765 kV line as a single source limited the benefit that can be realized by the Moses South 230 kV to 345 kV upgrades in the STARS Base Transmission Plan.
9. **HVDC lines may help meet public policy objectives:** The HVDC lines from Pleasant Valley to NYC and Long Island that were analyzed as part of the study do not appear to be justified based on either reliability or economic benefits, but may be justified based on Public Policy goals.

Building off the findings described in detail above the STARS TWG makes the following recommendations as to the long-term action plans that would best address the maintenance and selected upgrades of the State's electric transmission infrastructure. These recommendations can help to achieve the goals of continued safe and reliable service of this infrastructure which is critical to the economic viability of the state. In addition known historical congestion points on the system can be addressed in a responsible manner and projects which will able full deliverability of the State's renewable resources can be achieved.

1. Each Transmission Owner should continue to assess the condition of their assets to provide for the long-term reliability of the state's transmission infrastructure as part of their normal capital planning process.
2. Coordinated transmission studies (such as STARS) should be performed and updated on a periodic basis as they provide a mechanism to develop optimized, long-term

investment strategies for the state's transmission infrastructure.

3. There are several projects that reduce congestion and provide economic benefits through lower production costs; these projects should be pursued. These 345 kV projects include the 3rd Leeds-Pleasant Valley line, 3rd New Scotland-Leeds line and 2nd Rock Tavern-Ramapo line. Construction of these lines leverages, to the extent possible, the use of existing rights-of-way.
4. To meet state public policy objectives of increased renewable resources, the underlying local upgrades identified in the NYISO 2010 Wind Generation Study should be constructed based on a review of the status of the development of the wind projects in the three upstate areas identified in that study. This would lead to greatly improved deliverability of wind resources and reduced emissions.
5. The export limit from Hydro-Quebec's Chateauguay station to New York is approved at 2,370 MW with all equipment in service, which includes four 765/120 kV transformers. The NYCA import limit from the Quebec Chateauguay-Massena single 765 kV interconnection is, however, limited to 1,380 MW per current NYISO operating criteria, which prevents a single external NYCA source from exceeding the largest internal contingency, in this case Nine Mile Point Station #2 at a projected capacity of 1,380 MW. If there is a desire, from a public policy perspective, to increase the import capability of hydro generation from Quebec, additional analysis would be needed to determine how to best address the loss of single source contingency.
6. Specific projects were identified (3rd Leeds to Pleasant Valley line and 2nd Rock Tavern to Ramapo line) that can be a significant part of solving the reliability needs that would be created with the potential retirement of the Indian Point Energy Center. Several other projects such as the Marcy South Series Compensation and Staten Island Generation Unbottling projects were not evaluated as part of the study, but should be further considered since they appear to provide additional value.
7. Several transmission lines that are approaching the end of their useful life should be considered for upgrading to improve the strength of the transmission system backbone. These projects include the upgrade to 345 kV of the Moses to Marcy, Marcy to Rotterdam section of Marcy to New Scotland line and the Oakdale to Fraser line. Upgrades of these lines leverages the use of existing rights-of-ways.

While the STARS study was initially envisioned to include three phases, with the emergence of the Governor's State Energy Highway Task Force, the Phase III work will not be performed at this time. It is felt that the analyses work performed by STARS could be a key input into the work of the Task Force and could help to provide a road-map for the development of projects to meet the Governor's objective of establishing a State Energy Highway.

10

References

References

[1] New York State Transmission Assessment and Reliability Study (STARS) Phase 1 Study Report – "As Is" Transmission System. Report issued by ABB, January 13, 2010.
[2] Growing Wind – Final Report of the NYISO 2010 Wind Integration Study, September 2010.

Exhibit No. NYT-6

NEW YORK INDEPENDENT SYSTEM OPERATOR

10 Krey Boulevard ♦ Rensselaer, NY 12144

December 9, 2013

Re: ***NYISO 2013 Congestion Assessment and Resource Integration Studies Report***

Dear NYISO Economic Planning Interested Parties:

On November 19, 2013 the New York Independent System Operator, Inc. (NYISO) Board of Directors approved the attached 2013 Congestion Assessment and Resource Integration Studies Report (2013 CARIS Report). The 2013 CARIS Report was developed in compliance with the NYISO's Tariff, specifically Attachment Y of the NYISO's Open Access Transmission Tariff (OATT). Market participants actively engaged in the development of the 2013 CARIS model assumptions, the review of analysis results, and the review and approval of the final 2013 CARIS Report.

The 2013 CARIS Report presents the impact of historic and projected congestion on the New York Control Area electric system and the potential benefits to New York consumers of generic generation, transmission, demand response, and energy efficiency solutions. The impact of historic and projected congestion is determined in accordance with the applicable provisions of the NYISO's OATT, as are the potential benefits of the generic solutions. The NYISO's OATT requires that New York system-wide production cost savings be the sole metric for the evaluation of the economic benefit of projects in the CARIS process. Under this tariff-prescribed process, a project's projected benefits are, in turn, compared to the cost of that project to produce a benefit-cost ratio. The time-horizon over which project benefits are measured is limited to ten years.

Analysis of additional metrics such as capacity market savings and environmental benefits are included in the 2013 CARIS Report, for informational purposes only. Consistent with the method prescribed by the NYISO's OATT, metrics other than production cost savings and the informational metrics are not evaluated in the 2013 CARIS. Such other metrics may include impacts to system reliability, grid operations, economic development, property taxes and employment. As a result, the benefit-cost ratios presented in the 2013 CARIS Report reflect some, but not necessarily all of the benefits associated with transmission upgrades or other potential solutions to address system congestion.

The 2013 CARIS Report provides one tool for stakeholders to make an economic assessment of transmission congestion relief solutions. However, the benefits of proposed upgrades may be evaluated by examining additional metrics beyond only production cost savings. Accordingly, the benefit-cost ratio of a particular project may be materially different based on the specific metrics evaluated.

Respectfully submitted,

/s/ Henry Chao
Henry Chao
Vice President, System Resource Planning

2013 Congestion Assessment and Resource Integration Study

Comprehensive System Planning Process

CARIS – Phase 1

November 19, 2013

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.

Caution and Disclaimer

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Executive Summary

1. Overview

With the publication of this *2013 Congestion Assessment and Resource Integration Study (CARIS) Phase 1 Report,* the New York Independent System Operator (NYISO) has completed the first phase 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 (2008-2012) and projected (2013-2022) 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 projects as solutions.

The report also discusses key assumptions adopted for this analysis, and changes to key assumption from the prior CARIS Phase 1 analysis, some of which resulted in reduced congestion projections for the next 10 years, for example, the extended operation of the Athens Special Protection System (SPS)[2] and the timing of new in-city generators becoming operational. The Athens SPS operating contract was recently extended until a permanent solution is developed within the next 10 years. The operation of the SPS allows the use of higher thermal ratings for the Leeds to Pleasant Valley transmission lines under certain dispatch conditions, which reduces the congestion that would otherwise be resolved by permanent transmission reinforcement. An overview of the major assumption changes appears later in this Executive Summary with additional details provided in Section 4.1 of the main report.

Generic solutions -- transmission, generation, demand response (DR) and energy efficiency (EE) -- were applied to relieve congestion for the three most congested elements or group of elements in the New York Control Area (NYCA) without assessing the feasibility of such projects. The primary metric to measure benefits to be used in the benefit-cost analysis in accordance with the Tariff is the NYCA-wide production cost savings. In order to provide more information, additional benefit metrics such as emissions costs, load and generator payments, Installed Capacity (ICAP) savings, and Transmission Congestion Contract (TCC) payments are also presented. While some versions of these metrics indicated significant additional benefits, it is important to note that they were not included among the benefits used in calculating the benefit to cost (B/C) ratio which is in accordance with the Attachment Y to the NYISO's Open Access Transmission Tariff (Tariff) requirements. The costs of the generic

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

[2] The Athens SPS was originally put in operation in 2008 as a temporary solution to address the energy deliverability of the Athens unit. The recently extended agreement between National Grid and Athens will maintain the Athens SPS in place until 2023, or until the construction of a permanent physical reinforcement. For further information see FERC Docket No. ER13-822-000.

solutions were based upon estimates of low, mid and high solution costs. The B/C ratios for the generic solutions are shown in Figure 1.

As reflected in the variance in B/C ratios across the three studies and across solutions within the studies, there is a significant range in production cost savings and solution costs. All of the high and mid range cost estimates produced B/C ratios that are less than one and thus reflect the fact that their projected costs outweighed their estimated production cost savings over the Study Period. Only one of the low range cost estimates produced a B/C ratio greater than one. The energy efficiency solution for the Central East constraint produced a B/C ratio greater than one primarily because of its substantial impact on production cost savings relative to the other generic solutions analyzed. In contrast to the 2011 CARIS, the low-cost transmission no longer appears to be an economic solution because of an overall reduction in production cost savings projected in this study.

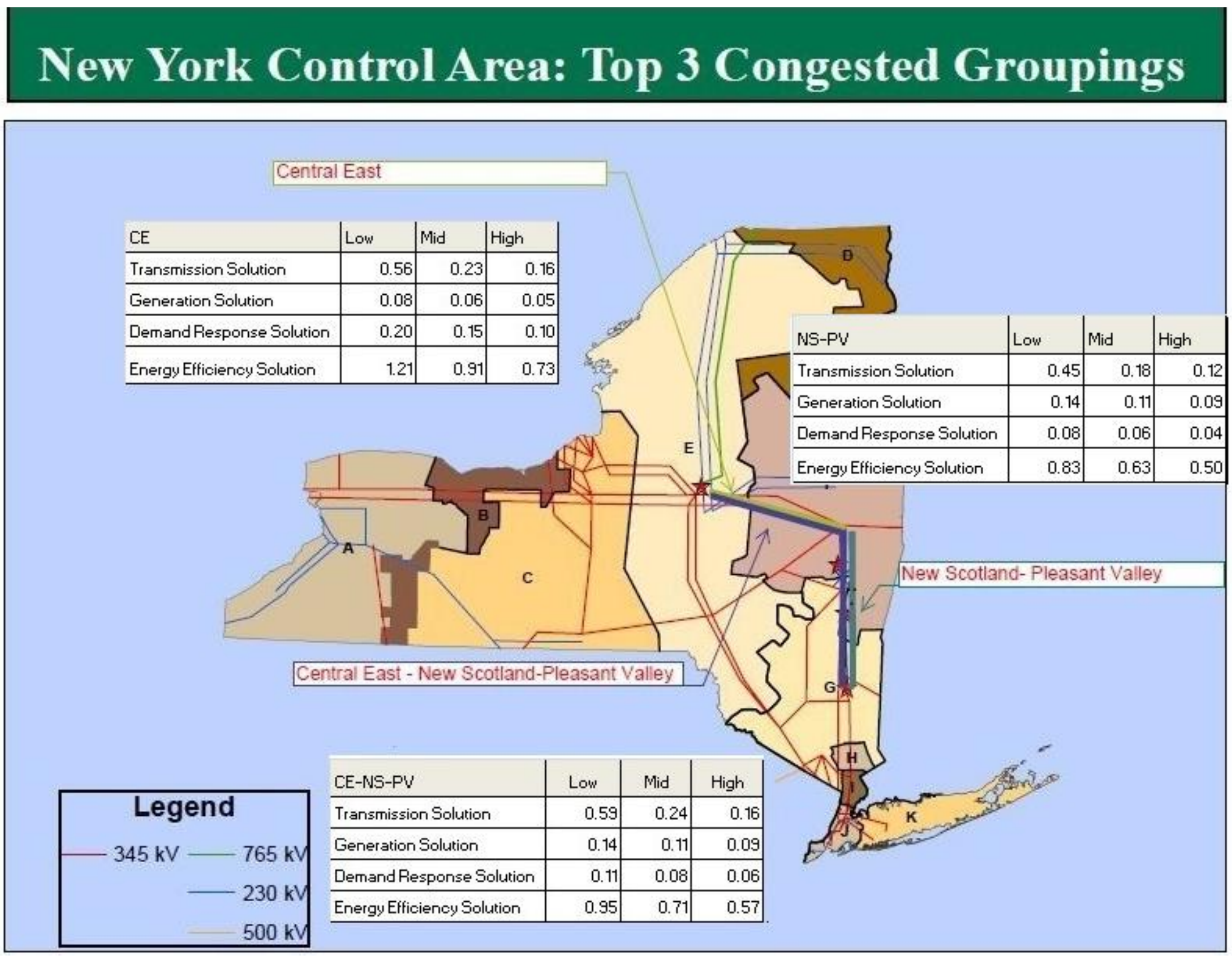


Figure 1: Generic Solutions Benefit/Cost Ratios

2. Summary of Study Process and Results

A. The Three Congestion Studies

Consistent with the CARIS procedures, the NYISO ranked and grouped transmission elements with the largest production cost savings when congestion on that constraint was relieved. The groupings selected for the three 2013 CARIS studies are shown in Figure 2 along with the present value of projected congestion. Specifically, the studies are: Central East - New Scotland - Pleasant Valley (Study 1;CE-NS-PV), Central East (Study 2;CE), and New Scotland - Pleasant Valley (Study 3;NS-PV) and the annual congestion is shown in Figure 3.

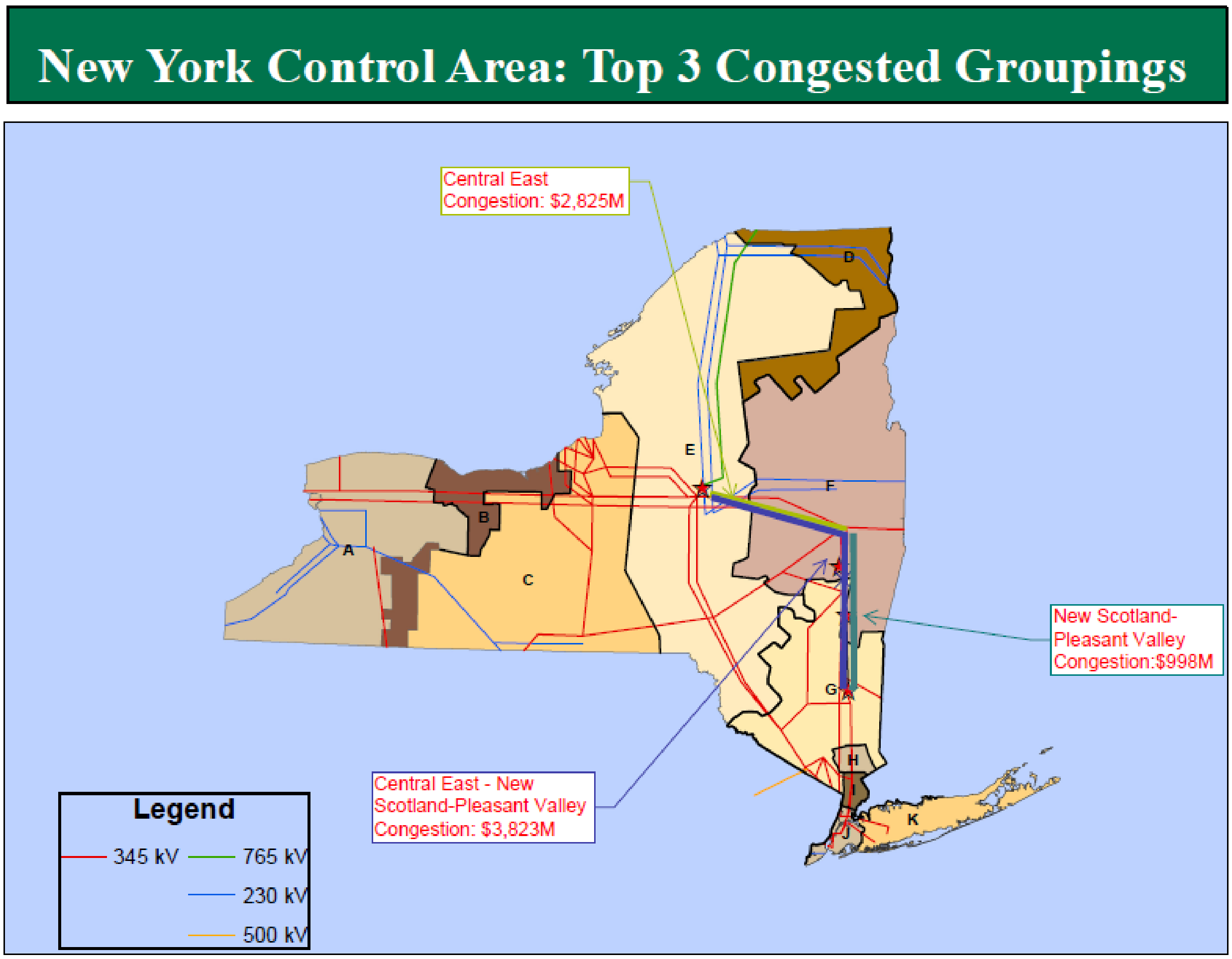


Figure 2: Congestion on the Top Three CARIS Groupings (Present Value in 2013 $M)

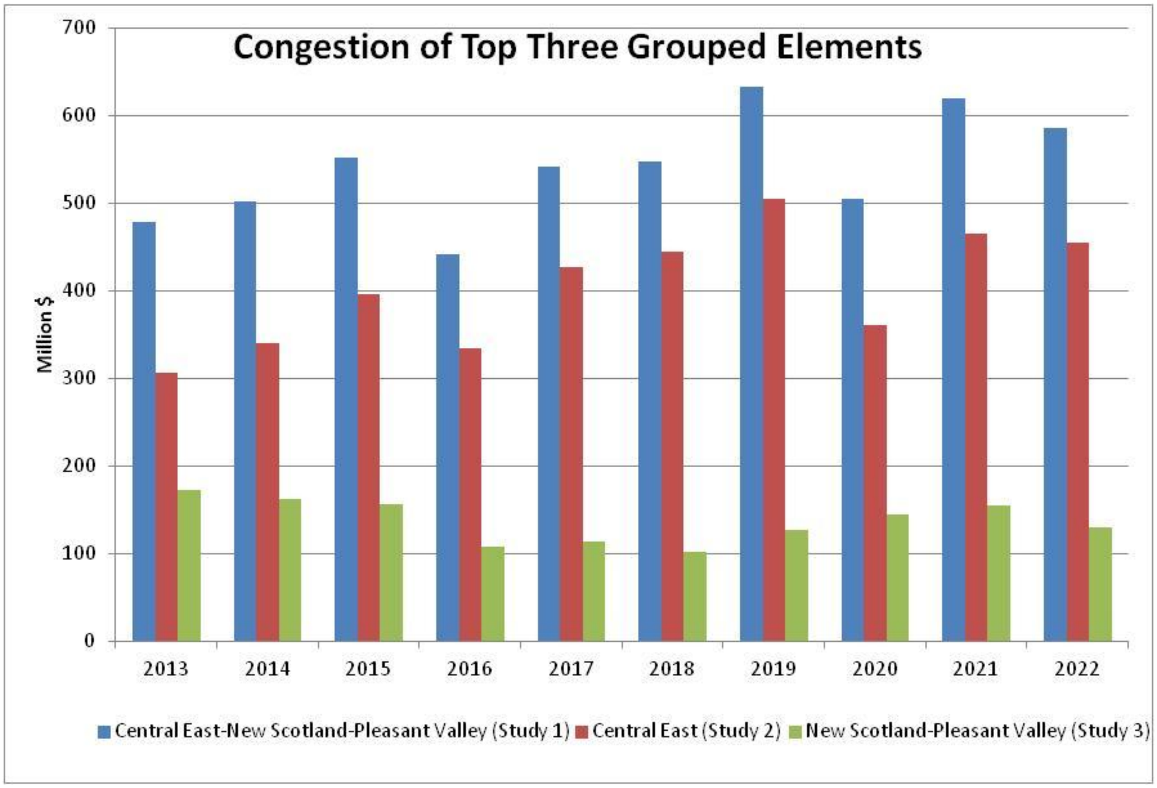


Figure 3: Projected Congestion on the Top Three CARIS Groupings (Nominal $M)

Tariff provisions direct that the CARIS analysis study four solution types for each of the selected studies (i.e., transmission, generation, demand response and energy efficiency) and that the studied solutions be comparable. To this end, the NYISO initially determined an appropriate transmission solution for each of the three studies based on its engineering judgment and a review of pending proposed transmission projects. Each generic transmission solution therefore consists of building a new 345 kV transmission line with a line rating of 1,986 MVA connecting the buses immediately upstream and downstream of the congested interface. For the CE-NS-PV and NS-PV interfaces, this resulted in an increased transfer capability of approximately 1,200 MW; for the CE interface, this resulted in an increased transfer capability of 550 MW.

The NYISO then analyzed a range of generation solutions that could be considered comparable to the transmission solution, based on the impact on demand congestion and production costs, and the impact on transfer limits. When compared with the generation solution, transmission solutions produce significantly higher impact on demand congestion for all three congestion corridors. However, except for Central East (CE), generation solution produces higher production cost savings in aggregate for the ten-year period. The results of these comparisons are presented in Appendix J. The generation solutions were sized comparable to the increase in transfer capability provided by the transmission solutions.

The sizes for the other solutions (energy efficiency and demand response) were similarly constructed such that the overall MW size was comparable to the increase in transfer capability associated with the transmission solution for the study in question.

Two of the study groups are nested with a southern terminus at Pleasant Valley; therefore, the generation solution for the CE-NS-PV and NS-PV studies was sited at Pleasant Valley. The NYISO modeled a new 1,320 MW combined cycle plant at this location. The generation solution for CE is a 660 MW unit sited at New Scotland, downstream of the Central East interface.

The energy efficiency solution is modeled by load reductions for the impacted load zones. For the CE-NS-PV and CE studies, the energy efficiency solution was modeled in F, G and J; for the NS-PV study, the solution was modeled in G and J. The demand response solutions were modeled in the same location and block sizes as the energy efficiency solutions, but only for the 100 peak hours.

Table 1 presents a summary of the solution sizes.

Table 1: Generic Solutions

Generic Solutions			
Studies	Study 1: Central East-New Scotland-Pleasant Valley	Study 2: Central East	Study 3: New Scotland - Pleasant Valley
Transmission			
Transmission Path	Edic to New Scotland to Pleasant Valley	Edic to New Scotland	New Scotland to Pleasant Valley
Miles (# of terminals)	150 (3)	85 (2)	65(2)
Generation			
Unit Siting	Pleasant Valley	New Scotland	Pleasant Valley
# of 330 Blocks	4	2	4
DR			
Locations (# of Blocks)	F (1) , G(1) and J(4)	F (1), G (1) and J (1)	G (1) and J (5)
Total # of 200 MW Blocks	6	3	6
EE			
Locations (# of Blocks)	F (1) , G(1) and J(4)	F (1) ,G (1) and J (1)	G (1) and J (5)
Total # of 200 MW Blocks	6	3	6

Costs for each type of generic solution were presented through the stakeholder process but no determination was made as to the feasibility of any generic solution. 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. In addition, it should be noted that the energy efficiency costs include only the utility program costs and do not include costs incurred by the utility customer to install and maintain the equipment. For the demand response solution, the costs do not reflect energy payments to demand-response providers participating in the NYISO's demand-response programs or any additional payments received through the utility program.

The present value of the estimated carrying costs for each of the generic solutions was compared to the present value of projected production cost savings for a ten-year period, yielding a benefit/cost ratio for each generic solution. The benefit/cost ratios displayed in Figure 1 are based on the cumulative present value in 2013 dollars of the NYCA-wide production cost savings over the ten year period as shown in Figure 4. For purposes of a relative order of magnitude comparison, nominal electric production costs of New York generators over the Study Period range between $3.9 billion and $7.0 billion annually.

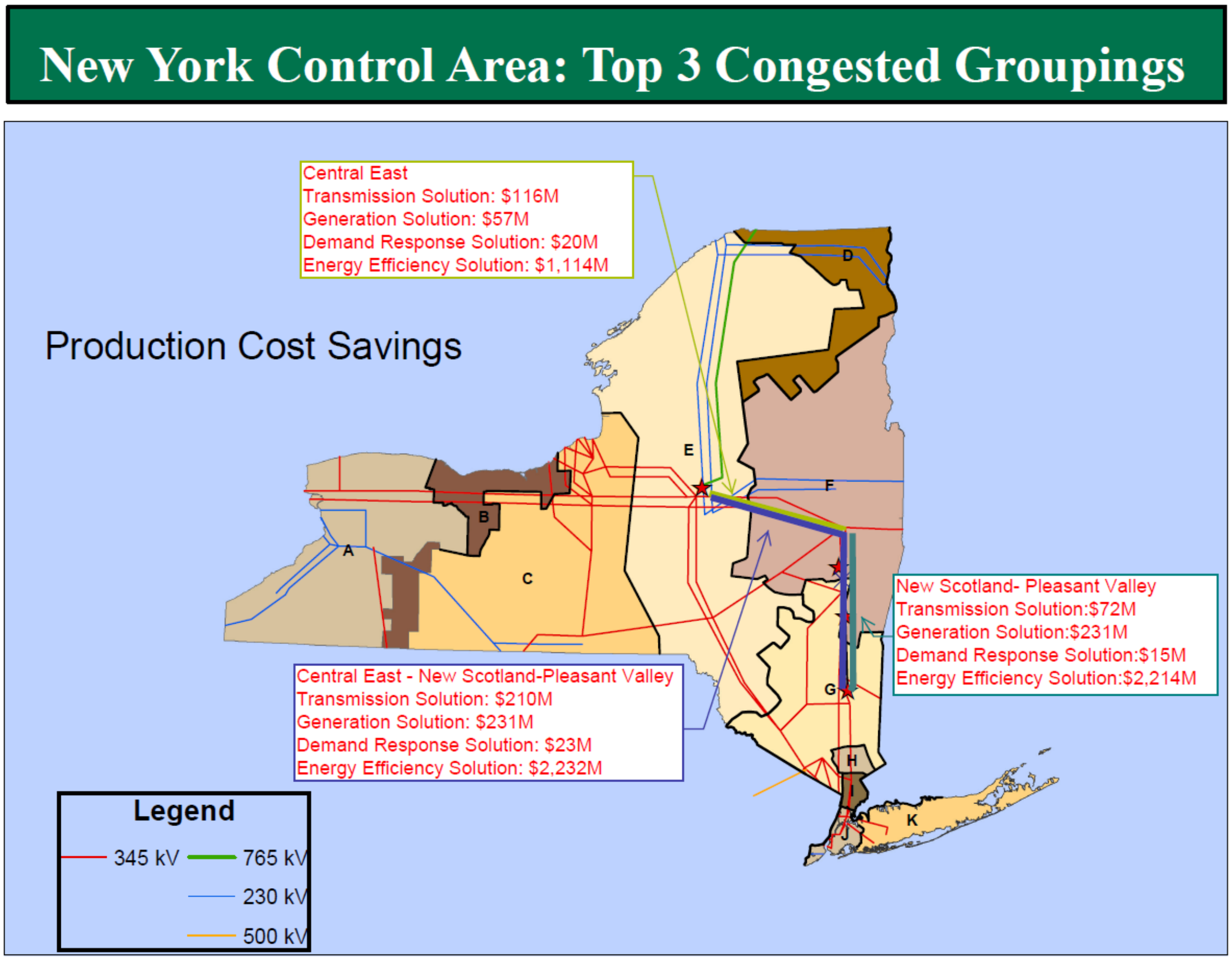


Figure 4: NYCA-wide Production Cost Savings (Present Value in 2013 $M)

B. Additional Metrics

In addition to the NYCA-wide production cost savings for each generic solution, the NYISO also has provided, for informational purposes, additional metrics for each of the three studies and each of the generic solutions in terms of changes in:

a. emission quantities and costs,

b. NYCA generator payments,

c. locational based marginal price (LBMP) load payments,

d. installed capacity (ICAP) savings,

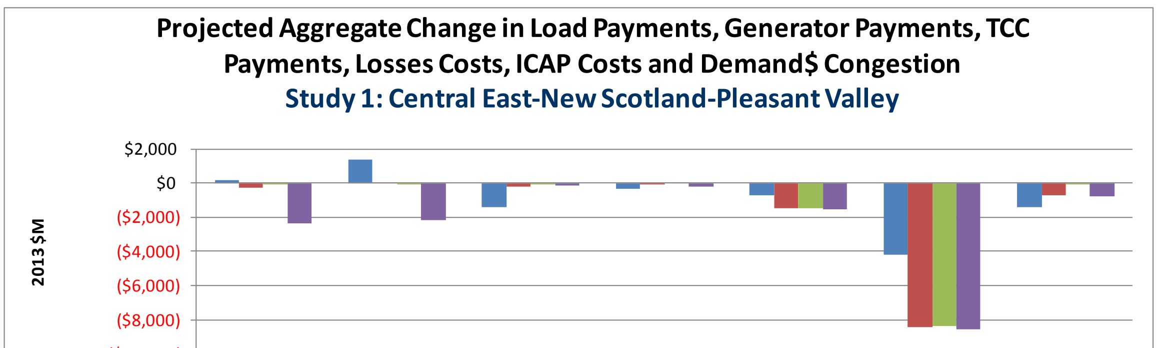
e. loss payments for losses on the transmission system, and

f. congestion rents or transmission congestion contracts (TCCs) payments.

All but the ICAP metric are results of the production cost simulation program and show either increases or decreases depending primarily on which solution is modeled. The ICAP metrics are computed using the latest available information from the installed reserve margin (IRM), locational capacity requirement (LCR), and ICAP Demand Curves.

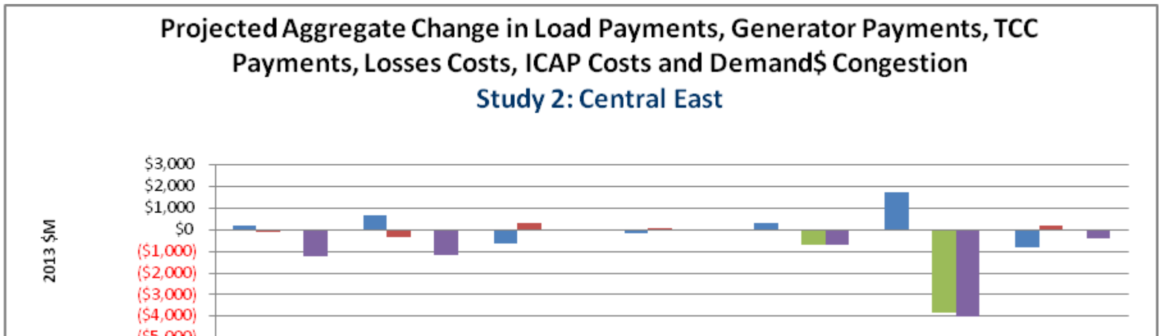
Figures 5 through 7 below present in graphical form the changes in the additional metric quantities for each of the three study cases. The total ten-year present value amounts for these metrics are presented in 2013 $M.

Negative numbers (shown in brackets) represent reductions in those metric quantities. Some metrics are not limited to payments made only by NYCA load nor to payments made only to NYCA generators. Load payments include export costs, and generator payments include import costs.



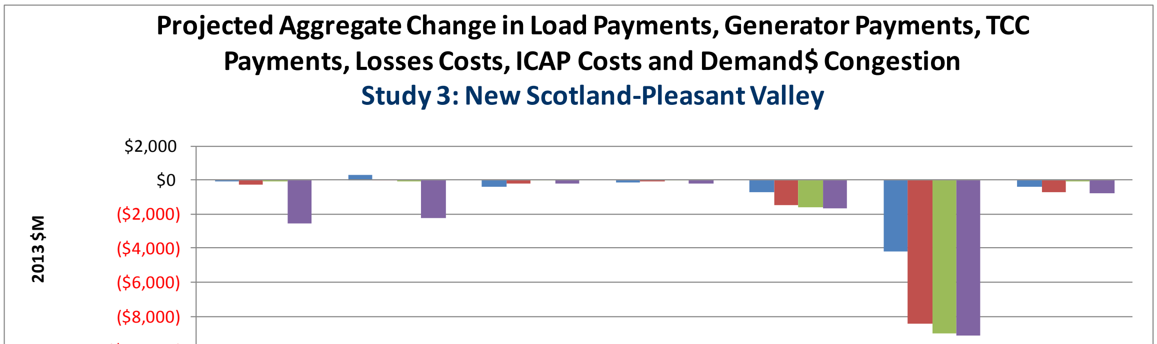
	Load Payments	Generator Payments	TCC Payments	Losses Costs	ICAP Variant 1	ICAP Variant 2	Demand$ Congestion
Transmission	$194	$1,382	($1,430)	($316)	($739)	($4,221)	($1,411)
Generation	($272)	$6	($217)	($14)	($1,501)	($8,406)	($683)
Demand Response	($96)	($100)	($2)	$5	($1,498)	($8,368)	($86)
Energy Efficiency	($2,368)	($2,173)	($129)	($209)	($1,536)	($8,572)	($761)

Figure 5: Changes in Metrics for Study 1



	Load Payments	Generator Payments	TCC Payments	Losses Costs	ICAP Variant 1	ICAP Variant 2	Demand$ Congestion
Transmission	$193	$687	($654)	($166)	$302	$1,739	($838)
Generation	($83)	($369)	$282	$41	$0	$0	$174
Demand Response	($47)	($40)	($10)	($2)	($672)	($3,841)	($30)
Energy Efficiency	($1,208)	($1,179)	($32)	($58)	($701)	($4,008)	($399)

Figure 6: Changes in Metrics for Study 2



	Load Payments	Generator Payments	TCC Payments	Losses Costs	ICAP Variant 1	ICAP Variant 2	Demand$ Congestion
Transmission	($61)	$309	($413)	($139)	($730)	($4,171)	($367)
Generation	($272)	$6	($217)	($14)	($1,501)	($8,406)	($683)
Demand Response	($70)	($86)	$9	$3	($1,613)	($8,980)	($61)
Energy Efficiency	($2,549)	($2,253)	($216)	($214)	($1,642)	($9,135)	($782)

Figure 7: Changes in Metrics for Study 3

Table 2 and Figure 8 present the change in emissions across the Study Period associated with each of the solutions for each of the studies.

Table 2: Projected Emissions Changes for the Three Studies

	SO2			CO2			NOx		
Generic Solutions	Tons	% Change	Cost ($M)	1000 Tons	% Change	Cost ($M)	Tons	% Change	Cost ($M)
Transmission									
Edic-New Scotland-Pleasant Valley	8,620	7.1%	$5.5	280	0.1%	$6.4	1,878	0.9%	$0.2
Edic-New Scotland	5,245	4.3%	$3.6	734	0.2%	$5.3	2,211	1.1%	$0.1
New Scotland-Pleasant Valley	1,420	1.2%	$1.1	-1,389	-0.4%	-$5.3	-1,156	-0.6%	$0.0
Generation									
Pleasant Valley	-6,445	-5.3%	-$3.6	9,463	2.8%	$68.4	-6,558	-3.1%	-$0.4
New Scotland	-3,895	-3.2%	-$2.2	4,223	1.3%	$27.9	-2,198	-1.1%	-$0.2
Pleasant Valley	-6,445	-5.3%	-$3.6	9,463	2.8%	$68.4	-6,558	-3.1%	-$0.4
Demand Response									
F (200), G (200), J (800)	-866	-0.7%	-$0.5	237	0.1%	$1.3	-224	-0.1%	$0.0
F (200), G (200), J (200)	-579	-0.5%	-$0.4	-84	0.0%	-$0.6	-237	-0.1%	$0.0
G (200), J (1000)	-608	-0.5%	-$0.4	429	0.1%	$2.6	-142	-0.1%	$0.0
Energy Efficiency									
F (200), G (200), J (800)	-5,514	-4.6%	-$3.4	-16,030	-4.8%	-$87.7	-6,437	-3.1%	-$0.4
F (200), G (200), J (200)	-2,966	-2.4%	-$1.6	-7,897	-2.4%	-$43.6	-3,237	-1.6%	-$0.2
G (200), J (1000)	-5,757	-4.8%	-$4.0	-16,342	-4.9%	-$88.8	-7,078	-3.4%	-$0.4

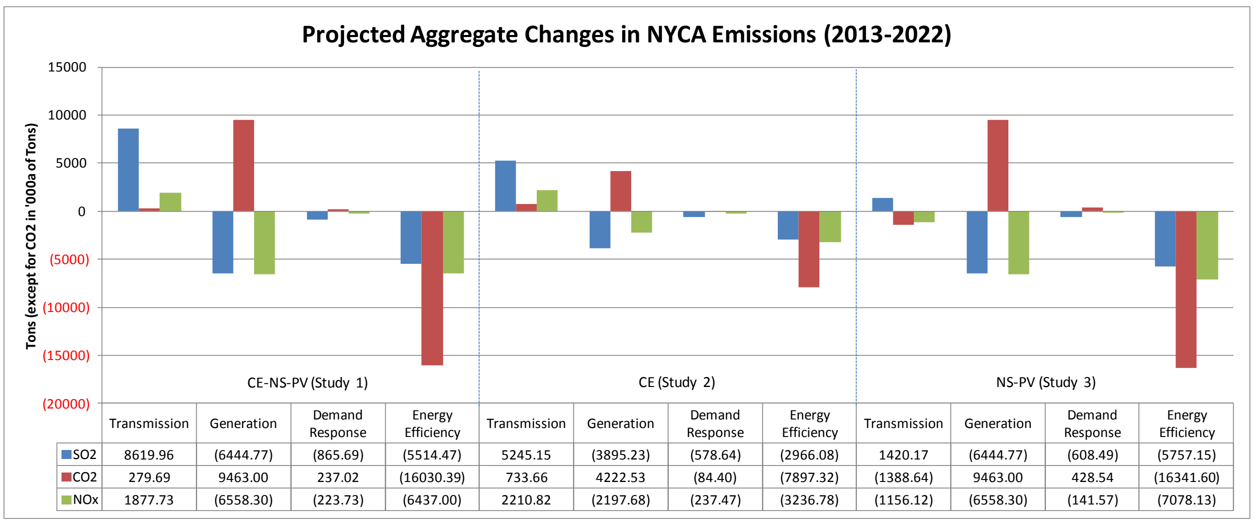


Figure 8: Projected Emissions Changes for Three Studies

C. Scenario Analysis

The NYISO conducted scenario analyses to evaluate the congestion impact of changing variables in the base case assumptions. Scenario analysis provides useful insight on the sensitivity of projected congestion values to differing assumptions included in the base case. Variations in some inputs may provide results that are consistent across NYCA, while other inputs may yield changes that are more localized. The scenarios were selected by the NYISO in collaboration with its stakeholders. They modify the base case to address potential regulatory changes in environmental emission requirements, full achievement of the State Renewable Portfolio Standard[3] and the State Energy Efficiency Portfolio Standard,[4] variations from the forecasted energy consumption and fuel prices, and the termination of the Athens SPS for the Study Period. These scenarios are each addressed individually; no cumulative impacts are determined.

Table 3 lists major assumptions used for each scenario; and Table 4 shows the cumulative impact on congestion for each scenario for the Study Period in 2013 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.

Table 3: Major Scenario Assumptions

Scenario	Variables
Implementation of Cross-State Air Pollution Rule (CSAPR)	Increases in NO_x and SO_2 costs as projected by EPA
Higher Load Forecast	4% higher (referred to as the Econometric Forecast in Tables I-3a and I-3b, *2013 Load and Capacity Data*)
Lower Load Forecast	5% lower (reflects full EEPS Goals achievement)
Full Main Tier RPS and Full EEPS Goals Achievement	Add approximately 2,300 MW of renewables from Interconnection queue and reduce 2015 coincident peak load to 32147 MW
Athens SPS Out of Service	2013-2022
Higher Natural Gas Prices	One standard deviation
Lower Natural Gas Prices	One standard deviation
Lower CO_2 Emission costs	$5/ton Ceiling
Higher Natural Gas costs in Midstate	Midstate & New England/ Upstate differential doubled
No National CO_2 Program	CO_2 Allowance Costs for non-RGGI states set to $0

3 NYSPSC CASE 03-E-0188. Order Regarding Retail Renewable Portfolio Standard. September 24, 2004.

4 NYSPSC CASE 07-M-0548. Order Establishing Energy Efficiency Portfolio Standard And Approving Programs. June 23, 2008. *id.,* Order Authorizing Efficiency Programs, Revising Incentive Mechanism, and Establishing a Surcharge Schedule, October 25, 2011; see also NYPSC Case 10-M00457, In the Matter of the Systems Benefits Charge IV, Order Continuing the System Benefits Charge, October 24, 2011.

Table 4: Scenarios Impact on Congestion: Ten-Year Study Period ($2013M)

Constraints	Scenarios: (Aggregate Change in Demand$ Congestion from Base Case) ($2013M)									
	CSAPR	Higher Load Forecast	Lower Load Forecast	Full RPS/EEPS Achievement	Athens SPS Out of Service	Higher Natural Gas Prices	Lower Natural Gas prices	Capped Carbon Prices	Higher Natural Gas Cost Differential	No National CO2 Program
Central East – New Scotland – Pleasant Valley	(232)	45	(66)	1,424	255	1,084	(1,487)	165	2,189	268
Central East	(218)	(113)	150	1,563	(153)	949	(1,354)	120	2,432	304
New Scotland-Pleasant Valley	(14)	158	(217)	(139)	408	135	(133)	46	(243)	(36)

Table 4 above shows the change in Demand$ Congestion from the scenarios for each of the most congested constraints.

3. Other Findings and Observations

- **Potential Impacts -** This report provides an economic analysis of projected congestion on the New York State bulk power transmission system and the potential costs and benefits of relieving that congestion. The study provides information to interested parties to consider developing transmission, generation, demand response or energy efficiency projects, as appropriate, to relieve congestion, and to propose transmission projects for economic evaluation and potential recovery of costs through the NYISO's Tariff. There are other potential benefits to relieving transmission congestion, such as reduced load payments, increased generator payments, reduced losses, ICAP savings, and reduced emissions that may be of interest to parties in making their investment decisions. For the purposes of this study, the load payment metric does not reflect that loads may be partially hedged through bilateral contracts and ownership of TCCs.

- **Demand$ Congestion** – As with the prior CARIS reports, the level of congestion projected in this 2013 CARIS Phase I Report will be less than historic levels. The disparity in large part is due to certain assumptions, operational parameters and market participant behavior. These disparities include market bidding behavior by both generators and load, virtual transactions that occur in the NYISO Day-Ahead Market, transmission outages, actual commodity price variations and hourly load variations. Similarly, congestion experienced in the future years will differ from the projected values because actual system operating conditions, economic conditions, fuel prices, environmental compliance costs and market behavior will be different from the study assumptions. The purpose of the production simulation model, however, is to help assess the effectiveness of congestion mitigation solutions and analyzes the impacts of these solutions under the same system conditions. The CARIS base case model projects the Demand$ Congestion values in New York at $643 million in 2013 and $929 million in 2021. Comparatively, historic Demand$ Congestion values from 2008 to 2012 ranged from a low of $765 million in 2012 to a high of $2,611 million in 2008.

- **Changes Since Last CARIS** – Changes were made in system assumptions and modeling since the 2011 CARIS. Among the changes that tend to decrease congestion are:

    a. a newly-executed agreement between National Grid and Athens Generating facility for which the Athens Special Protection System (SPS) was modeled as in service through the Study Period,

    b. a revision to the NYISO-PJM Joint Operating Agreement that increases the allocation of the Ramapo PAR flows,

    c. addition of expected downstate resources required to maintain system reliability, and

    d. lower carbon and NOx price forecasts.

- Major modeling changes for the 2013 study also include changes that could increase congestion, including:

    a. a higher load forecast,

    b. the introduction of a third New York natural gas price area for the Midstate area (Load Zones F-I), and

    c. refinements to the modeling of the Central East voltage limits.

  Additionally, the demand response and energy efficiency solutions were modeled as separate solutions for the first time in this CARIS to understand the impacts of these resources individually.

- **Resource Updates -** The ten-year assessment of future congestion and the potential benefits of relieving some of this congestion are based upon the new and existing NYCA resources that have been included in the base case for the 2012 Comprehensive Reliability Plan (CRP) to meet resource adequacy requirements. However, there were developments that occurred subsequent to the completion of the 2012 CRP, which were included among the factors considered by the 2013 CARIS. These include:

    a. Danskammer 1-6 were removed from the Base Case due to the units' retirement in January 2013,

    b. Dunkirk 1 was removed due to its retirement in June 2013 and Dunkirk 2 was removed beginning in June 2015,

c. Market-Based Solutions (MBS) and Reliability-Backstop Solutions (RBS) from the 2012 CRP were incorporated in order to maintain a reliable system throughout the Study Period.

- **External Load Forecasts –** In the 2011 CARIS, the forecasted loads for external control areas were held constant in order to maintain minimum reserve margins. In the 2013 CARIS, the NYISO utilized the forecasted values for the external loads and verified that reserve margins were at reasonable levels, i.e., 15%, throughout the Study Period.

- **Scenario Analyses -** Scenario analyses were used to provide projected congestion information associated with variations in load, fuel price, available resources, and other assumptions. The scenario analysis shows the impact on congestion for individual constraints.

- **Specific Solutions Will Produce Different Results -** Projects with characteristics other than the generic projects studied here could also relieve congestion. The generic solutions are representative, and are presented for informational purposes only, but their feasibility was not assessed.

- **Diversity of NYCA Impacts -** This study reports the benefits of relieving congestion both statewide and by zone across New York. All zones do not benefit equally when implementing the generic solutions. For example, load payments decreased in some zones and increased in others.

- **Benefit Lifespan -** The useful life of actual projects may be longer than the ten-year Study Period evaluated in this report pursuant to the NYISO tariff. Benefits and costs in later years can be considered in CARIS Phase 2.

4. 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 January 2014, subject to the approval of this 2013 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 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.

Subsequent to meeting 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.

1. Introduction

Pursuant to Attachment Y of its Open Access Transmission Tariff (OATT, or the Tariff), the NYISO performed the first phase of the 2013 Congestion Assessment and Resource Integration Study (CARIS). The study assesses both historic[5] and projected congestion on the New York bulk power system and estimates the economic benefits of relieving congestion. Together with the Local Transmission Planning Process (LTPP) and the Comprehensive Reliability Planning Process (CRPP), the CARIS is the final process in the NYISO's biennial Comprehensive System Planning Process (CSPP) (see Figure 1-1). The 2013 CARIS completes the CSPP process that began with LTPP inputs for the 2012 Reliability Needs Assessment.

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

This final report presents the 2013 CARIS Phase 1 study results and provides objective information on the nature of congestion in the NYCA. Developers can use this information to decide whether to proceed with transmission, generation, or demand response projects. Developers of such projects may choose to pursue them on a merchant basis, or to enter into bi-lateral contracts with LSEs or other parties**.** This report does not make recommendations for specific projects, and does not advocate any specific type of resource addition or other actions.

Developers may propose economic transmission projects for regulated cost recovery under the NYISO's Tariff and proceed through the Project Phase, CARIS Phase 2, which will be conducted by the NYISO upon request and payment by a Developer. Developers of all other projects can request that the NYISO conduct an additional CARIS analysis at the Developer's cost to be used for the Developer's purposes, including for use in an Article VII, Article X or other regulatory proceedings. For a transmission project, the NYISO will determine whether it qualifies for regulated cost recovery under the Tariff. Under CARIS, to be eligible for regulated cost recovery,

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

an economic transmission project must have production cost savings greater than the project cost (expressed as having a benefit to cost ratio (B/C) greater than1.0), a cost of at least $25 million, and be approved by at least 80% of the weighted vote cast by New York's Load Serving Entities (LSEs) that serve loads in Load Zones that the NYISO identifies as beneficiaries of the transmission project. The beneficiaries are those Load Zones that experience net benefits measured over the first ten years from the proposed project commercial operation date. After the necessary approvals, regulated economic transmission projects are eligible to receive cost recovery from these beneficiaries through the NYISO Tariff provisions once they are placed in service.

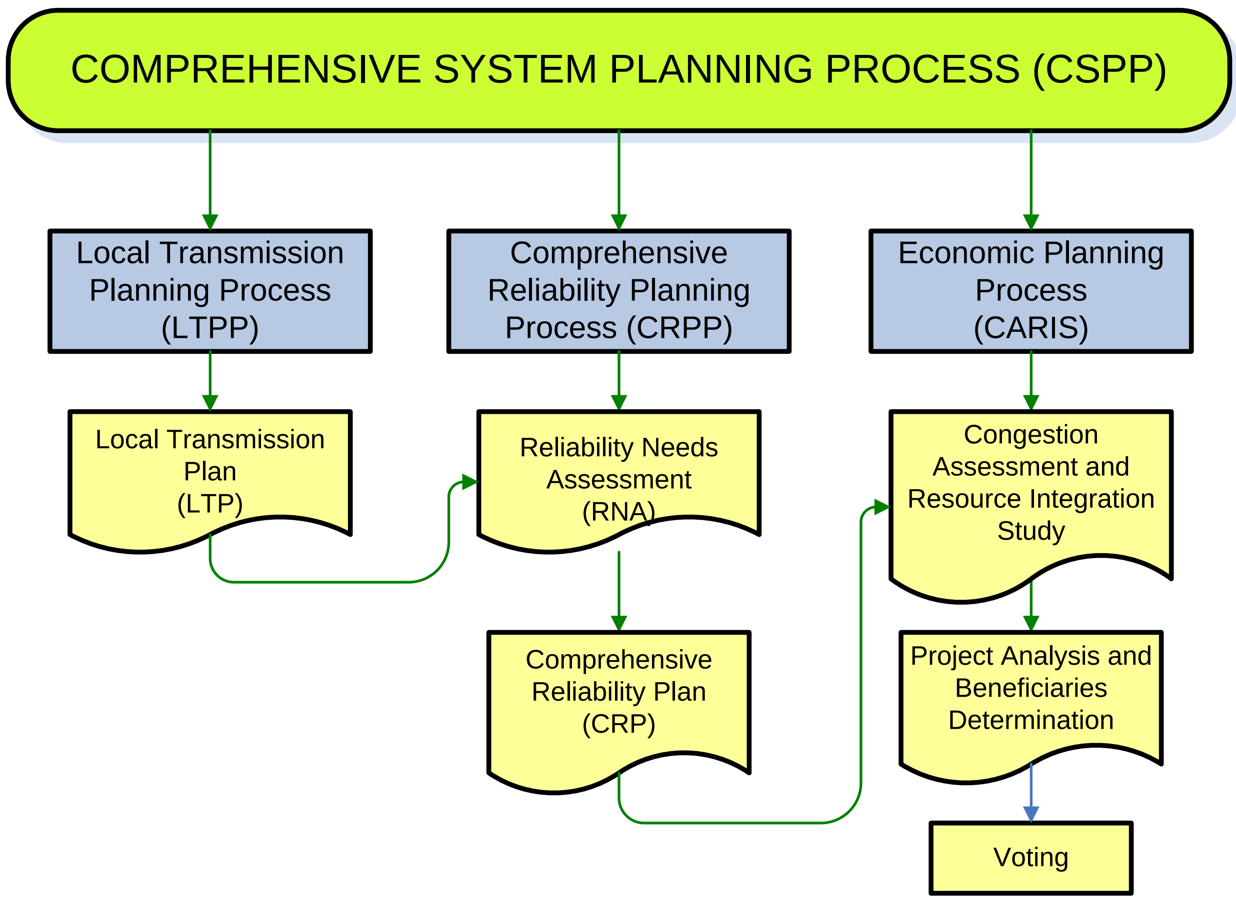


Figure 1-1: NYISO Comprehensive System Planning Process

This 2013 CARIS Phase 1 study includes intended enhancements to the 2011 CARIS Phase 1 study with respect to assumptions, modeling, and methodology for evaluating benefits. Such enhancements were discussed with ESPWG. Some of these changes reflect actual system changes while others are improvements. For example, based upon a newly-executed agreement between National Grid and Athens Generating facility, the Athens Special Protection System (SPS) was modeled as in service through the Study Period. The modeling of fuel costs were improved with the introduction of a third New York fuel area for the Midstate area, and the generic solutions were improved by modeling demand response separately from energy efficiency resources.

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, energy efficiency and demand response). 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 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 Director for approval.

2. Background

2.1. 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 2-1 below.

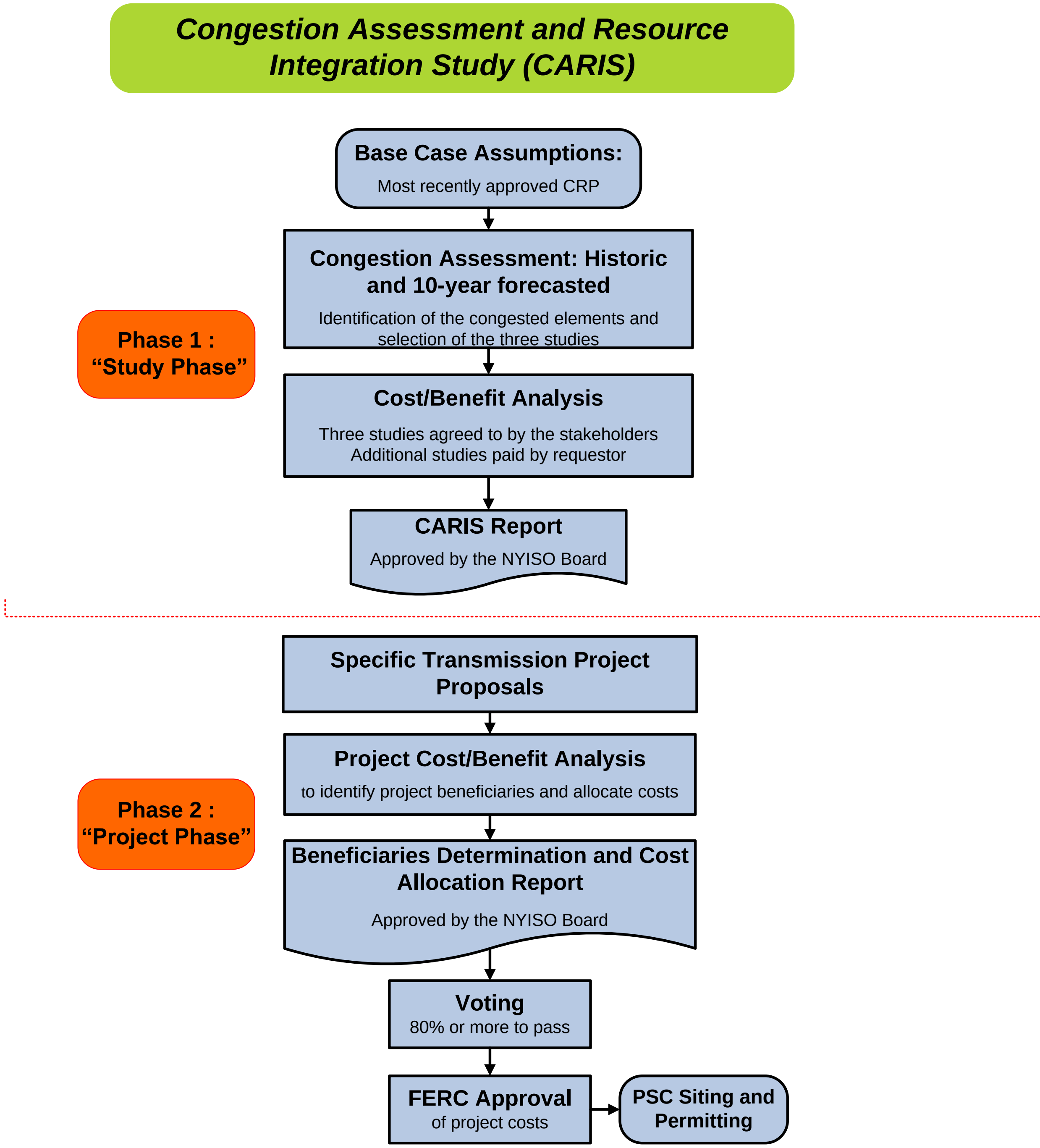


Figure 2-1: Overall CARIS Diagram

2.1.1. Phase 1 - Study Phase

In Phase 1 of the CARIS process, the NYISO, in collaboration with Market Participants, identifies the most congested elements in the New York bulk power system and conducts three 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 seven 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 top three ranked elements or groupings become the subjects of the three CARIS studies. For each of these three studies the NYISO conducts a benefit/cost analysis of generic solutions. All resource types - generation, transmission, energy efficiency and demand-response - are considered on a comparable basis as generic solutions to congestion. The solutions analyzed are not specific projects, but rather represent generic transmission, generation, energy efficiency, demand response 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 Section 3.

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 Demand$ Congestion on the three study elements or groupings, as well as other constraints throughout NYCA.

2.1.2. 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. The Phase 2 database will be updated, consistent with the CARIS manual, to reflect all appropriate and agreed system modeling changes required for a 10 year extension of the model. Such modeling changes may include, but are not limited to, changes to hurdle rates and the modeling of mothballed units. 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 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. LSE costs within a zone will be allocated according to the ratio of its load to all of the load in the zone - both expressed in MWh.

In addition to the NYCA-wide production cost savings metric and the net LBMP load savings metric, the NYISO will also provide additional metrics, for information purposes only, to estimate the potential benefits of the proposed project and to allow LSEs to consider other metrics when evaluating or comparing potential projects. These additional metrics will include estimates of reductions in losses, changes in LBMP load payments, changes in generator payments, changes in Installed Capacity (ICAP) costs, changes in emissions costs, and changes in TCC revenues. The TCC revenue metric that will be used in Phase 2 of the CARIS process is different from the TCC payment metric used in Phase 1. In Phase 2, the TCC revenue metric will measure reductions in estimated TCC auction revenues and allocation of congestion rents to the TOs (for more detail on this metric see Section 3.2.2 of this report and the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual.[6])

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 possible changes in load forecasts, fuel prices and environmental regulations, as well as other qualitative impacts such as improved system operations, other environmental impacts, and integration of renewable or other

[6]See http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/Economic_Planning_Process_Manual_Final_12-05-12.pdf

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 1.2.5 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.

3. CARIS Methodology and Metrics

3.1. CARIS Methodology

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

In prior CARIS Phase 1 studies, the NYISO had utilized the Portfolio Ownership and Bid Evaluation (PROBE) production cost simulation tool, developed by PowerGEM LCC, to perform the NYISO historic congestion analysis. However, in January 2012, the NYISO began using 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 these 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.

3.2. CARIS Metrics

The principal benefit metric for 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 7.33% used for the present value analysis was the current weighted average cost of capital for the NYTOs, weighted by their annual GWh load in 2012.

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 what has been used for the reporting of historic congestion for the past nine years. Demand$ Congestion is used to identify and rank the significant transmission constraints as candidates for grouping and the evaluation of potential generic solutions. It does not equate to payments by load.

3.2.1. Principal Benefit Metric[7]

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 2011 CARIS analysis. Specifically, the NYCA-wide production cost savings are calculated using the following formula:

NYCA-wide Production Cost Savings =

NYCA Generator Production Cost Savings -

$$\sum \left[(\textit{Import/Export Flow})_{Solution} - (\textit{Import/Export Flow})_{Base}\right] \times \textit{ProxyLMP}_{Solution}$$

Where:

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

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

3.2.2. Additional Benefit Metrics

The additional benefits, which are provided for information purposes only, include estimates of reduction in loss payments, LBMP load costs, generator payments, ICAP costs, emission costs, and TCC payments. All the quantities, except ICAP, will be the result of the forward looking production cost simulation for the ten-year planning period. The NYISO, in collaboration with the ESPWG, determined the additional informational metrics to be defined for this CARIS cycle given 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

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

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.

4. Baseline System Assumptions

The implementation of the CARIS process requires the gathering, assembling, and coordination of a significant amount of data, in addition to that already developed for the reliability planning processes. The 2013 CARIS study process is conducted by updating the base case input assumptions provided in the 2012 CRP and aligns with the ten-year reliability planning horizon for the 2012 CRP.

4.1. Notable System Assumptions & Modeling Changes

The base case has been updated as of May 1, 2013 for this CARIS Phase 1 using the assumptions provided below. These 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. Because assumptions are used in the study, the actual results may differ from those projected in this study. The key assumptions are presented below:

1. The load and capacity forecast was updated using the 2013 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 2012 CRP power flow base cases were updated for use in the 2013 CARIS study.

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 2012 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.

In addition to the modeling changes listed below that can have significant impacts on the congestion projections, there are both known NYCA events as well as projected events, which were modeled by the NYISO in the base case in accordance with the requirements of the Tariff, that have impacts on the simulation outcome, as summarized in Table 4-1.

Major Modeling Inputs

Input Parameter	Change from the 2011 CARIS
Load Forecast	Higher
Natural Gas Price Forecast	Higher by end of Study Period
Carbon Price Forecast	Lower
NOx Price Forecast	Lower
SOx Price Forecast	Higher
Hurdle Rates	Lower

Modeling Changes

Description	Change from the 2011 CARIS
MAPS Software Upgrades	Latest GE MAPS Version 12.407E 05/03/13 Release was used for production cost simulation.
IMO-MISO Loop Flow Limit	The limit was updated to the historic limits scheduled in SCUC (+150MW to -350MW counter clockwise)
Central East Interface Limit	The nomogram to determine the voltage limit based on the commitment of the Oswego complex units was reviewed and enhanced.[8]
Ramapo PARs	Modeling algorithm was adjusted to reflect revised NYISO-PJM Joint Operating Agreement, directing that 61% of AC flows occur across Ramapo PARS.
Fuel price forecast	Added additional natural gas pricing point for Midstate area (Zones F-I) with fuel costs proxied by Tennessee Zone 6 hub price. The Downstate natural gas price forecast also accounts in the near-term for the completed construction of the Spectra pipeline and the associated increase in supply to the region.

[8] The Oswego complex consists of Oswego 5 and 6, Fitzpatrick, Nine Mile 1 and 2, and Sithe Independence. See http://www.nyiso.com/public/webdocs/markets_operations/market_data/power_grid_info/CE_VC_Static_limit_posting.pdf for details on the Central East voltage limit component values.

CRPP Market-Based and Reliability-Backstop Solutions	Incorporated MBS and RBS solutions from 2012 CRP required to maintain reliable system
PJM Representation Expanded	Expanded the modeled PJM system to include First Energy American Transmission Systems Inc. (FE-ATSI) and Duke Ohio and Kentucky (DEOK) which joined the PJM Market in 2011
IESO Representation Improved	Increased granularity of load representation through modeling of 10 load zones in IESO
ISO-NE Representation Improved	Increased granularity of load representation through modeling of 13 load zones in IESO
Emission Modeling Refinement	Accounted for seasonal NOx allowance Costs, incremental emission rates (reflecting differing emission rates at different unit output levels), and exemption of certain generators (e.g., <25 MW, waste-to-energy) from allowance costs.
Athens SPS[9]	Consistent with the agreement between National Grid and the Athens generating facility, the Athens SPS is modeled in service throughout the Study Period.

[9] The SPS may come out of service at the end of the ten-year period or earlier if a Permanent Physical Reinforcement (PPR) is installed and operational.

Table 4-1: Timeline of NYCA Changes (including RBS and MBS)[10]

Year	Year-to-Year Changes
2013	Danskammer 1 -6 retired; Montauk Units #2, #3 and #4 retired;Niagara Bio-Gen retired; Dunkirk 1 retired; Stony Creek Wind Farm in service (94.4 MW);Stewart's Bridge Hydro re-rate (3.0 MW); Nanticoke Landfill re-rate (1.6 MW); HTP in service;revised PJM-NYISO JOA governing Ramapo PARS; modeling of Athens SPS in-service.
2014	No Changes
2015	Dunkirk 2 retired (June 2015)
2016	500 MW of Astoria Repowering project in service; approx. 100 MWs of Astoria GTs retired (MBS)
2017	No Changes
2018	500 MW of Astoria Repowering project in service; approx. 495 MWs of Astoria GTs retired (MBS)
2019	No Changes
2020	No Changes
2021	300 MW Generation (RBS) -- 100 MWs in G, J and K
2022	275 MW Increase in UPNY-SENY (RBS)

4.2. Load and Capacity Forecast

The load and capacity forecast used in the CARIS base case, provided in Table 4-2, was based on the 2013 Gold Book and accounts for the impact of programs such as the Energy Efficiency Portfolio Standard (EEPS). Appendix C contains similar data, broken out by fuel type, for the modeled external control areas.

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

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Peak Load (MW)											
NYCA		33,279	33,725	34,138	34,556	34,818	35,103	35,415	35,745	36,068	36,355
Zone J		11,485	11,658	11,832	12,006	12,137	12,266	12,419	12,572	12,725	12,833
Zone K		5,421	5,471	5,514	5,592	5,616	5,663	5,729	5,802	5,878	5,958
Resources (MW)											
NYCA	Capacity	40,048	39,973	39,973	40,322	40,322	40,418	40,418	40,418	40,718	40,718
	SCR	1558	1558	1558	1558	1558	1558	1558	1558	1558	1558
	Total	41,606	41,531	41,531	41,880	41,880	41,976	41,976	41,976	42,276	42,276
Zone J	Capacity	10,150	10,150	10,150	10,574	10,574	10,669	10,669	10,669	10,769	10,769
	SCR	543	543	543	543	543	543	543	543	543	543
	Total	10,693	10,693	10,693	11,117	11,117	11,212	11,212	11,212	11,312	11,312
Zone K	Capacity	5,914	5,914	5,914	5,914	5,914	5,914	5,914	5,914	6,014	6,014
	SCR	127	127	127	127	127	127	127	127	127	127
	Total	6,041	6,041	6,041	6,041	6,041	6,041	6,041	6,041	6,141	6,141

Source: 2013 Gold Book baseline load forecasts from Section I.[11]

[10] For the purpose of this CARIS Phase 1 study, Cayuga 1 and 2 were assumed to be in service throughout the Study Period. While the units' owners had submitted notification of their intent to mothball the units to the NYISO, the NYSPSC and other interested parties, it was determined that the units' continued operation was required to meet local reliability needs in the absence of transmission upgrades. No firm plans for transmission upgrades were included in the Transmission Owner's Local Transmission Plan (LTP) as part of its 2013 Gold Book submission; therefore, to maintain a reliable system, the NYISO determined that it was necessary to retain the Cayuga units in the Base Case.

[11] NYCA "Capacity" values include resources internal to New York, additions, re-ratings, retirements, purchases and sales, and UDRs with firm capacity. Zones J and K capacity values include UDRs for the entire capacity of the controllable lines consistent with the 2012 RNA.

4.3. Transmission Model

The CARIS production cost analysis utilizes a bulk power system representation for the entire Eastern Interconnection, which is defined roughly as the bulk electric network in the United States and Canadian Provinces East of the Rocky Mountains, excluding WECC, and Texas. Figure 4-1 below illustrates the 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.

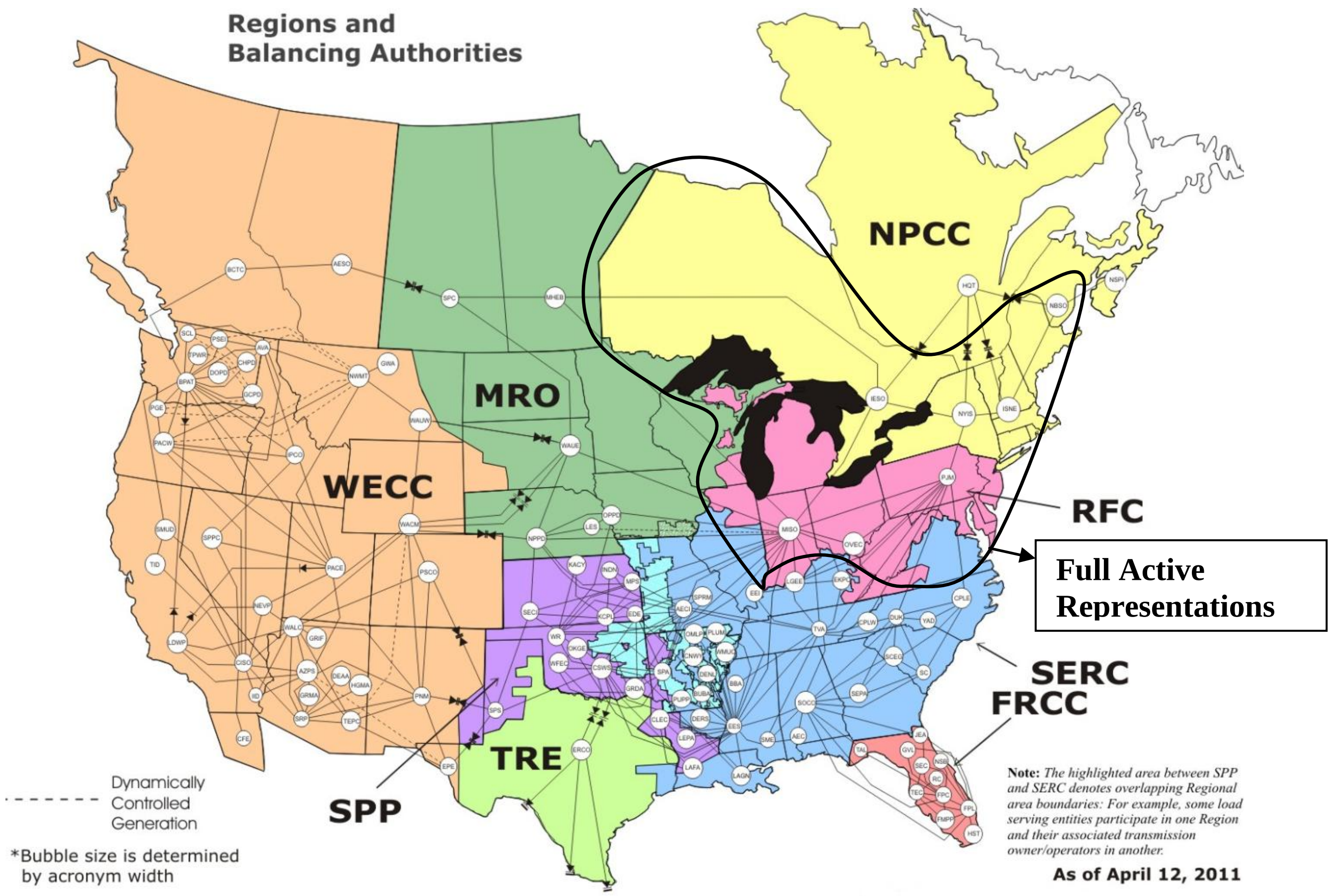


Figure 4-1: Areas Modeled in CARIS (Excluding WECC, FRCC, SPP, & TRE)

Source: NERC

4.3.1. 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 determine the changes in NYCA and locational reserve margins due to each of the modeled solutions. For voltage and stability based limits the normal and emergency limits are assumed to be the same. For NYCA Interface Transfer limits, the limits are consistent with the SCUC operating limits and operating nomograms with some exceptions as indicated in Table 4-3 below.

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

Interface	2013 CARIS Study
WEST CENTRAL-Open	2150
CENTRAL EAST	2955[12]
ConEd - Long Island	2166
Sprainbrook/Dunwoodie South	5365

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

Normal thermal interface transfer limits for the CARIS study are not directly utilized from the thermal transfer analysis performed using the Power Technologies Inc. Managing and Utilizing System Transmission (MUST) software application. Instead, CARIS uses the most limiting monitored line and contingency sets identified from MUST analysis. The resulting monitored lines and contingency sets used in the CARIS do not include lines that have less than a 5% impact on the NYCA cross-state transmission interfaces, or the lines that only impact local 115-138 kV transmission or sub-transmission constraints.

4.4. Fuel Forecasts

4.4.1. CARIS Base Annual Forecast

The fuel price forecasts for CARIS are based on the U.S. Energy Information Administration's (EIA)[13] current national long-term forecast of delivered fuel prices, which is released each spring as part of the Annual Energy Outlook (AEO). The figures in this forecast are in real dollars (i.e., indexed relative to a base year). Forecasted time-series of the GDP deflator published by EIA, as part of the AEO, were used to inflate the *real* values to *nominal* values.

4.4.2. New York Fuel Forecast

In developing the New York fuel forecast, adjustments were made to the EIA fuel forecast to reflect bases for fuel prices in New York. Key sources of data for estimating the relative differences or 'basis' for fuel prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on the information

[12] Base limit. See http://www.nyiso.com/public/webdocs/markets_operations/market_data/power_grid_info/CE_VC_Static_limit_posting.pdf.

[13] www.eia.doe.gov

collected through Form EIA-923.[14] The base annual forecast series from the EIA 2013 annual energy outlook forecast are then subjected to an adjustment to reflect the New York ‘basis’ relative to the national prices as described below.

Natural Gas

Analysis of EIA’s Short-Term Energy Outlooks from the past five years for the national average of delivered price of natural gas for electricity generation suggests that it is, on average, 10% higher than Henry Hub prices. The regional differential, that is, the differential between the regional natural gas and the national average, is calculated as the difference between the historic regional price and 110% of Henry Hub prices. The natural gas price for “Downstate” (Zones J and K), is the Transco Zone 6 (New York) hub-price[15], for “Midstate” (Zone F through I), is Tennessee Zone 6, and for “Upstate” (Zones A through E) the proxy-hub is the Tetco-M3. As of January 2013, the forecasted Downstate natural gas price is roughly 16.2% higher relative to the national average, the Midstate natural gas price is 21.6% higher than the national average and the Upstate natural gas price is 6.2% higher than the national average. The Midstate differential reflects recent trends and accounts for the impact of increased supply limitations and pipeline constraints on Tennessee Zone 6 and Algonquin Citygate prices. Reflecting an increase in supply due to the Spectra and Williams expansions, the Downstate differential with the national average is projected to gradually decrease from 16.4% in 2013 to 10% in 2018; increases back to 16.4% in 2021. Forecasted fuel prices for Upstate, Midstate and Downstate New York are shown in Figures 4-2, 4-3 and 4-4.

Fuel Oil

Based on EIA data published in Electric Power Monthly, price differentials across states and localities can be explained by a combination of transportation/delivery charges and taxes during the 24 month period ending May 2011. According to Electric Power Monthly, the trend of fuel-oil prices for New York implies that, on average, they are 5% below the national average delivered price. Based on this, the basis for both distillate and residual oils for Downstate are 0.95 (relative to the national average). The Upstate basis is 0.98 to reflect the additional transportation costs. For illustrative purposes, forecasted prices for Distillate Oil (Fuel Oil #2) and for Residual Oil (Fuel Oil #6) are shown in Figures 4-2, 4-3 and 4-4.[16]

[14] 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.
[15] The raw hub-price is ‘burdened’ by an appropriate level of local taxes.
[16] The observed, abnormal pattern of relative distillate and residual fuel oil prices forecasted for 2013 does not materially impact the study results, given the low price of natural gas relative to both fuel oils.

Coal

The data from Electric Power Monthly for the average cost of coal delivered for electricity generation was used to calculate a common basis for all NYCA Zones. Prices in New York are, on average, 36% higher than in the United States as a whole. (The published figures do not make a distinction between the different varieties of coal; *i.e.*, bituminous, sub-bituminous, lignite, etc.). EIA's 2013 AEO forecast is used for CARIS.

4.4.3. Seasonality and Volatility

All average monthly fuel prices, with the exception of coal and uranium, display somewhat predictable patterns of fluctuations over a given 12-month period. In order to capture such seasonality, NYISO estimated seasonal-factors using standard statistical methods.[17] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

The 2013 data used to estimate the seasonal factors are as follows:

- Natural Gas: Raw daily prices from ICE (Intercontinental Exchange) for the trading hubs Transco Zone 6 (New York) - as a proxy for Downstate (Zones J and K) – Tennessee Zone 6 – as a proxy for Midstate (Zones F to I) – Tetco-M3 – as a proxy for Upstate (Zones A to E).
- Fuel Oils #2 and #6: The average daily prices from Argus, Bloomberg, and Platts.

The seasonalized time-series represents the forecasted trend of average monthly prices.

[17] This is a two-step process: First, deviations around a centered 12-month moving average were calculated over the 2008-2012 period; second, the average values of these deviations were normalized to estimate monthly/seasonal factors.

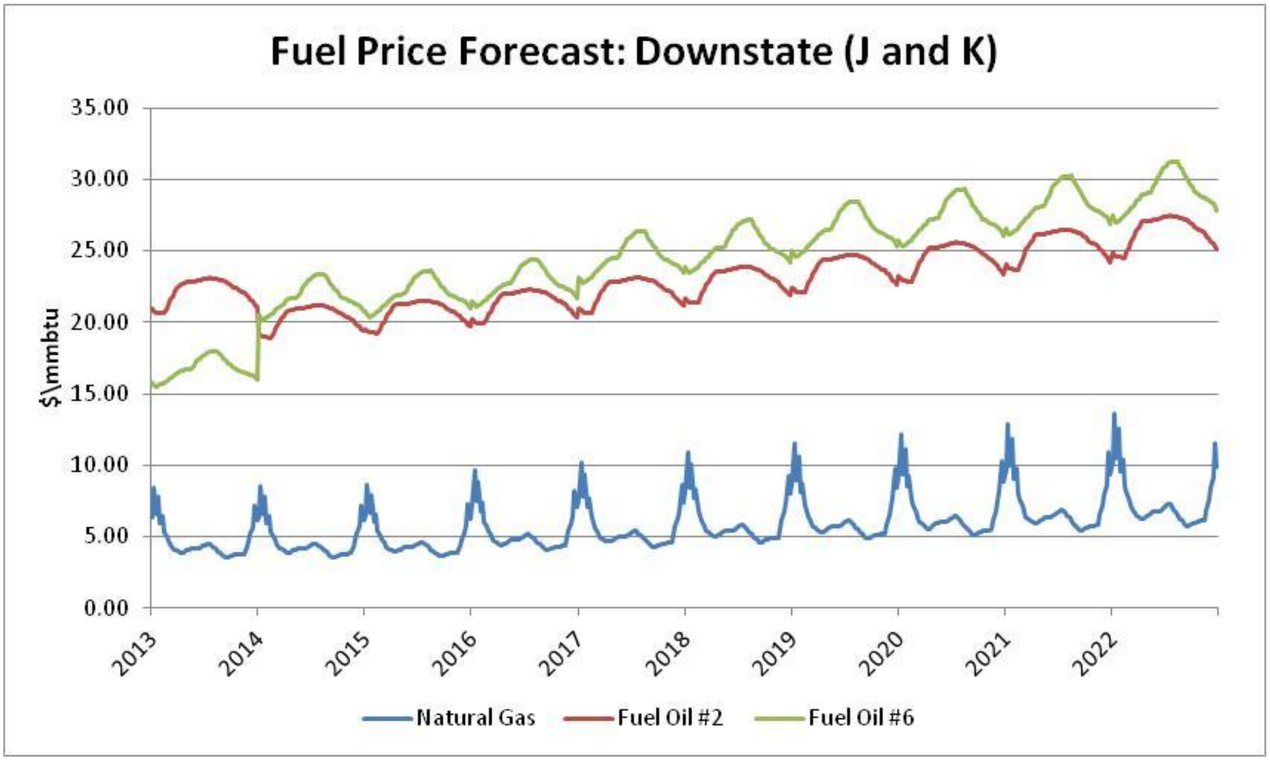


Figure 4-2: Forecasted fuel prices for Zones J & K (nominal $)

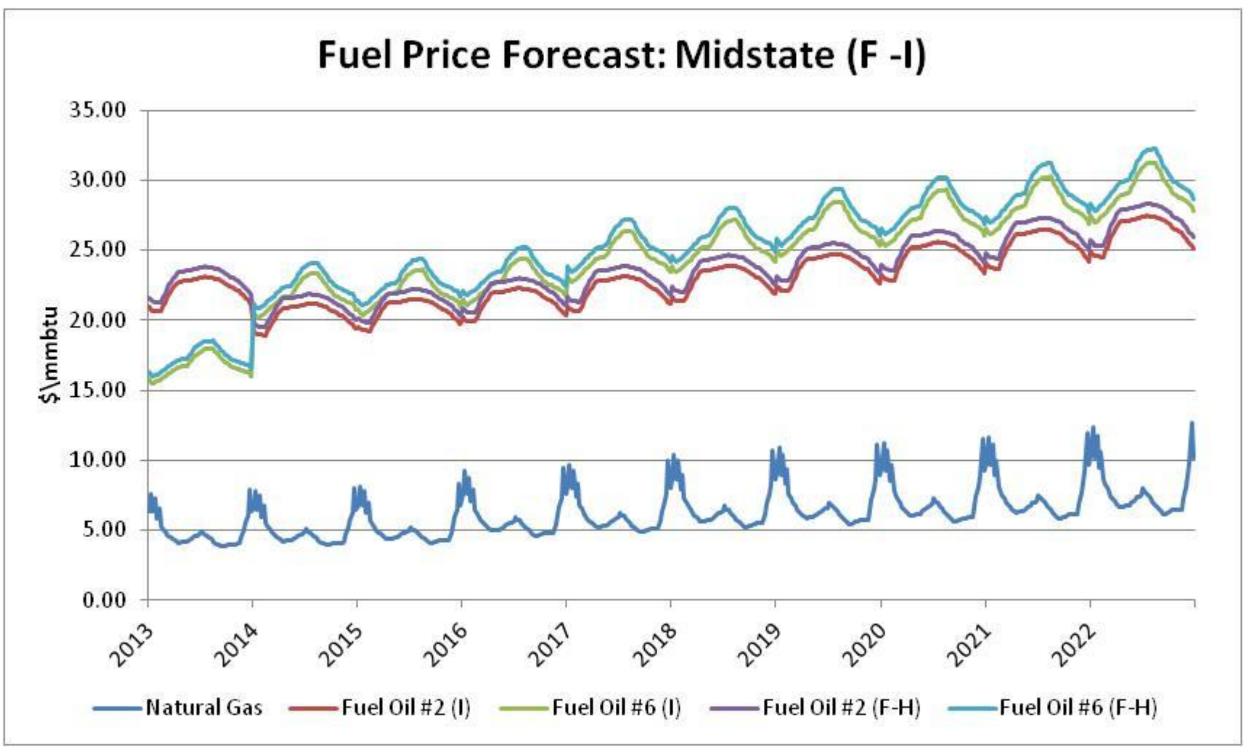


Figure 4-3: Forecasted fuel prices for Zones F-I (nominal $)

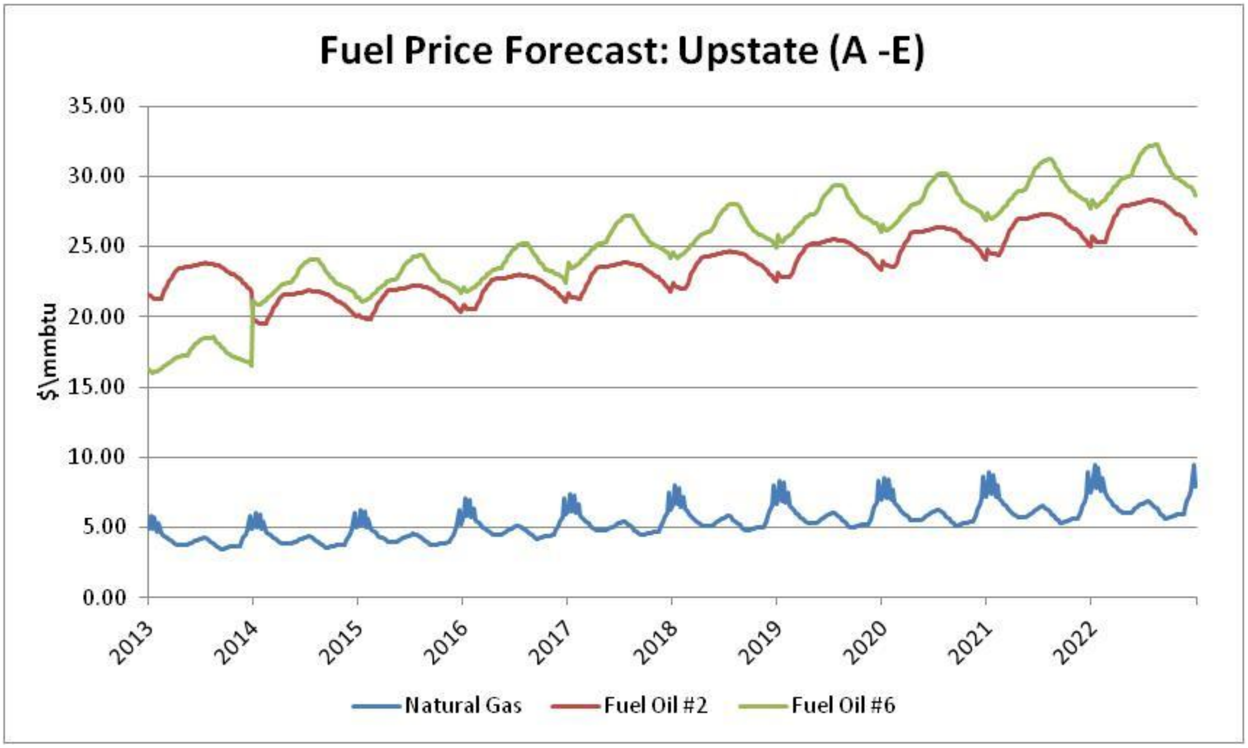


Figure 4-4: Forecasted fuel prices for Zones A-E (nominal $)

4.4.4. External Areas Fuel Forecast

The fuel forecasts for the three external areas, ISO-NE, PJM, and IESO, were also developed. For each of the fuels, the basis for ISO-NE, PJM-East, and PJM-West were based on the state level data published in Electric Power Monthly. With respect to IESO, the relative prices were based on data from a recent publication.[18]

4.5. Emission Cost Forecast

The costs of emission allowances are an increasing portion of generator production costs. Currently, all NYCA fossil fueled generators greater than 25 MW and

[18] Ontario Wholesale Electricity Market Price Forecast For the Period May 1, 2013 through October 31, 2014, Presented to Ontario Energy Board, March 28, 2013 by Navigant Consulting Inc., Toronto, Ontario.

most generators in most surrounding states are required to hold allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2.

In July 2011 the USEPA finalized the Cross-State Air Pollution Rule (CSAPR) which would have required significant additional reductions of SO_2 and NO_X emissions beyond those previously identified. Before taking effect, the rule was stayed, and ultimately vacated, by the US District Court of Appeals for the District of Columbia. The USEPA has appealed the DC Circuit's ruling to the Supreme Court, which has accepted the petition and will begin hearing oral arguments during its next term, October 2013 – June 2014. Because of the uncertainty surrounding the CSAPR a decision was made, in consultation with the ESPWG, not to incorporate the rule. However, the impact of the CSAPR is analyzed as a scenario in this report.

Base Case allowance prices for annual and seasonal NO_X (throughout the Study Period) and SO_2 (2013-2015) are developed using prices representative of the currently traded Clean Air Interstate Rule (CAIR) NO_X and SO_2 allowances, escalated at nominally the same rate as natural gas prices.

USEPA's Mercury and Air Toxics Standard (MATS), requiring reductions in mercury, acid gas and particulate matter emissions, was finalized in December 2011. The standard will take effect in March 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, as a reduction in one will invariably accompany a reduction in the other. While the rule takes a command and control approach to lowering emissions, USEPA posits in the rulemaking that the vast 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 used as a proxy for the costs of MATS beginning in 2016.

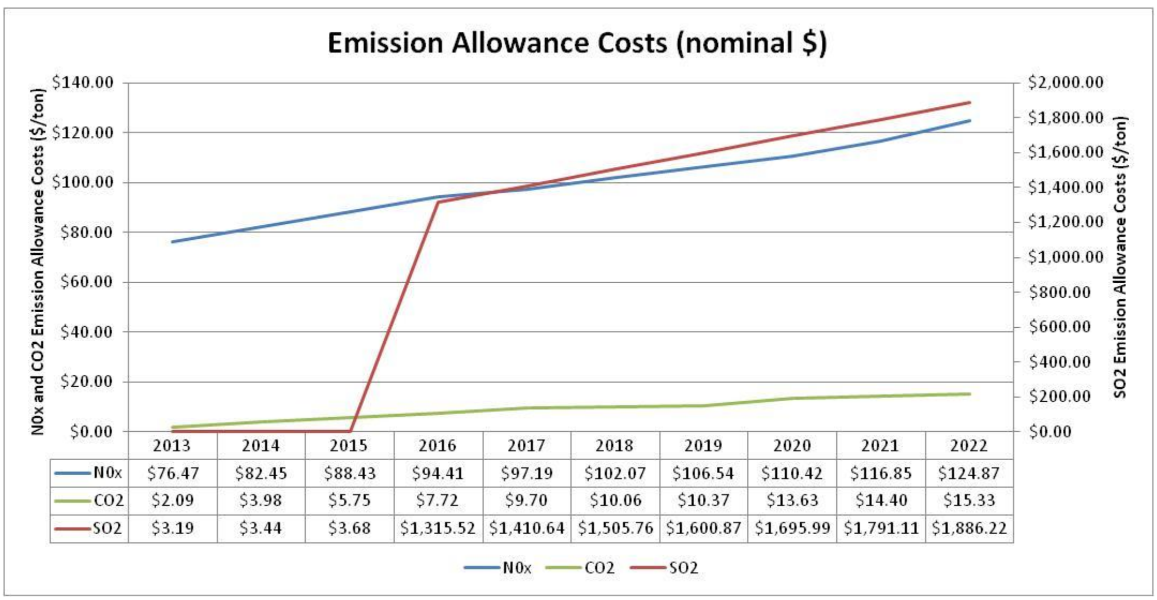
The RGGI program for capping CO_2 emissions from power plants includes six New England states as well as New York, Maryland, and Delaware. Historically the RGGI market has been oversupplied, and prices have remained at the floor. In January 2012 several states, including New York, chose to retire all unsold RGGI allowances from the 2009-2011 compliance period in a effort to reduce the market oversupply. Additionally, RGGI Inc. conducted a mid program review in 2012 which, when effective in 2014, will reduce the emissions cap to roughly the level of CO_2 emitted in 2012. In each subsequent year the cap will be further reduced through various mechanisms.

As part of the mid-program review, RGGI forecast two different price scenarios. The CO_2 allowance price forecast applied to generators in RGGI states in the 2013 CARIS is the average of these two forecasts until 2020. Beyond 2020 the average of the forecasts exceeds the Cost Containment Reserve, which will trigger an increase in the cap to suppress the price. The forecast remains at the cost containment reserve for the final years of the study horizon.

A federal CO_2 program is assumed to take effect in 2020, and to be similar to the RGGI program. The implementation of the federal CO_2 program applies the RGGI allowance price forecast described above to states that are not currently participants in RGGI, as well as the Canadian province of Ontario. It is viewed as unlikely that a national CO_2 program in the United States would be implemented without a similar obligation made by Canada.

Emission costs, which are driven by the fuel type, efficiency and employed emission control technology of each unit, are calculated as the product of emission rate and emission allowance costs. Unit specific incremental emission rates developed from USEPA's Air Markets Program Data (AMPD) were used in the simulations.

Figure 4-5 shows the emission allowance forecast by year in $/Ton.



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
N0x	$76.47	$82.45	$88.43	$94.41	$97.19	$102.07	$106.54	$110.42	$116.85	$124.87
CO2	$2.09	$3.98	$5.75	$7.72	$9.70	$10.06	$10.37	$13.63	$14.40	$15.33
SO2	$3.19	$3.44	$3.68	$1,315.52	$1,410.64	$1,505.76	$1,600.87	$1,695.99	$1,791.11	$1,886.22

Figure 4-5: Emission Allowance Forecast

4.6. Generic Solutions

Generic solutions are evaluated by NYISO for each of the three 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. For the first time in this CARIS, the Tariff requires that DR and EE were modeled as separate solutions to understand the impacts of these resources individually. 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.

4.6.1. Resource Block Sizes

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

- Block size would be reflective of a typical size built for the specific resource type and geographic location;
- Block size is to be small enough to be additive with reasonable step changes; and
- Blocks sizes are in comparable proportions between the resource types.

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

Table 4-4: Transmission Block Sizes

Location	Line System Voltage (kV)	Normal Rating (MVA)[19]
Zone A-G	345	1986

Table 4-5: Generation Block Sizes

Plant Location	Plant Block Size Capacity (MW)
Zone A-K	330[20]

[19] Solution size is based on a double-bundled ACRS 1590 KCmil conductor. The amperage is 3324.
[20] Proposed generic unit is a Siemens SGT6-5000F(5).

Table 4-6: EE and DR Block Sizes

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

4.6.2. 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 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.

- Total resource increase in MWs should be comparable to MW 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
- Total resource increase in MWs should be comparable to MW 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

4.6.3 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 Table 4-7.

Table 4-7: Generic Solution Pricing Considerations

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

Low, mid, and high cost estimates for each element were provided to stakeholders for comment. The transmission costs estimates were reviewed in detail by

National Grid[21], and the estimated cost data for the mid-point of the generation solutions were taken from the 2013 Demand Curve Reset report. The mid-point of the generic cost estimates for Energy Efficiency were derived from the NYSPSC EEPS budget (October 2011) on a zonal basis. Finally, the mid-point of the Demand Response costs were extracted from a study of Advanced Metering costs performed by KEMA. 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 Section 5.4.1. A more detailed discussion of the cost assumptions and calculations is included in Appendix C.

[21] NYPA also reviewed the transmission cost estimates and, while determining that the medium and high cost estimates were similar to the National Grid values, estimated the low transmission cost to include a $3M per mile component.

5. 2013 CARIS Phase 1 Results

This section presents summary level results of the six steps of the 2013 CARIS Phase 1. These six steps include: (1) congestion assessment; (2) ranking of congested elements; (3) selection of three studies; (4) generic solution applications; (5) benefit/cost analysis; and (6) scenario analysis. Study results are described in more detail in Appendix E.

5.1. Congestion Assessment

The CARIS process begins with the development of a ten-year projection of future 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.

5.1.1. 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 quarterly. For more information or source of historical results below see:

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

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

Table 5-1: Historic Demand$ Congestion by Zone 2008-2012 (nominal $M)

Zone	2008	2009	2010	2011	2012
West	(25)	(14)	(1)	(5)	6
Genessee	(9)	4	6	6	3
Central	18	8	11	10	8
North	(2)	(3)	(1)	0	0
Mohawk Valley	10	4	5	5	3
Capital	143	53	62	47	34
Hudson Valley	175	57	73	78	39
Millwood	78	16	23	20	10
Dunwoodie	124	41	49	45	24
NY City	1403	503	560	548	261
Long Island	624	274	350	405	377
NYCA Total	2,612	977	1,141	1,169	765

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

Table 5-2 below lists historic congestion costs, expressed as Demand$, for the top NYCA constraints from 2008 to 2012. The top congested paths are shown below.

Table 5-2: Historic Demand$ Congestion by Constrained Paths 2008-2012 (nominal $M)

Rank	Constrained Path	Historic					Total
		2008	2009	2010	2011	2012	
1	CENTRAL EAST	$ 1,199	$ 435	$ 491	$ 365	$ 255	$ 2,746
2	LEEDS PLEASANT VALLEY	$ 667	$ 149	$ 232	$ 161	$ 137	$ 1,347
3	DUNWOODIE SHORE ROAD	$ 187	$ 118	$ 155	$ 213	$ 255	$ 930
4	GREENWOOD	$ 114	$ 87	$ 132	$ 95	$ 51	$ 480
5	MOTTHAVEN RAINEY	$ 272	$ 50	$ 30	$ 16	$ 5	$ 374
6	NEW SCOTLAND LEEDS	$ 90	$ 44	$ 33	$ 196	$ 9	$ 371
7	MOTTHAVEN DUNWOODIE	$ 33	$ 63	$ 52	$ 87	$ 22	$ 256

* Ranking is based on absolute values.

Table 5-3 summarizes the annual historic congestion results posted by the NYISO. NYISO reports the summaries of the calculated changes in the four historic congestion metrics: 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 Payments.

Table 5-3: Historic NYCA System Changes – Mitigated Bids 2008-2012 (nominal $M)

Year	Change in BPC	Change in Generator Payments	Change in Unhedged Congestion Payments	Change in TCC Payments
2008	243	(417)	1,525	1,143
2009	82	(102)	477	480
2010	94	(116)	640	515
2011	99	(86)	666	511
2012	106	(55)	457	319

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

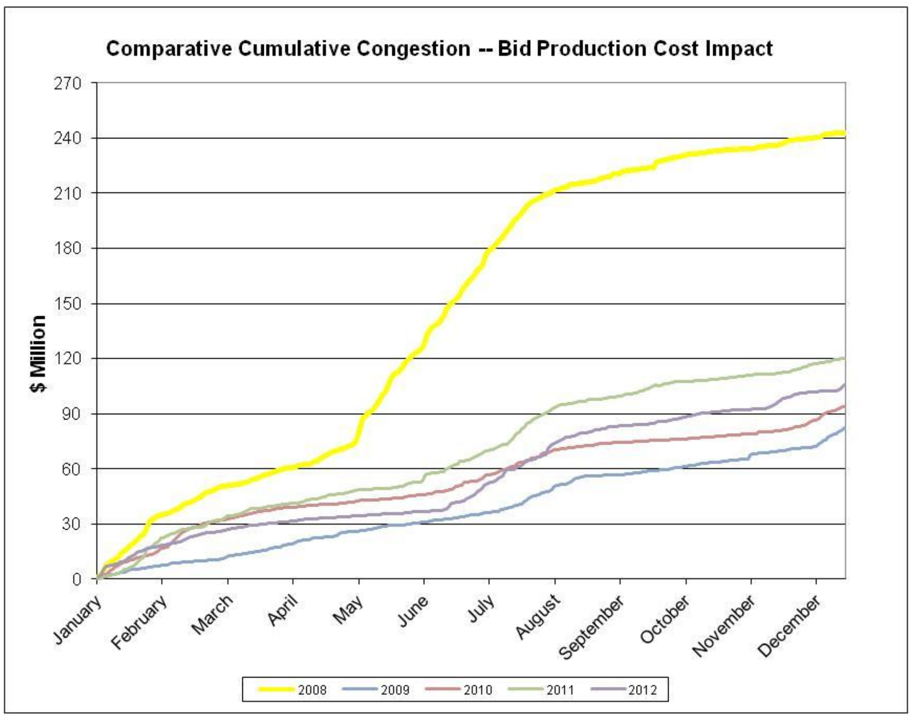


Figure 5-1: Historic Cumulative BPC Savings, 2008-2012 (nominal $M)

5.1.2. 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 Section 3.2, 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.

Discussion

Table 5-4 presents the projected congestion from 2013 through 2022 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 Section 4.1.

Table 5-4: Projection of Future Demand$ Congestion 2013-2022 by Zone (nominal $M)

Demand Congestion (M$)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
West	$ 24	$ 29	$ 42	$ 42	$ 48	$ 47	$ 47	$ 48	$ 56	$ 55
Genessee	$ 3	$ 3	$ 5	$ 5	$ 5	$ 5	$ 6	$ 4	$ 4	$ 4
Central	$ 20	$ 20	$ 24	$ 26	$ 29	$ 32	$ 36	$ 27	$ 35	$ 34
North	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Mohawk Valley	$ 6	$ 6	$ 7	$ 7	$ 8	$ 9	$ 10	$ 8	$ 9	$ 9
Capital	$ 49	$ 53	$ 62	$ 52	$ 66	$ 69	$ 78	$ 57	$ 72	$ 70
Hudson Valley	$ 47	$ 49	$ 54	$ 43	$ 53	$ 53	$ 61	$ 50	$ 60	$ 57
Millwood	$ 15	$ 16	$ 17	$ 14	$ 16	$ 17	$ 19	$ 16	$ 19	$ 18
Dunwoodie	$ 31	$ 32	$ 35	$ 28	$ 34	$ 34	$ 39	$ 32	$ 39	$ 36
NY City	$ 283	$ 295	$ 321	$ 255	$ 310	$ 314	$ 367	$ 304	$ 374	$ 353
Long Island	$ 165	$ 168	$ 182	$ 161	$ 187	$ 204	$ 242	$ 225	$ 261	$ 269
NYCA Total	**$ 643**	**$ 673**	**$ 749**	**$ 634**	**$ 757**	**$ 784**	**$ 906**	**$ 771**	**$ 929**	**$ 907**

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

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

Table 5-5: Projection of Future Demand$ Congestion 2013-2022 by Constrained Path (nominal $M)

Nominal Value ($)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CENTRAL EAST	$ 306	$ 340	$ 396	$ 334	$ 427	$ 445	$ 506	$ 360	$ 465	$ 455
LEEDS PLEASANT VALLEY	$ 150	$ 148	$ 146	$ 103	$ 112	$ 101	$ 123	$ 132	$ 146	$ 109
DUNWOODIE SHORE ROAD	$ 19	$ 18	$ 20	$ 22	$ 23	$ 29	$ 36	$ 40	$ 44	$ 51
GREENWOOD	$ 2	$ 3	$ 4	$ 4	$ 6	$ 8	$ 11	$ 11	$ 14	$ 17
NEW SCOTLAND LEEDS	$ 22	$ 14	$ 10	$ 5	$ 2	$ 1	$ 5	$ 13	$ 8	$ 22
MOTTHAVEN RAINEY	$ 0	$ 0	$ 0	$ 0	$ -	$ -	$ -	$ -	$ -	$ -
MOTTHAVEN DUNWOODIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RAINEY VERNON	$ 0	$ 0	$ 1	$ (0)	$ -	$ -	$ 0	$ (0)	$ 0	$ 0
VOLNEY SCRIBA	$ 22	$ 22	$ 25	$ 31	$ 35	$ 41	$ 46	$ 34	$ 43	$ 41
HUNTLEY PACKARD	$ 13	$ 12	$ 18	$ 20	$ 23	$ 26	$ 24	$ 33	$ 40	$ 42

*The absolute value of congestion is reported.

5.2. Ranking of Congested Elements

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

Table 5-6 lists the ranked elements based on the highest present value of congestion over the fifteen years of the study, including both positive and negative congestion. Central East and Leeds - Pleasant Valley continue to be the paths with the greatest congestion. The top five elements are evaluated in the next step for selection of the three studies.

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

Present Value of Demand Congestion ($M)	Historic	Projected	Total
CENTRAL EAST	$ 3,591	$ 2,923	$ 6,514
LEEDS PLEASANT VALLEY	$ 1,770	$ 955	$ 2,724
DUNWOODIE SHORE ROAD	$ 1,137	$ 208	$ 1,345
GREENWOOD	$ 607	$ 52	$ 659
NEW SCOTLAND LEEDS	$ 462	$ 78	$ 540
MOTTHAVEN RAINEY	$ 516	$ 0	$ 516
MOTTHAVEN DUNWOODIE	$ 318	$ -	$ 318
RAINEY VERNON	$ 260	$ 1	$ 261
VOLNEY SCRIBA	$ 3	$ 241	$ 244
HUNTLEY PACKARD	$ -	$ 172	$ 172

*The absolute value of congestion is reported.

The frequency of actual and projected congestion is shown in Table 5-7 below. The table presents the actual number of congested hours by constraint, from 2008 through 2012, and projected hours of congestion, from 2013 through 2022. The change in the number of projected hours of congestion, by constraint after each generic solution is applied, is shown in Appendix E.

Table 5-7: Number of Congested Hours by Constraint

# of DAM Congested Hours	Actual			CARIS Base Case Projected									
Constraint	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CENTRAL EAST	2,964	2,164	1,467	3,068	3,457	3,615	3,205	3,770	3,795	4,000	2,932	3,168	3,025
MOTTHAVEN DUNWOODIE	1,424	1,550	930	-	-	-	-	-	-	-	-	-	-
DUNWOODIE SHORE ROAD	4,292	6,196	4,130	7,786	7,802	7,746	7,978	7,881	7,984	8,056	8,231	8,216	8,249
GREENWOOD	4,317	5,734	4,440	6,397	6,435	6,489	6,241	6,499	6,554	6,546	7,368	7,383	7,407
HUNTLEY PACKARD	-	-	1	1,241	726	813	851	762	921	979	1,710	1,811	1,735
NEW SCOTLAND LEEDS	156	774	69	392	266	240	104	76	24	63	253	192	437
LEEDS PLEASANT VALLEY	673	503	390	1,913	1,620	1,577	1,055	1,013	845	978	1,343	1,434	948
MOTTHAVEN RAINEY	895	754	415	27	41	59	6	8	-	2	-	1	-
RAINEY VERNON	3,078	3,510	1,556	1,615	1,463	1,579	460	597	735	780	560	690	589
VOLNEY SCRIBA	-	-	333	1,798	1,553	1,634	1,675	1,679	1,864	1,968	1,558	1,812	1,680

5.3. Three CARIS Studies

5.3.1. Selection of the Three Studies

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

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 shown in Figure 5-2.

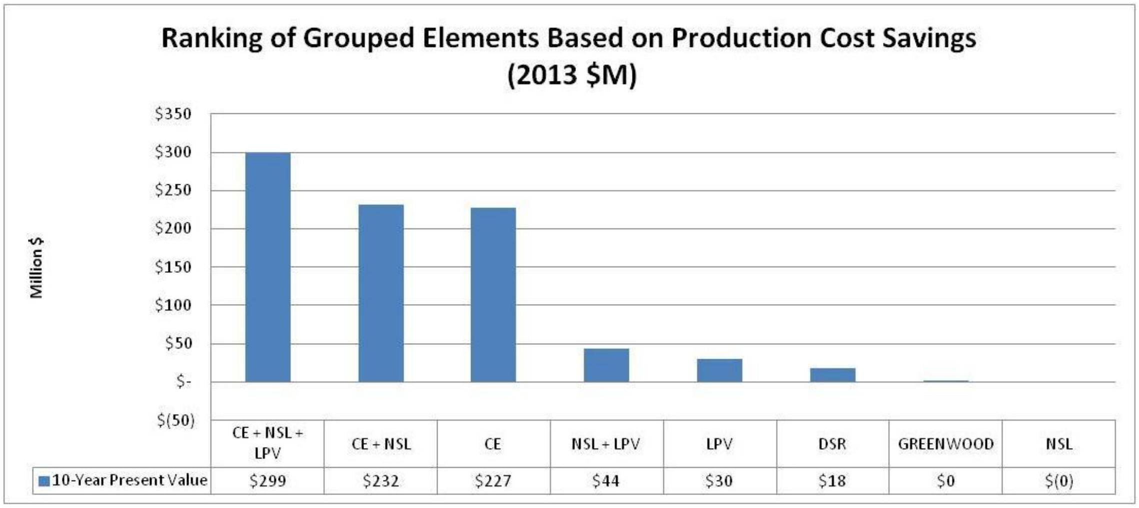


Figure 5-2: Production Costs Savings, 2013-2022 (nominal $M)

The three ranked groupings with the largest change in production cost are selected as the three CARIS studies: Central East-New Scotland-Pleasant Valley (CE-NS-PV), Central East – New Scotland (CE-NS) and Central East (CE). Tables 5-8 and 5-9 present the base case congestion associated with each of the three studies. Although the forecasted level of congestion has changed since the 2011 CARIS, the most congested paths in NYCA remain primarily the same because the Central East through the Leeds – Pleasant Valley corridor are the most operationally limited in the state. A detailed discussion on the ranking process is presented in Appendix E.

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

Study	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Study 1: Central East-New Scotland-Pleasant Valley	479	503	552	443	541	548	633	506	619	586
Study 2: Central East	306	340	396	334	427	445	506	360	465	455
Study 3: New Scotland-Pleasant Valley	172	162	156	109	114	103	127	145	155	131

Table 5-9: Demand$ Congestion of the Top Three CARIS Studies (2013$M)

Study	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
Study 1: Central East-New Scotland-Pleasant Valley	462	452	463	346	394	371	399	298	340	299	3823
Study 2: Central East	296	306	332	261	311	302	319	212	255	232	2825
Study 3: New Scotland-Pleasant Valley	166	146	131	85	83	70	80	86	85	67	998

The location of the top three congested groupings, which define the three studies, along with their present value of congestion (in 2013 dollars) is presented in Figure 5-3.

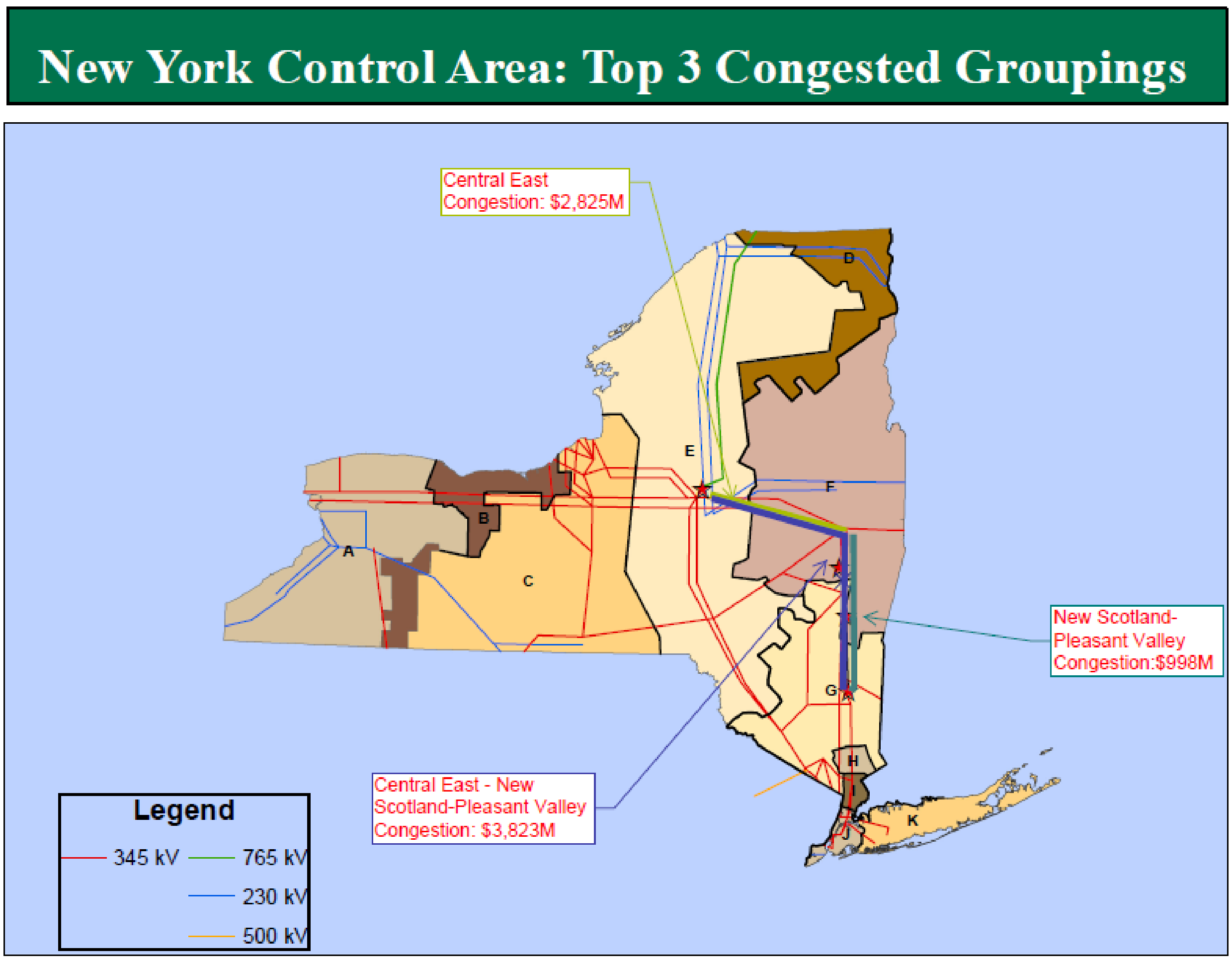


Figure 5-3: Base Case Congestion of Top 3 Congested Groupings, 2013-2022 - Present Value ($M)

5.3.2. Generic Solutions to Congestion

The congestion of each of the three groupings being studied is mitigated by individually applying one of the generic resource types; transmission, generation, 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 C and is consistent with the methodology explained in Section 4 of this report. Resource blocks were applied to relieve a majority of the congestion. Additional resource blocks were not added if diminishing returns would occur.

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

- Other solutions may exist which will alleviate the congestion on the studied elements.
- No attempt has been made to determine the optimum solution for alleviating the congestion.
- No engineering, physical feasibility study, routing study or siting study has been completed for the generic solutions. Therefore, it is unknown if the generic solutions can be physically constructed as 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 7.33% used for the present values analysis is the weighted average of the after-tax Weighted Average Cost of Capital (WACC) for the NYTOs. The weighted average is based on the utilities' annual GWh energy consumption for 2012.

Tables 5-11, 5-14 and 5-17 present the impact of each of the solutions on Demand$ Congestion for each of the studies in 2013$. Transmission has the greatest impact on reducing Demand$ Congestion (44% to 100%) because adding a transmission solution addresses the underlying system constraint that was driving the congestion. The generation solution reduced Demand$ Congestion by 15% to 72%. A large portion of the production cost savings resulting from generation can be attributed to the efficiency advantage of the generic generation solution when compared to the system-wide heat rate. The demand response solution resulted in reducing Demand$ Congestion by 0 to 14%, as expected, since this solution impacted only the top 100 load hours. The energy efficiency solution reduced Demand$ Congestion by 12% to 42%.

Tables 5-12, 5-15 and 5-18 present the impact of each of the solutions on production costs for each of the studies in 2013$. Transmission and generation solutions had roughly commensurate impacts. The impact of the Transmission solution on production costs ranges from $72M - $210M. The generation solution reduced production costs by $57M - $231M. The demand response solution resulted in the least production cost savings ($15M - $23M), again, as expected, since this solution impacted only the top 100 load hours. The energy efficiency solution shows the largest production cost savings (by $1.1B - $2.2B) 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 – New Scotland – Pleasant Valley

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

- Transmission: A new 345 kV line from Edic to New Scotland to Pleasant Valley, 150 Miles. The new line increases the Central East voltage transfer limit by 625 MW and the UPNY-SENY thermal capability by approximately 1200 MW.
- Generation: A new 1,320 MW Plant at Pleasant Valley
- Demand Response : 200 MW Demand Response in Zone F; 200 MW in Zone G; 800 MW in Zone J
- Energy Efficiency : 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 800 MW in Zone J

Table 5-10 shows the Demand$ Congestion of Central East – New Scotland – Pleasant Valley for 2017 and 2022 before and after each of the generic solutions is applied. The base Case congestion numbers, $541M for 2017 and $586M for 2022, are taken directly from Table 5-8 representing the level of congestion of the Study 1 before the solutions.

Table 5-10: Demand$ Congestion Comparison for Central East – New Scotland – Pleasant Valley Study (nominal $M)

CE-NS-PV	2017			2022		
Resource Type	Base Case	Solution	% Change	Base Case	Solution	% Change
Transmission	541	311	-43%	586	349	-41%
Generation - 1,320 MW	541	445	-18%	586	403	-31%
Demand Response - 1,200 MW	541	523	-3%	586	553	-6%
Energy Efficiency - 1,200 MW	541	445	-18%	586	455	-22%

Table 5-11 shows the Demand$ reduction for the 10-year Study Period in 2013 dollars from 2013 to 2022 for the Central East – New Scotland – Pleasant Valley study after generic solutions were applied.

Table 5-11: Demand$ Congestion Comparison for Central East – New Scotland – Pleasant Valley Study (Present Value in 2013 $M)

Resource Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total	% Change
Transmission	(223)	(222)	(224)	(149)	(167)	(154)	(165)	(127)	(144)	(121)	(1,698)	-44%
Generation - 1,320 MW	(114)	(91)	(88)	(56)	(70)	(48)	(58)	(77)	(98)	(94)	(794)	-21%
Demand Response - 1,200 MW	(10)	(1)	(1)	(3)	(13)	(3)	(15)	(8)	(16)	(17)	(88)	-2%
Energy Efficiency - 1,200 MW	(78)	(80)	(83)	(50)	(70)	(59)	(79)	(61)	(67)	(67)	(693)	-18%

Table 5-12 shows the production cost savings expressed as the present value in 2013 dollars from 2013 to 2022 for the Central East – New Scotland – Pleasant Valley study after generic solutions were applied.

Table 5-12: Central East – New Scotland – Pleasant Valley Study: NYCA-wide Production Cost Savings (Present Value in 2013 $M)

Resource Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
Transmission	(31)	(24)	(22)	(19)	(20)	(20)	(22)	(17)	(19)	(17)	(210)
Generation - 1,320 MW	(24)	(21)	(18)	(20)	(16)	(13)	(17)	(31)	(33)	(38)	(231)
Demand Response - 1,200 MW	(4)	(6)	(4)	(2)	(2)	(2)	(1)	(1)	(1)	(2)	(23)
Energy Efficiency - 1,200 MW	(242)	(228)	(219)	(230)	(225)	(222)	(216)	(221)	(215)	(214)	(2,232)

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 transmission lines by 43% in 2017 and 41% in 2022 respectively, as shown in Table 5-10. As presented in Table 5-12, total ten year NYCA-wide production cost savings is $210 million (present value) as the result of better utilization of economic generation in the state and economic imports from neighboring regions made available by the large scale transmission upgrades represented by this generic transmission solution.

The generation solution is projected to reduce congestion by 18% in 2017 and 31% in 2022. The ten-year production cost savings of $231 million (present value) are due to the uncongested location 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 G and J Demand Response solution is projected to reduce congestion by 3% in 2017 and 6% in 2022, while the ten-year total production cost saving is $23 million (present value). 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 G and J Energy Efficiency solution is projected to reduce congestion by 18% in 2017 and 22% in 2022, while the ten-year total production cost saving is $2,232 million (present value). The relative 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

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 reduces the UPNY-SENY transfer capability by approximately 100 MW and increases the Central East voltage limit by 550 MW.
- Generation: A new 660 MW Plant at New Scotland
- Demand Response : 200 MW Demand Response in Zone F; 200 MW in Zone G; 200 MW in Zone J
- Energy Efficiency : 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 200 MW in Zone J

Table 5-13 shows the Demand$ Congestion of Central East for 2017 and 2022 before and after each of the generic solutions is applied.

Table 5-13: Demand$ Congestion Comparison for Central East Study (nominal $M)

CE	2017			2022		
Resource Type	Base Case	Solution	% Change	Base Case	Solution	% Change
Transmission	427	249	-42%	455	253	-44%
Generation - 660 MW	427	387	-9%	455	311	-32%
Demand Response - 600 MW	427	434	2%	455	442	-3%
Energy Efficiency - 600 MW	427	379	-11%	455	379	-17%

Table 5-14 shows the Demand$ reduction for the 10-year Study Period in 2013 dollars from 2013 to 2022 for the Central East study after generic solutions were applied.

Table 5-14: Demand$ Congestion Comparison for Central East Study (Present Value in 2013 $M)

Resource Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total	% Change
Transmission	(115)	(129)	(140)	(103)	(130)	(145)	(142)	(101)	(125)	(103)	(1,233)	-44%
Generation - 660 MW	(32)	(24)	(33)	(28)	(29)	(38)	(38)	(50)	(73)	(73)	(419)	-15%
Demand Response - 600 MW	5	(2)	3	4	5	(1)	(7)	0	(0)	(6)	0	0%
Energy Efficiency - 600 MW	(34)	(38)	(35)	(21)	(35)	(30)	(36)	(23)	(39)	(39)	(330)	-12%

Table 5-15 shows the NYCA-wide production cost savings expressed as the present value in 2013 dollars from 2013 to 2022 for the Central East study after generic solutions were applied.

Table 5-15: Central East Study: NYCA-wide Production Cost Savings (Present Value in 2013 $M)

Resource Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
Transmission	(13)	(11)	(11)	(12)	(12)	(16)	(14)	(7)	(11)	(9)	(116)
Generation - 660 MW	(3)	(4)	(2)	(5)	(3)	(3)	(4)	(10)	(10)	(13)	(57)
Demand Response - 600 MW	(3)	(1)	(3)	(2)	(1)	(1)	(3)	(2)	(2)	(2)	(20)
Energy Efficiency - 600 MW	(121)	(114)	(108)	(115)	(112)	(112)	(108)	(109)	(108)	(107)	(1,114)

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 42% in 2017 and 44% in 2022. The total ten-year production cost savings of $116 million (present value) are again due to increased use of lower cost generation in upstate and increased levels of imports compared to the base case.

The generation solution is projected to reduce congestion by 9% in 2017 and 32% in 2022. The ten-year production cost savings of $57 million (present value) are derived from the heat rate efficiency advantage of the new generic unit compared to the average system heat rate. Imports are significantly reduced in this solution. 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 increase congestion by 2% in 2017 and reduce congestion by 3% in 2022, while the ten-year total production cost saving is $20 million (present value). 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 11% in 2017 and 17% in 2022, while the ten-year total production cost saving is $1,114 million (present value). The relative large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. EE solutions show greater reductions in production cost than the generation, transmission and energy efficiency solutions.

Study 3: New Scotland – Pleasant Valley

The following generic solutions were applied for the New Scotland-Pleasant Valley study, and the results are shown in Table 5-13:

- Transmission: A new 345 kV line from New Scotland to Pleasant Valley; 65 Miles. The new line increases the UPNY-SENY thermal capability by approximately 1200 MW and Central East voltage limit by 75 MW.
- Generation: Install a new 1,320 MW Plant at Pleasant Valley.
- Demand Response: 200 MW in Zone G; 1000 MW in Zone J
- Energy Efficiency: 200 MW in Zone G; 1000 MW in Zone J

Table 5-16 shows the Demand$ Congestion of New Scotland-Pleasant Valley for 2017 and 2022 before and after each of the generic solutions is applied. Transmission has the greatest impact in reducing congestion and eliminated the entire congestion for the New Scotland-Pleasant Valley path.

Table 5-16: Demand$ Congestion Comparison for New Scotland-Pleasant Valley (nominal $M)

NS-PV	2017			2022		
Resource Type	Base Case	Solution	% Change	Base Case	Solution	% Change
Transmission	114	(0)	-100%	131	0	-100%
Generation - 1,320 MW	114	32	-72%	131	12	-91%
Demand Response - 1.200 MW	114	96	-15%	131	101	-23%
Energy Efficiency - 1,200 MW	114	63	-45%	131	63	-52%

Table 5-17 shows the Demand$ reduction for the 10-year Study Period in 2013 dollars from 2013 to 2022 for the New Scotland – Pleasant Valley study after generic solutions were applied.

Table 5-17: Demand$ Congestion Comparison for New Scotland-Pleasant Valley (2013$M)

Resource Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total	% Change
Transmission	(166)	(146)	(131)	(85)	(83)	(70)	(80)	(86)	(85)	(67)	(998)	-100%
Generation - 1,320 MW	(111)	(90)	(88)	(60)	(60)	(50)	(58)	(70)	(70)	(61)	(718)	-72%
Demand Response - 1,200 MW	(8)	(11)	(11)	(14)	(13)	(13)	(20)	(14)	(16)	(15)	(135)	-14%
Energy Efficiency - 1,200 MW	(47)	(47)	(53)	(37)	(37)	(33)	(42)	(44)	(40)	(35)	(415)	-42%

Table 5-18 shows the NYCA-wide production cost savings expressed as the present value in 2013 dollars from 2013 to 2022 for the New Scotland-Pleasant Valley study after the generic solutions were applied.

Table 5-18: New Scotland-Pleasant Valley Study: NYCA-wide Production Cost Savings (Present Value in 2013$M)

Resource Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
Transmission	(15)	(9)	(10)	(6)	(5)	(5)	(6)	(6)	(5)	(5)	(72)
Generation - 1,320 MW	(24)	(21)	(18)	(20)	(16)	(13)	(17)	(31)	(33)	(38)	(231)
Demand Response - 1,200 MW	(4)	(4)	(3)	(2)	(1)	(1)	(1)	0	0	(0)	(15)
Energy Efficiency - 1,200 MW	(241)	(228)	(218)	(228)	(223)	(219)	(213)	(218)	(214)	(212)	(2,214)

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

The addition of the New Scotland to Pleasant Valley 345 kV transmission line results in a projected total ten-year production cost savings of $72 million (present value). Elimination of the New Scotland-Pleasant Valley congestion allows the downstate load better access to upstate generation and economic imports from neighbors. It is also noted that relieving the congestion on the New Scotland- Pleasant Valley lines increases the congestion on the other two study groups.

The generation solution is projected to reduce congestion across NYCA for the planning horizon. The ten-year production cost savings of $231 million (present value) are due to the uncongested location and the assumed better heat rate of the generic generating unit compared to the average system heat rate. 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 G and J Demand Response solution is projected to reduce congestion by 15% in 2017 and 23% in 2022, while the ten-year total production cost saving is $15 million (present value). 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 G and J Energy Efficiency solution is projected to reduce congestion by 45% in 2017 and 52% in 2022, while the ten-year total production cost saving is $2,214 million (present value). The relative large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. EE solutions show greater reductions in production cost than the generation and transmission solutions.

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

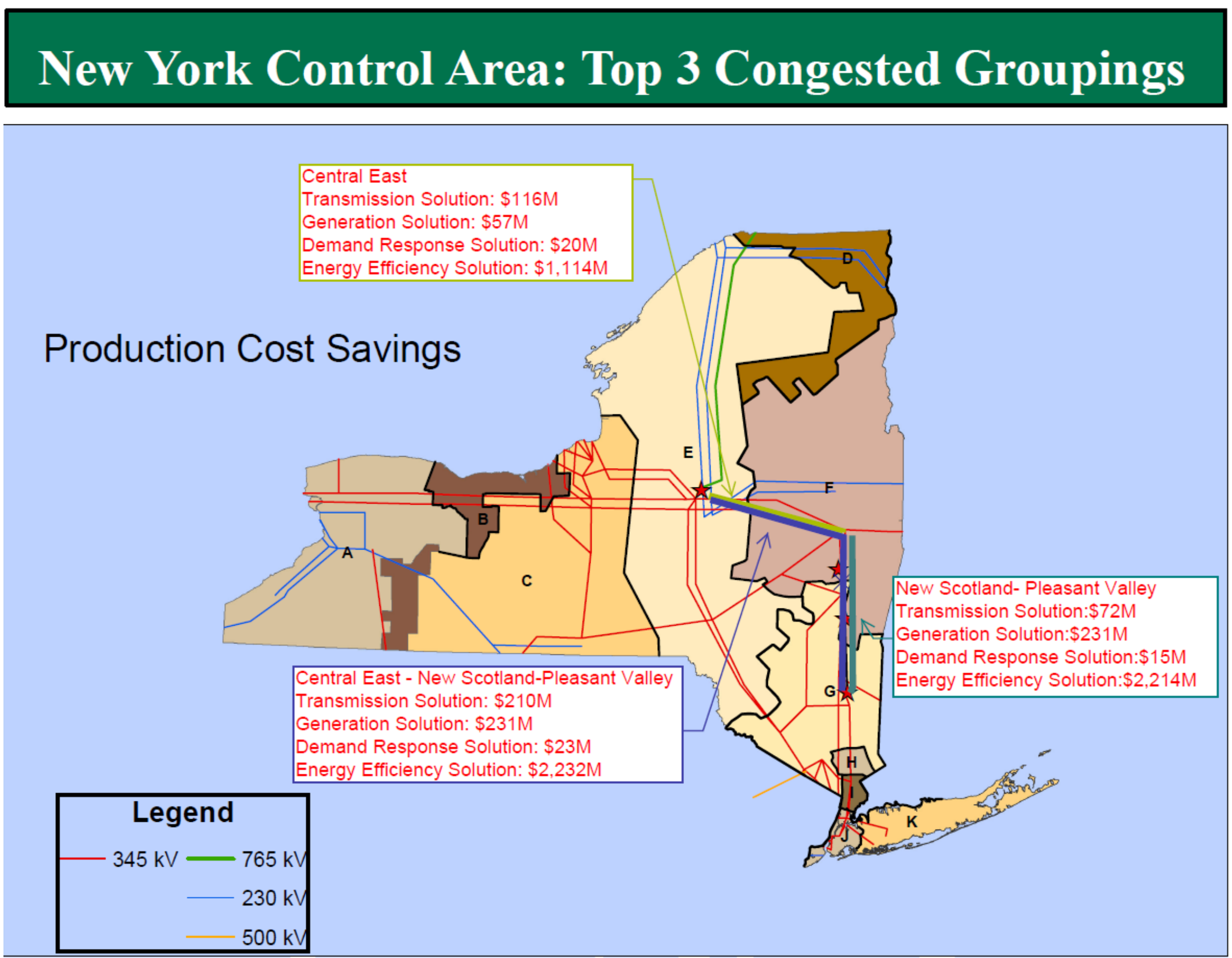


Figure 5-4: Total NYCA-wide Production Cost Savings 2013-2022 (Present Value in 2013 $M)

5.4. Benefit/Cost Analysis

The NYISO conducted the benefit/cost analysis for each of the three: Central East – New Scotland – Pleasant Valley, Central East, and New Scotland – Pleasant Valley. The CARIS benefit/cost analysis assumes a levelized generic carrying charge rate of 16% for transmission and generation solutions. Therefore, for a given generic solution pertaining to a constrained element, the carrying charge rate, in conjunction with an appropriate discount rate (see description in Section 5.3.2 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 16% carrying charge rate used in these CARIS benefit/cost calculations reflects generic figures for a return on investment, federal and state income taxes, property taxes, insurance, fixed O&M, and depreciation (assuming a straight-line 30-year method). The calculation of the appropriate capital recovery factor, and, hence, the B/C ratio, is based on the first ten years of the 30-year period,[22] using a discount rate of 7.33% , and the 16% carrying charge rate, yielding a capital recovery factor equal to 1.147.

For the energy efficiency solution, the overnight costs in the benefit to cost calculation include only utility program costs or subsidies and do not include costs incurred by the utility customer. The costs used are, therefore, below the total cost to implement the energy efficiency measures; and the B/C ratio is higher than it would be, should the customer-side costs be included.

For the demand response solution, the overnight costs do not reflect energy payments to demand-response providers participating in NYISO EDRP and SCR programs associated with the peak load reductions. For the six events in the summer 2012 during which demand resources were called upon, these costs averaged approximately $11,000 / MW. [23] Similarly, projected capacity payments for these resources are not incorporated as costs.

5.4.1. Cost Analysis

Table 5-19 includes the total cost estimate for each generic solution based on the unit pricing included in Appendix C. The detailed cost breakdown for each solution is included in Appendix E. These are simplified estimates of overnight installation costs and do not include any of the many complicating factors that could be faced by

[22] The carrying charge rate of 16% was based on a 30-year period because the Tariff provisions governing Phase 2 of CARIS refer to calculating costs over 30 years for information purposes. See OATT Attachment Y, Section 31.5.3.3.4.
[23] See Table 8, page 17, of the NYISO's 2012 Annual Report on Demand Response Programs (http://www.nyiso.com/public/webdocs/markets_operations/documents/Legal_and_Regulatory/FERC_Filings/2013/Jan/NYISO_DR_Report_01-15-13_final.pdf)

individual projects. On-going fixed operation and maintenance costs and other fixed costs of operating the facility are captured in the capital recovery factor.

Table 5-19: Generic Solution Overnight Costs for Each Study[24]

Generic Solution Cost Summary ($M)			
Studies	Study 1: Central East-New Scotland-Pleasant Valley	Study 2: Central East	Study 3: New Scotland - Pleasant Valley
Transmission			
Substation Terminals	Edic to New Scotland to Pleasant Valley	Edic to New Scotland	New Scotland to Pleasant Valley
Miles (# of terminals)	150 (3)	85 (2)	65(2)
High	1,131	648	502
Mid	774	443	343
Low	312	179	139
Generation			
Substation Terminal	Pleasant Valley	New Scotland	Pleasant Valley
# of 330 Blocks	4	2	4
High	2,316	1,046	2,316
Mid	1,889	853	1,889
Low	1,463	661	1,463
DR			
Zone	F , G and J	F ,G and J	G and J
# of 200 MW Blocks	6	3	6
High	394	197	394
Mid	278	139	278
Low	199	100	199
EE			
Zone	F , G and J	F , G and J	G and J
# of 200 MW Blocks	6	3	6
High	3,920	1,520	4,420
Mid	3,140	1,220	3,540
Low	2,360	920	2,660

5.4.2. Primary Metric Results

The primary benefit metric for the three CARIS studies is the reduction in NYCA-wide production costs. Table 5-20 shows the production cost savings used to calculate the benefit/cost ratios for the generic solutions. In each of the three studies the Energy Efficiency solution produced the highest production cost savings because it directly reduces the energy production requirements. In the Central East to New Scotland to Pleasant Valley and New Scotland to Pleasant Valley studies, the generation solutions produced higher production cost savings than transmission. Conversely, in the Central East study the generation solution produced a higher production cost savings than the transmission solution. In all cases the Demand Response solution had the least impact on production cost savings.

[24] Appendix C contains a detailed description of the derivation of the generic solution costs.

Table 5-20: Production Cost Generic Solutions Savings 2013-2022: Present Value in 2013 ($M)

Study	Ten-Year Production Cost Savings			
	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Study 1: Central East -New Scotland-Pleasant Valley	210	231	23	2,232
Study 2: Central East	116	57	20	1,114
Study 3: New Scotland-Pleasant Valley	72	231	15	2,214

5.4.3. Benefit/Cost Ratios

Figure 5-5 shows the benefit/cost ratios for each study and each generic solution.

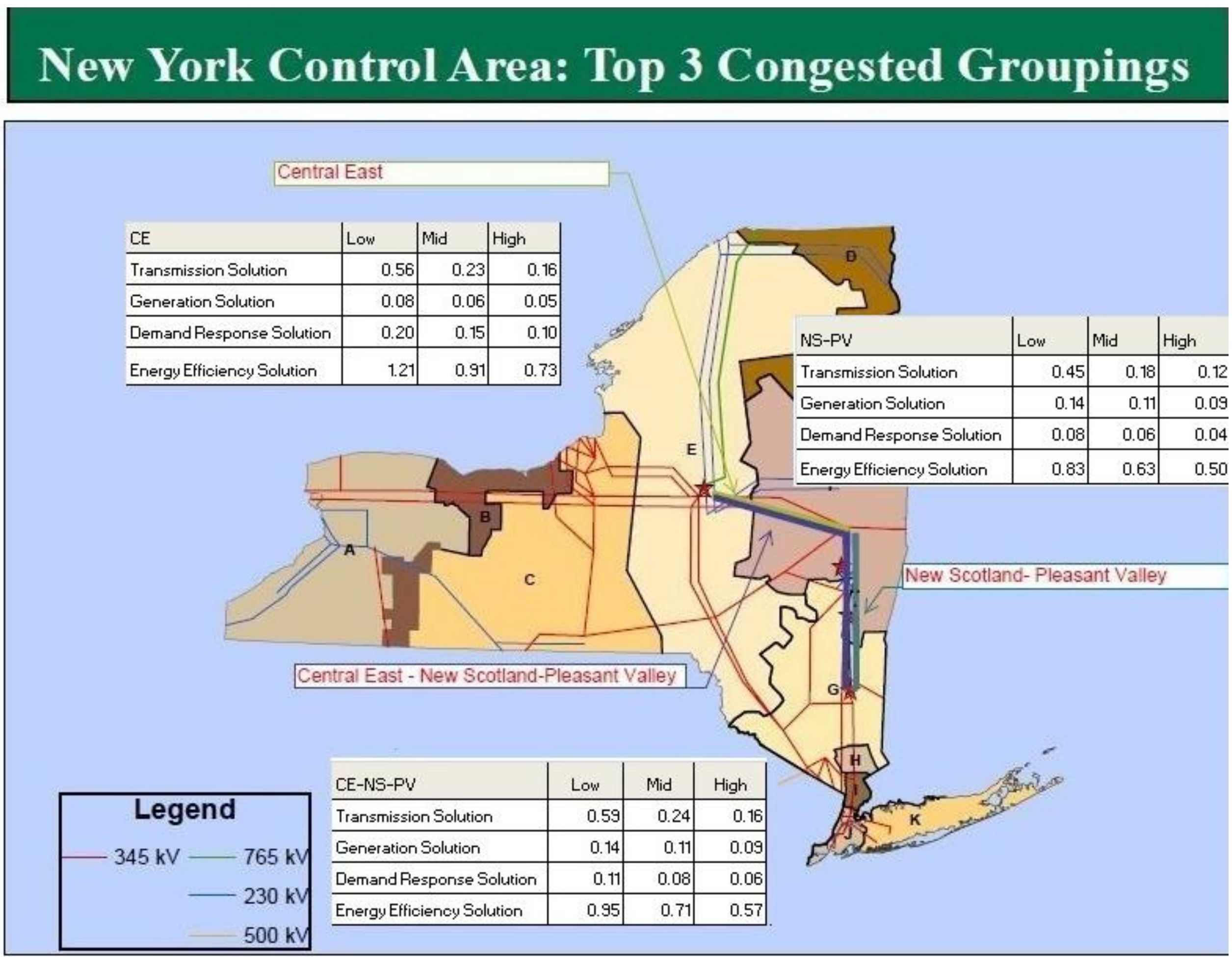


Figure 5-5: B/C Ratio (High, Mid, and Low Cost Estimate Ranges)

5.4.4. Additional Metrics Results

Additional metrics, which are provided for information purposes in Phase 1, are presented in Table 5-21, Table 5-22, Table 5-23 and Table 5-24 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. Details on the calculations are in Appendix E.

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.[25] 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.

Table 5-21: Ten-Year Change in Load Payments, Generator Payments, TCC Payments and Losses Costs (Present Value $M)[26]

	LOAD PAYMENT	NYCA LOAD PAYMENT	EXPORT PAYMENT	GENERATOR PAYMENT	NYCA GENERATOR PAYMENT	IMPORT PAYMENT	TCC PAYMENT	LOSSES COSTS
TRANSMISSION SOLUTIONS								
Edic-New Scotland-Pleasant Valley	$194	$67	$127	$1,382	$1,281	$101	($1,430)	($316)
Edic-New Scotland	$193	$13	$180	$687	$541	$146	($654)	($166)
New Scotland-Pleasant Valley	($61)	($2)	($58)	$309	$300	$9	($413)	($139)
GENERATION SOLUTIONS								
Pleasant Valley	($272)	($1,022)	$750	$6	$408	($402)	($217)	($14)
New Scotland	($83)	($408)	$324	($369)	($215)	($153)	$282	$41
Pleasant Valley	($272)	($1,022)	$750	$6	$408	($402)	($217)	($14)
DEMAND RESPONSE SOLUTIONS								
F (200), G(200), J(800)	($96)	($126)	$29	($100)	($74)	($26)	($2)	$5
F (200), G(200), J(200)	($47)	($60)	$13	($40)	($31)	($9)	($10)	($2)
G(200), J(1,000)	($70)	($103)	$33	($86)	($60)	($27)	$9	$3
ENERGY EFFICIENCY SOLUTIONS								
F (200), G(200), J(800)	($2,368)	($2,941)	$573	($2,173)	($1,827)	($346)	($129)	($209)
F (200), G(200), J(200)	($1,208)	($1,495)	$287	($1,179)	($997)	($182)	($32)	($58)
G(200), J(1,000)	($2,549)	($3,077)	$528	($2,253)	($1,906)	($347)	($216)	($214)

Note: A negative number implies a reduction in payments

25

http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/Announcements/Info_and_Announcements/Summer_2013_Documents/Demand_Curve_Summer_2013_FINAL.pdf.

26 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.

Table 5-22: ICAP MW Impact

CARIS Solutions		MW Impact (MW)		
		NYCA	NYC	LI
Study #1 Central East-New Scotland-Pleasant Valley	Transmission	770	208	107
	Generation	1,580	415	214
	Energy Efficiency	1,600	433	223
	Demand Response	1,560	422	218
Study #2 Central East	Transmission	(315)	(85)	(44)
	Generation	0	0	0
	Energy Efficiency	730	198	102
	Demand Response	700	189	98
Study #3 New Scotland-Pleasant Valley	Transmission	760	306	106
	Generation	1580	415	214
	Energy Efficiency	1710	463	239
	Demand Response	1680	455	234

Table 5-23: ICAP $Impact

		ICAP Variant 1	ICAP Variant 2
	Transmission		
Study 1: CE-NS-PV	Edic-New Scotland-Pleasant Valley	($739)	($4,221)
Study 2: CE	Edic-New Scotland	$302	$1,739
Study 3: NS-PV	New Scotland-Pleasant Valley	($730)	($4,171)
	Generation		
Study 1: CE-NS-PV	Pleasant Valley	($1,501)	($8,406)
Study 2: CE	New Scotland	$0	$0
Study 3: NS-PV	Pleasant Valley	($1,501)	($8,406)
	Demand Response		
Study 1: CE-NS-PV	F (200), G (200), J (800)	($1,498)	($8,368)
Study 2: CE	F (200), G (200) , J (200)	($672)	($3,841)
Study 3: NS-PV	G (200) , J (1000)	($1,613)	($8,980)
	Energy Efficiency		
Study 1: CE-NS-PV	F (200), G (200), J (800)	($1,536)	($8,572)
Study 2: CE	F (200), G (200) , J (200)	($701)	($4,008)
Study 3: NS-PV	G (200) , J (1000)	($1,642)	($9,135)

The ten-year changes in total emissions resulting from the application of generic solutions are reported in Table 5-24 below. The base case ten-year emission totals for NYCA are: CO_2 = 335,319 thousand- tons, SO_2= 121,164 tons and NOx = 208,730 tons. The study results reveal that all of the generic solutions impact emissions by less than 10%. For SO_2 and NOx, the energy efficiency and generation solutions have comparable impacts, reducing emissions in the range of 1.1% to 5.3%. For CO_2, energy efficiency reduces emissions 2.4% to 4.9% while the generation solutions increase emissions by up to 2.8%. While the transmission solution and demand response had generally less impact on the emission levels, the transmission solutions did result in an increase in the SO_2 emissions due to the higher utilization of coal units in western New York.

The current Installed Capacity in NYCA as reported in the 2013 Gold Book is 37,920 MW. The generic generation solutions of 1,320 and 660 MWs represent the equivalent of a 3.4 % and 1.7% increase, respectively, in Installed Capacity. The generic demand response solutions of 1,200 MW and 600 MW of DR and EE could be considered as additional resources which would be equivalent to 3.2% and 1.6%, respectively, of Installed Capacity. The capability of the generic transmission solution is 1,986 MVA, which would be utilized to shift dispatch patterns of several hundred MW of capacity, or something on the order of 1% of Installed Capacity. The three generic solutions can be considered to change the fleet emission characteristics on the order of

1-5%. The comparison of the relative emission changes among solution types and across locations provides insight about the relative air related impacts if the emissions assumptions come to fruition. The emissions results include only emissions from NYCA units. The external emissions impacts associated with changes in NYCA imports are not reported.

Table 5-24: Ten-Year Change in NYCA CO_2, SO_2 and NOx Emissions (Dollars in Present Value)

		SO2			CO2			NOx		
Study	Generic Solutions	Tons	% Change	Cost ($M)	1000 Tons	% Change	Cost ($M)	Tons	% Change	Cost ($M)
	Transmission									
Study 1: CE-NS-PV	Edic-New Scotland-Pleasant Valley	8,620	7.1%	$5.5	280	0.1%	$6.4	1,878	0.9%	$0.2
Study 2: CE	Edic-New Scotland	5,245	4.3%	$3.6	734	0.2%	$5.3	2,211	1.1%	$0.1
Study 3: NS-PV	New Scotland-Pleasant Valley	1,420	1.2%	$1.1	-1,389	-0.4%	-$5.3	-1,156	-0.6%	$0.0
	Generation									
Study 1: CE-NS-PV	Pleasant Valley	-6,445	-5.3%	-$3.6	9,463	2.8%	$68.4	-6,558	-3.1%	-$0.4
Study 2: CE	New Scotland	-3,895	-3.2%	-$2.2	4,223	1.3%	$27.9	-2,198	-1.1%	-$0.2
Study 3: NS-PV	Pleasant Valley	-6,445	-5.3%	-$3.6	9,463	2.8%	$68.4	-6,558	-3.1%	-$0.4
	Demand Response									
Study 1: CE-NS-PV	F (200), G (200), J (800)	-866	-0.7%	-$0.5	237	0.1%	$1.3	-224	-0.1%	$0.0
Study 2: CE	F (200), G (200), J (200)	-579	-0.5%	-$0.4	-84	0.0%	-$0.6	-237	-0.1%	$0.0
Study 3: NS-PV	G (200), J (1000)	-608	-0.5%	-$0.4	429	0.1%	$2.6	-142	-0.1%	$0.0
	Energy Efficiency									
Study 1: CE-NS-PV	F (200), G (200), J (800)	-5,514	-4.6%	-$3.4	-16,030	-4.8%	-$87.7	-6,437	-3.1%	-$0.4
Study 2: CE	F (200), G (200), J (200)	-2,966	-2.4%	-$1.6	-7,897	-2.4%	-$43.6	-3,237	-1.6%	-$0.2
Study 3: NS-PV	G (200), J (1000)	-5,757	-4.8%	-$4.0	-16,342	-4.9%	-$88.8	-7,078	-3.4%	-$0.4

5.5. Scenario Analysis

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

A forecast of congestion is impacted by many variables for which the future values are uncertain. Scenario analyses are methods of identifying the relative impact of pertinent variables on the 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 the full amount of the resources added through the State Renewable Portfolio Standard (RPS) combined with the full achievement of the State Energy Efficiency Portfolio Standard (EEPS), fuel price and load forecast uncertainties, costs of emissions, and removing the Athens SPS from service. The objective of the scenario analysis is to determine the change in the costs of congestion that is caused by variables that differ from their base case values. The simulations were conducted for the entire 10-year Study Period.

5.5.1. Scenario Analysis

Table 5-25 summarizes the scenarios studied in CARIS Phase 1. The scenarios consider the effects of changes to the base case model. These changes are described as “Variables” in the table below.

Table 5-25: Scenario Matrix

Scenario	Variables
Implementation of Cross-State Air Pollution Rule (CSAPR)	Increases in NO_x and SO_2 costs as projected by EPA
Higher Load Forecast	4% higher (referred to as the Econometric Forecast in Tables I-3a and I-3b, *2013 Load and Capacity Data*)
Lower Load Forecast	5% lower (reflects full EEPS Goals achievement)
Full Main Tier RPS and Full EEPS Goals Achievement	Add renewables from Interconnection queue and reduce 2015 coincident peak load to 32147 MW
Athens SPS Out of Service	2013-2022
Higher Natural Gas Prices	One standard deviation
Lower Natural Gas Prices	One standard deviation
Lower CO_2 Emission costs	$5/ton Ceiling
Higher Natural Gas costs in Midstate	Midstate & New England/ Upstate differential doubled
No National CO_2 Program	CO_2 Allowance Costs for non-RGGI states set to $0

Table 5-26 presents the impact of ten scenarios selected for study. Those impacts are expressed as the change in congestion costs between the base case and the scenario case.

Table 5-26: Comparison of Base Case and Scenario Cases, 2017 and 2022 (nominal $M)

	2017 Scenarios: (Change in Demand$ Congestion from Base Case) (Nominal $M)									
Constraints	CSAPR	Higher Load Forecast	Lower Load Forecast	Full RPS/EEPS Achievement	Athens SPS Out of Service	Higher Natural Gas Prices	Lower Natural Gas prices	Capped Carbon Prices	Higher Natural Gas Costs in Midstate	No National CO2 Program
CENTRAL EAST	(12)	(15)	48	390	(17)	181	(180)	19	402	0
LEEDS PLEASANT VALLEY	3	17	(28)	(20)	48	15	(21)	11	(26)	0
DUNWOODIE SHORE ROAD	1	14	(3)	0	(1)	5	(3)	(1)	0	0
GREENWOOD	(0)	5	(4)	(4)	0	1	(1)	(1)	(2)	0
NEW SCOTLAND LEEDS	1	1	0	2	(1)	1	5	1	(2)	0
MOTTHAVEN RAINEY	0	0	0	0	0	0	0	0	0	0
MOTTHAVEN DUNWOODIE	0	0	0	0	0	0	0	0	0	0
RAINEY VERNON	0	0	0	0	(0)	0	(0)	(0)	(0)	0
VOLNEY SCRIBA	3	3	(4)	(9)	1	5	(7)	(0)	(10)	0
HUNTLEY PACKARD	5	1	1	1	1	(1)	7	3	(1)	0
Central East – New Scotland – Pleasant Valley	(7)	3	20	372	31	198	(195)	31	374	0
Central East	(12)	(15)	48	390	(17)	181	(180)	19	402	0
New Scotland-Pleasant Valley	4	18	(28)	(19)	48	16	(15)	12	(28)	0

	2022 Scenarios: (Change in Demand$ Congestion from Base Case) (Nominal $M)									
Constraints	CSAPR	Higher Load Forecast	Lower Load Forecast	Full RPS/EEPS Achievement	Athens SPS Out of Service	Higher Natural Gas Prices	Lower Natural Gas prices	Capped Carbon Prices	Higher Natural Gas Costs in Midstate	No National CO2 Program
CENTRAL EAST	(1)	11	19	238	(42)	46	(196)	81	355	222
LEEDS PLEASANT VALLEY	(8)	22	(39)	(25)	84	12	(30)	13	(22)	(8)
DUNWOODIE SHORE ROAD	(1)	67	(13)	(10)	(2)	6	(11)	(1)	0	4
GREENWOOD	(1)	8	(12)	(12)	1	5	(5)	2	(5)	5
NEW SCOTLAND LEEDS	0	(2)	(2)	(2)	(7)	(5)	2	(4)	(17)	(16)
MOTTHAVEN RAINEY	0	0	0	0	0	0	0	0	0	0
MOTTHAVEN DUNWOODIE	0	0	0	0	0	0	0	0	0	0
RAINEY VERNON	(0)	0	(0)	(0)	0	0	(0)	0	(0)	0
VOLNEY SCRIBA	(0)	(0)	(3)	(9)	1	4	(16)	(4)	(7)	6
HUNTLEY PACKARD	0	(3)	(3)	(9)	1	(16)	9	(17)	(6)	(13)
Central East – New Scotland – Pleasant Valley	(9)	32	(22)	211	35	52	(224)	90	315	198
Central East	(1)	11	19	238	(42)	46	(196)	81	355	222
New Scotland-Pleasant Valley	(8)	20	(41)	(27)	77	6	(28)	9	(39)	(24)

Table 5-27 below presents a summary of how each of the three transmission groupings chosen for study is affected by each of the scenarios for the entire Study Period.

Table 5-27: Impact on Demand$ Congestion (2013$M)

Constraints	Scenarios: (Aggregate Change in Demand$ Congestion from Base Case) ($2013M)									
	CSAPR	Higher Load Forecast	Lower Load Forecast	Full RPS/EEPS Achievement	Athens SPS Out of Service	Higher Natural Gas Prices	Lower Natural Gas prices	Capped Carbon Prices	Higher Natural Gas Cost Differential	No National CO2 Program
Central East – New Scotland – Pleasant Valley	(232)	45	(66)	1,424	255	1,084	(1,487)	165	2,189	268
Central East	(218)	(113)	150	1,563	(153)	949	(1,354)	120	2,432	304
New Scotland-Pleasant Valley	(14)	158	(217)	(139)	408	135	(133)	46	(243)	(36)

Figures 5-6 through 5-8 show the congestion impact results of ten scenarios performed for the ten-year Study Period. While the table 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.

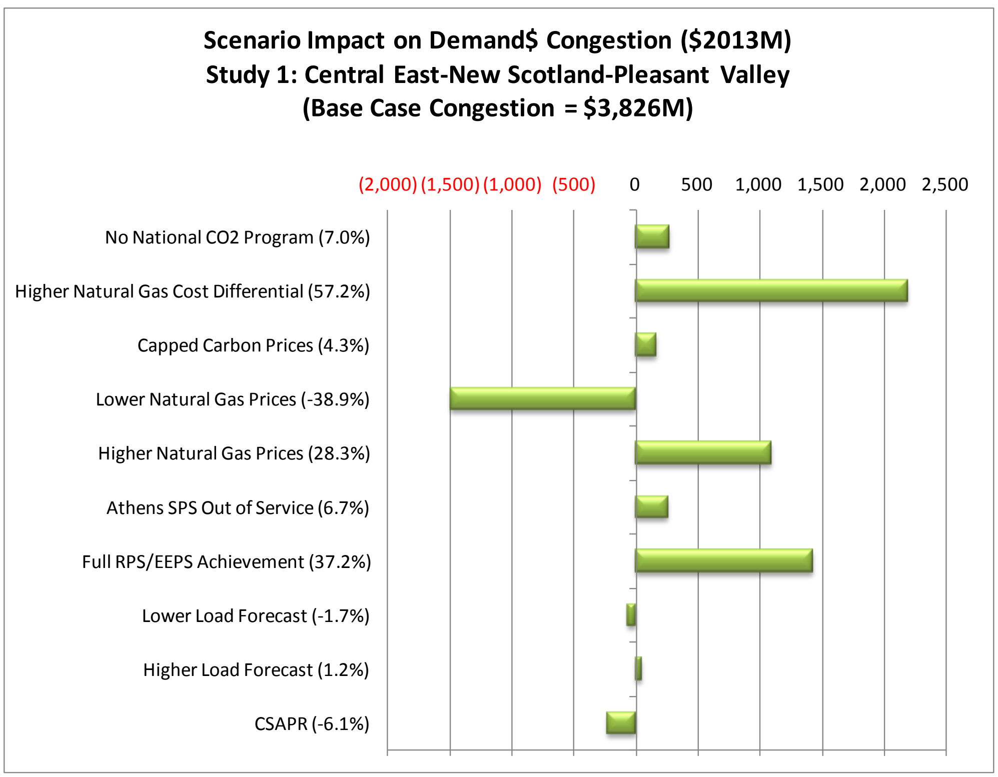


Figure 5-6: Scenario Impact on Central East –New Scotland - Pleasant Valley Congestion

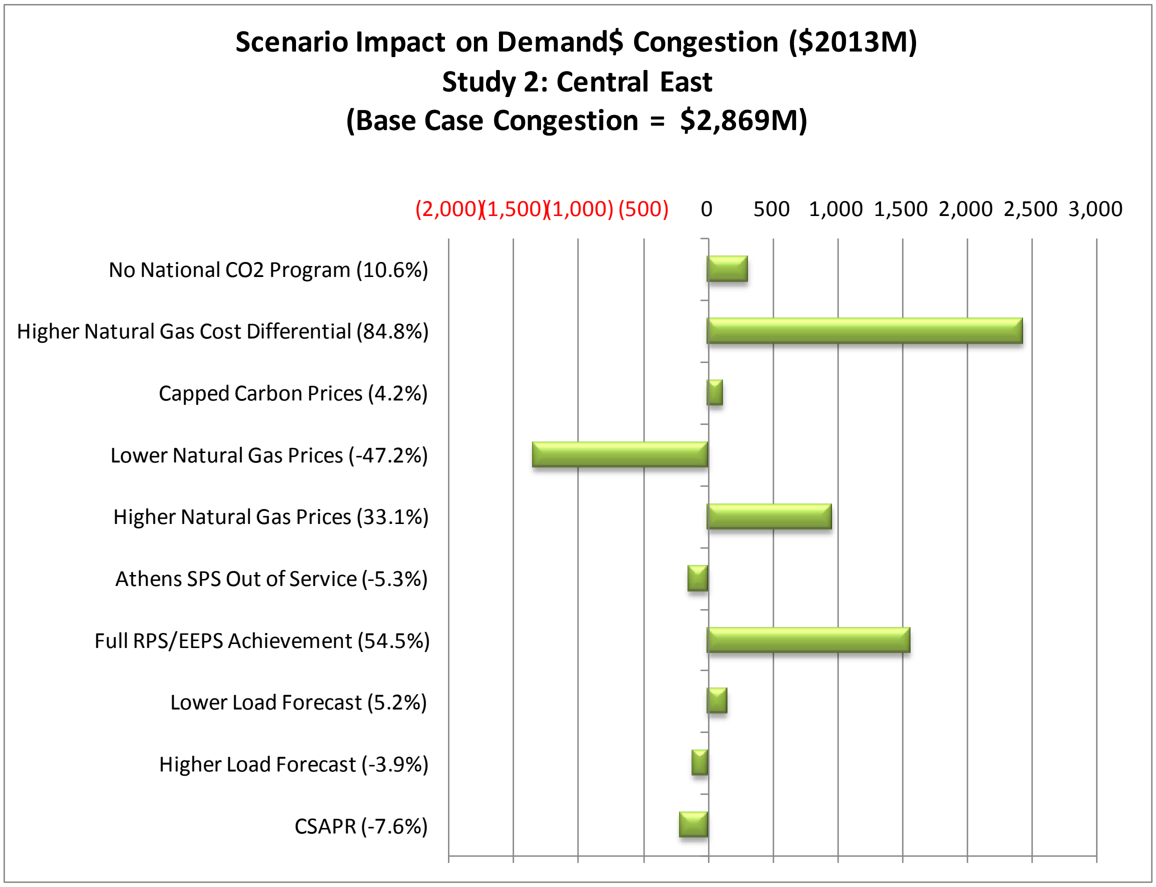


Figure 5-7: Scenario Impact on Central East Congestion

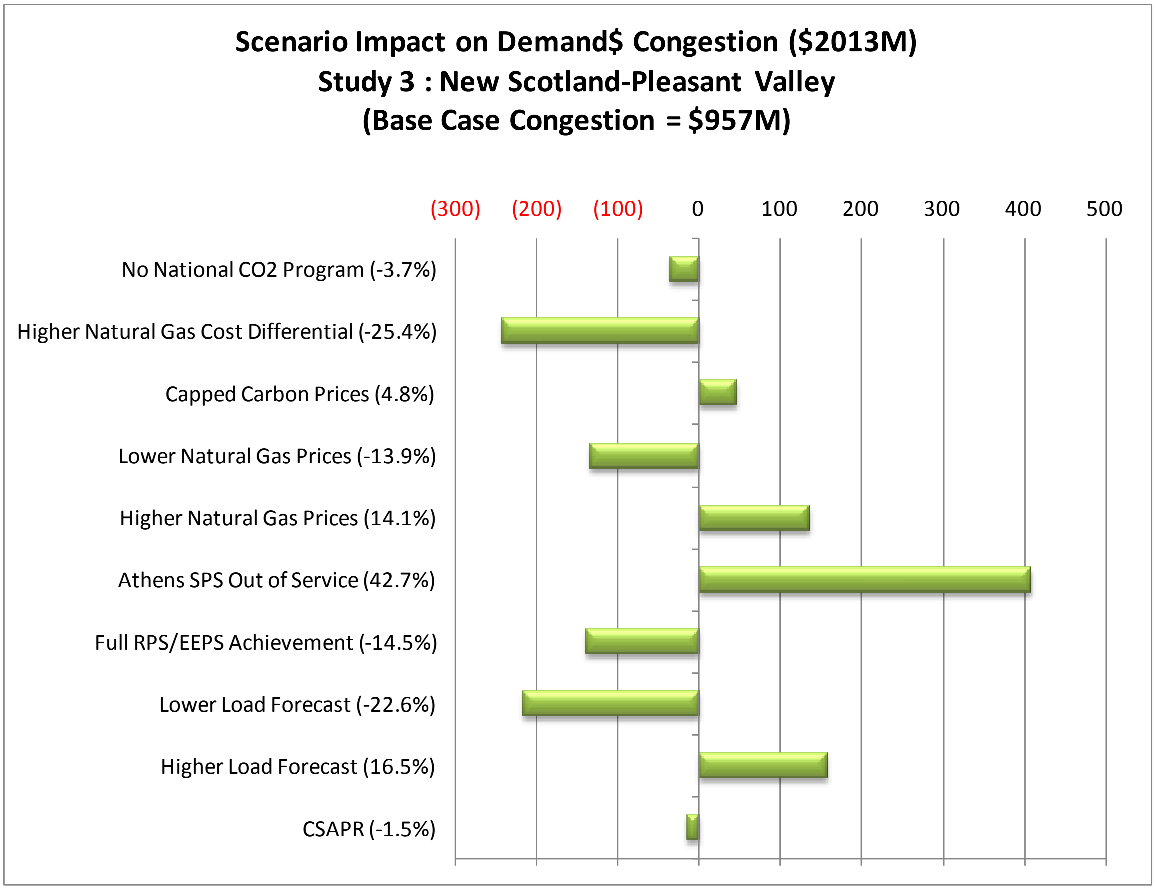


Figure 5-8: Scenario Impact on New Scotland – Pleasant Valley Congestion

Scenario 1: EPA Projected NOx and SO_2 Costs

Emissions of SO_2 and NOx have costs that are determined by various cap and trade programs currently in effect in New York and in most of the surrounding regions. Forecasts used in the base case for these allowance costs were developed using various private and public data such as some proprietary forecasts, and EPA's allowance price. To examine factors that might produce or increase congestion, the forecast costs of NOx and SO_2 emissions were modeled based on EPA projections for 2017 and 2022, resulting from the Cross-State Air Pollution Rule. The 2017 and 2022 NOx costs for this scenario were $949.93/ton and $1,337.21/ton. (The Base Case values were $97.19/ton and $124.87/ton for these years.) The 2017 and 2022 SO_2 costs for this scenario were $1,600.87/ton and $2,076.46/ton. (The Base Case values were $1,410.64/ton and $1,886.22/ton for these years.)

Scenario 2: Higher Load Forecast

This scenario examined the impact of the higher load forecast on the cost of congestion. The high load forecast is obtained from the 2013 Gold Book, and is 4% higher than the 2013 Gold Book Baseline load forecast used in the 2013 CARIS base case. The high load forecast is 36,142 MW and 38,369 MW respectively in 2017 and 2022. All other assumptions were kept the same as in the base case.

Scenario 3: Lower Load Forecast

This scenario examined the impact of the lower load forecast on the cost of congestion. The low load forecast is derived from the 2013 Gold Book, assumed the full achievement of the EEPS initiative and is 5% lower than the 2013 Gold Book Baseline load forecast used in the 2013 CARIS base case. The low load forecast is 33,097 MW and 34,558 MW respectively in 2017 and 2022. All other assumptions were the same as in the base case.

Scenario 4: Full RPS and EEPS Goals Achievement

This scenario adds renewable generation projects from the NYISO Interconnection queue to achieve the renewable goal of 9,870 GWh by 2015, and models load reductions which achieve the goal of 15% load reduction resulting in a peak load projection of 32,447 MW in 2015. This scenario only models the Market-Side component of the RPS program which comprises greater than the 95% of the MW target.

Scenario 5: Athens SPS Out of Service

This scenario assumed that the Athens SPS is not in service throughout the Study Period from 2013 -2022. The 2011 base case assumed that Athens SPS was in service. The Athens SPS system impact study in 2006 indicated a 450 MW increase in the transfer capability of the UPNY-SENY interface with the SPS in service.

Scenario 6: Higher Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be higher than the base case levels by one standard deviation. The standard deviation figures represent, for a given fuel, the typical volatility of daily prices around the monthly average based on an assessment of a 5-year history. The volatility of natural gas prices varies across the year such that it is most volatile in winter months. Consequently, as compared to the base case, the low price case uses January prices around 32% lower for Downstate, 28% for Midstate and 20% lower for Upstate, while remaining about the same in August in all cases.

Scenario 7: Lower Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be lower than the base case levels by one standard deviation. The standard deviation figures represent, for a given fuel, the typical volatility of daily prices around the monthly average based on an assessment of a 5-year history. The volatility of natural gas prices varies across the year such that it is most volatile in winter months. Consequently, as compared to the base case, the low price case uses January prices around 32% lower for Downstate, 28% for Midstate and 20% lower for Upstate, while remaining about the same in August in all cases.

Scenario 8: Lower CO_2 Emission Costs

To simulate the potential impact of carbon emission costs lower than those modeled in the base case, this scenario assumed the price of CO_2 allowances to not exceed $5/ton throughout the 2013-2022 Study Period.

Scenario 9: Higher Differential in Natural Gas Prices

To simulate the potential impact of an extension in recent trends in higher Capital zone and New England natural gas prices, this scenario assumed the differential in natural gas prices between Midstate/New England and Upstate was double the Base Case differential throughout the 2013-2022 Study Period.[27] This results in an increase in the Midstate price ranging from $0.63/MMbtu in 2013 to $1.03/MMbtu in 2022; and an increase in the New England price ranging from $0.65/MMbtu in 2013 to $1.05/MMbtu in 2022.

Scenario 10: No National CO2 Program

This scenario addresses the regulatory uncertainty concerning the adoption and/or timing of a national CO2 program and assumes that no program is implemented in either the non-RGGI states in the US or in IESO. It does assume that the RGGI program will persist through the Study Period for states currently enrolled.

[27] http://www.eia.gov/todayinenergy/detail.cfm?id=10791.

6. 2013 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 2013-2022 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, the four generic solutions were applied to each of the three study areas and production costs savings were calculated based on the three different ranges of generic costs. This 2013 study shows overall reduced levels of production cost savings for transmission and generation solutions as compared with the 2011 study.

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

Table 6-1: Base Case Projected Congestion 2013-2022

	Ten-Year Congestion ($M)	
Study	Nominal	Present Value ($2013)
Study 1: Central East-New Scotland-Pleasant Valley	5,409	3,823
Study 2: Central East	4,034	2,825
Study 3: New Scotland-Pleasant Valley	1,374	998

The application of the generic solutions to the three study areas all result in production cost savings expressed in 2013 present values, as shown in Table 6-2.

Table 6-2: Production Cost Savings (2013-2022, Present Value in 2013 $M)

	Ten-Year Production Cost Savings			
Study	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Study 1: Central East -New Scotland-Pleasant Valley	210	231	23	2,232
Study 2: Central East	116	57	20	1,114
Study 3: New Scotland-Pleasant Valley	72	231	15	2,214

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

Table 6-3: Benefit/Cost Ratios

	Solution	Low	Mid	High
CE-NS-PV	Transmission	0.59	0.24	0.16
	Generation	0.14	0.11	0.09
	Demand Response	0.11	0.08	0.06
	Energy Efficiency	0.95	0.71	0.57
		Low	Mid	High
CE	Transmission	0.56	0.23	0.16
	Generation	0.08	0.06	0.05
	Demand Response	0.20	0.15	0.10
	Energy Efficiency	1.21	0.91	0.73
		Low	Mid	High
NS-PV	Transmission	0.45	0.18	0.12
	Generation	0.14	0.11	0.09
	Demand Response	0.08	0.06	0.04
	Energy Efficiency	0.83	0.63	0.50

In conclusion, this CARIS Phase 1 study provides: (a) projections of congestion in the NYCA system; (b) present value of ten-year production cost savings ranging from \$15M to \$2,232M resulting from the application of various generic transmission, generation, energy efficiency and demand response solutions; and (c) the Benefit/Cost ratios as high as 1.21 and as low as 0.04 depending on the high-medium-low generic project cost estimates. All of the high and mid range cost estimates produced B/C ratios that are less than one and thus reflect the fact that their projected costs outweighed their estimated production cost savings over the Study Period. Only one of the low range cost estimates produced a B/C ratio greater than one. The energy efficiency solution for the Central East constraint produced a B/C ratio greater than one primarily because of its substantial impact on energy demand, which results in higher production cost savings relative to the other generic solutions analyzed.

Additionally, the scenario analyses provide information on new or increased projected congestion costs resulting from changes in variables selected for scenario analyses (see Appendix I).

7. Next Steps

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

7.1. Additional CARIS Studies

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

7.2. Phase 2 – Specific Transmission Project Phase

The NYISO staff will commence Phase 2 – the Project Phase – of the CARIS process following the approval of the Phase 1 report by the NYISO Board 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[28]. To qualify, the total capital cost of the project must exceed $25 million, the benefits as measured by the NYCA-wide production cost savings must exceed the project cost measured over the first ten years from the proposed commercial operation date, and a super-majority ($\geq$ 80%) of the weighted votes cast by the beneficiaries must be in favor of the project. Additional details on the Phase 2 process can be found in Appendix F.

7.3. Project Phase Schedule

The NYISO staff will perform benefit/cost analysis for submitted economic transmission project proposals for and, if a Developer seeks cost recovery, will determine beneficiaries and conduct cost allocation calculations. The results of the

[28] 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.

Phase 2 analyses will provide a basis for beneficiary voting on each proposed transmission project.

The next CARIS cycle is scheduled to begin in 2015.

Appendix A – Glossary

TERM	DEFINITION
Ancillary Services	Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or Voltage Support Service); Regulation Service; Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability. [FROM SERVICES TARIFF]
Bid Production Cost	Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (e.g., running cost, Minimum Generation Bid, and Start Up Bid). [FROM SERVICES TARIFF]
Bulk Power Transmission Facility (BPTF)	Transmission facilities that are system elements of the bulk power system which is the interconnected electrical system within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area.
Business Issues Committee (BIC)	A NYISO committee that is charged with, among other things, the responsibility to establish procedures related to the efficient and non-discriminatory operation of the electricity markets centrally coordinated by the NYISO, including procedures related to bidding, Settlements and the calculation of market prices.
Capacity	The capability to generate or transmit electrical power, or the ability to reduce demand at the direction of the NYISO.
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. It is the second step in the Comprehensive Reliability Planning Process (CRPP)
Comprehensive Reliability Planning Process (CRPP)	The biennial process that evaluates resource adequacy and transmission system security of the state's bulk electricity grid over a ten-year period and evaluates solutions to meet those needs. The CRPP consists of two studies: the RNA, which identifies potential problems, and the CRP, which evaluates specific solutions to those problems.
Comprehensive System Planning Process (CSPP)	A transmission system planning process that is comprised of three components: (1) Local transmission planning; (2) Compilation of local plans into the Comprehensive Reliability Planning Process (CRPP), which includes developing a Comprehensive Reliability Plan (CRP); (3) Channeling the CRP data into the Congestion Assessment and Resource Integration Study (CARIS)
Congestion	Congestion on the transmission system results from physical limits on how much power transmission equipment can carry without exceeding thermal, voltage and/or stability limits determined to maintain system

	reliability. If a lower cost generator cannot transmit its available power to a customer because of a physical transmission constraint, the cost of dispatching a more expensive generator is the congestion cost.
Congestion Rent	The opportunity costs of transmission Constraints on the NYS Bulk Power Transmission System. Congestion Rents are collected by the NYISO from Loads through its facilitation of LBMP Market Transactions and the collection of Transmission Usage Charges from Bilateral Transactions.
Contingencies	Electrical system events (including disturbances and equipment failures) that are likely to happen.
Day Ahead Market (DAM)	A NYISO-administered wholesale electricity market in which capacity, electricity, and/or Ancillary Services are auctioned and scheduled one day prior to use. The DAM sets prices as of 11 a.m. the day before the day these products are bought and sold, based on generation and energy transaction bids offered in advance to the NYISO. More than 90% of energy transactions occur in the DAM.
DC tie-lines	A high voltage transmission line that uses direct current for the bulk transmission of electrical power between two control areas.
Demand Response	A mechanism used to encourage consumers to reduce their electricity use during a specified period, thereby reducing the peak demand for electricity.
Eastern Interconnection Planning Collaborative (EIPC)	A group of planning authorities convened to establish processes for aggregating the modeling and regional transmission plans of the entire Eastern Interconnection and for performing inter-regional analyses to identify potential opportunities for efficiencies between regions in serving the needs of electrical customers.
Economic Dispatch of Generation	The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers.
Electric System Planning Working Group (ESPWG)	A NYISO governance working group for Market Participants designated to fulfill the planning functions assigned to it. The ESPWG is a working group that provides a forum for stakeholders and Market Participants to provide input into the NYISO's Comprehensive Reliability Planning Process (CRPP), the NYISO's response to FERC reliability-related Orders and other directives, other system planning activities, policies regarding cost allocation and recovery for reliability projects, and related matters.
Energy Efficiency Portfolio Standard (EEPS)	A statewide program ordered by the NYSPSC in response to the Governor's call to reduce New Yorkers' electricity usage by 15% of forecast levels by the year 2015, with comparable results in natural gas conservation. Also known as 15x15.
Exports	A Bilateral Transaction or purchases from the LBMP Market where the Energy is delivered to a NYCA Interconnection with another Control Area. [FROM SERVICES TARIFF]
External Areas	Neighboring Control Areas including HQ, ISO-NE, PJM, IESO
Federal Energy Regulatory Commission (FERC)	The federal energy regulatory agency within the US Department of Energy that approves the NYISO's tariffs and regulates its operation of the bulk electricity grid, wholesale power markets, and planning and interconnection processes.

FERC Form 715	An annual transmission planning and evaluation report required by the FERC – filed by the NYISO on behalf of the transmitting utilities in New York State.
FERC Order No. 890	Adopted by FERC in February 2007, Order 890 is a change to FERC's 1996 open access regulations (established in Orders 888 and 889). Order 890 is intended to provide for more effective competition, transparency and planning in wholesale electricity markets and transmission grid operations, as well as to strengthen the Open Access Transmission Tariff (OATT) with regard to non-discriminatory transmission service. Order 890 requires Transmission Providers – including the NYISO – have a formal planning process that provides for a coordinated transmission planning process, including reliability and economic planning studies.
Grandfathered Rights	The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party Transmission Wheeling Agreements (TWA) where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided in the Tariff, to retain those rights rather than to convert those rights to TCCs. [FROM SERVICES TARIFF]
Grandfathered TCCs	The TCCs associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party TWAs where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided by the Tariff, to convert those rights to TCCs. [FROM SERVICES TARIFF]
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.
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 first step in the NYISO's CRPP.
Security Constrained Unit Commitment (SCUC)	A process developed by the NYISO, which uses a computer algorithm to dispatch sufficient resources, at the lowest possible Bid Production Cost, to maintain safe and reliable operation of the NYS Power System.
Special Case Resource (SCR)	A NYISO demand response Demand Response program designed to reduce power usage by businesses and large power users qualified to participate in the NYISO's ICAP market. Companies that sign up to serve as SCRs are paid in advance for agreeing to reduce power consumption upon NYISO request.
Stakeholders	A person or group that has an investment or interest in the functionality of New York's transmission grid and markets.
Thermal transfer limit	The maximum amount of heat a transmission line can withstand. The maximum reliable capacity of each line, due to system stability considerations, may be less than the physical or thermal limit of the line.
Transfer Capability	The amount of electricity that can flow on a transmission line at any given instant, respecting facility rating and reliability rules.
Transmission Congestion Contract (TCC)	The right to collect, or obligation to pay, Congestion Rents in the Day Ahead Market for Energy associated with a single MW of transmission between a specified Point Of Injection and Point Of Withdrawal. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission. (SERVICES TARIFF TERM)
Transmission Constraint	Limitations on the ability of a transmission facility to transfer electricity during normal or emergency system conditions.
Transmission District	The geographic area served by the Investor Owned Transmission Owners and LIPA, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York. (SERVICES TARIFF TERM)
Transmission Interface	A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas. (SERVICES TARIFF TERM)
Transmission Owner (TO)	A public utility or authority that provides Transmission Service under the Tariff
Transmission Planning Advisory Subcommittee (TPAS)	A group of Market Participants that advises the NYISO Operating Committee and provides support to the NYISO Staff in regard to transmission planning matters including transmission system reliability, expansion, and interconnection.
Unhedged Congestion	Congestion payment (congestion component times load affected) minus the TCC hedge.

Exhibit No. NYT-7

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 12-E-0503 - Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans.

ORDER ACCEPTING IPEC RELIABILITY CONTINGENCY PLANS, ESTABLISHING COST ALLOCATION AND RECOVERY, AND DENYING REQUESTS FOR REHEARING

Issued and Effective: November 4, 2013

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Appendix A – Summaries of Notices and Comments

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on October 17, 2013

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Garry A. Brown
Gregg C. Sayre
Diane X. Burman

CASE 12-E-0503 - Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans.

ORDER ACCEPTING IPEC RELIABILITY CONTINGENCY PLANS, ESTABLISHING COST ALLOCATION AND RECOVERY, AND DENYING REQUESTS FOR REHEARING

(Issued and Effective November 4, 2013)

BY THE COMMISSION:

INTRODUCTION

This proceeding was commenced through a November 2012 Order that directed the development of utility plans to address the reliability concerns that may arise from the retirement of electric generating facilities.[1] In particular, the November 2012 Order recognized the significant reliability needs which could occur if the 2,040 MW of generating capacity at the Indian Point Energy Center (IPEC) were retired upon the expiration of

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[1] Case 12-E-0503, Generation Retirement Contingency Plans, Order Instituting Proceeding and Soliciting Indian Point Contingency Plan (issued November 30, 2012) (November 2012 Order).

IPEC's existing licenses.[2] Given the uncertainty regarding "whether Entergy will be able to obtain the necessary permits and approvals to keep [IPEC] operational over the long-term," the Commission sought a reliability contingency plan addressing those potential reliability needs.[3] The November 2012 Order directed Consolidated Edison Company of New York, Inc. (Con Edison), as the transmission owner most directly affected by the closure of the IPEC, to develop such a plan in consultation with the New York Power Authority (NYPA), Department of Public Service Staff (DPS Staff), and other appropriate agencies.[4]

In response to the November 2012 Order, Con Edison and NYPA jointly submitted a filing on February 1, 2013 (Con Edison/NYPA February Filing). The Con Edison/NYPA February Filing, as described in more detail below, proposed an IPEC Reliability Contingency Plan whereby Con Edison, New York State Electric and Gas Corporation (NYSEG), and NYPA would pursue the initial development of three Transmission Owner Transmission Solution (TOTS) projects, while concurrently soliciting generation and transmission proposals (other than the TOTS projects) through a Request for Proposals (RFP) to be issued by NYPA. The Con Edison/NYPA February Filing further described an Energy Efficiency (EE)/Demand Reduction (DR) program to obtain 100 MW of peak demand reduction. The TOTS upgrades, the 100 MW

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[2] The IPEC, which is located in Buchanan New York, consists of two base-load nuclear generating units that are currently owned by Entergy Nuclear Indian Point 2, LLC, and Entergy Nuclear Indian Point 3, LLC (collectively, Entergy). The Nuclear Regulatory Commission's licenses for IPEC Unit 2 and Unit 3 expire on September 28, 2013, and December 12, 2015, respectively.

[3] November 2012 Order, p. 3.

[4] On January 14, 2013, and prior to submitting their plan, a meeting was held by Con Edison and NYPA to provide their preliminary concepts for a reliability contingency plan, and to obtain input from interested stakeholders.

from EE and DR programs, and any projects accepted through the RFP process, were proposed as a portfolio to address a potential reliability need of approximately 1,450 MW that could arise in the 2016 summer period. Specifically, a June 1, 2016 reliability need date, when peak summer conditions could be expected to arise, was identified as an in-service date for projects that was consistent with the analysis performed as part of the 2012 Reliability Needs Assessment (RNA) conducted by the New York Independent System Operator, Inc (NYISO).[5]

The Con Edison/NYPA February Filing requested specific actions by the Commission, including: 1) an order in March 2013 requesting NYPA to issue an RFP for solutions to the potential energy reliability needs;[6] 2) an order in April 2013 authorizing the development of the 100 MW of EE and DR programs, the initial planning of the three TOTS projects, and the recovery of prudently incurred costs associated with planning the TOTS projects; and, 3) an order in September 2013 identifying a preferred set of transmission and/or generation projects for inclusion in the IPEC Reliability Contingency Plan, and making findings in connection with an authorization of cost allocation and cost recovery for such projects.[7]

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[5] The development of the June 2016 reliability need date, and of the extent of the potential need on that date, is discussed in more detail infra.

[6] The November 2012 Order, and the Notice Soliciting Comments issued on February 13, 2013, sought comments, by February 22, 2013, on the first requested action item (i.e., the issuance of the NYPA RFP, and related matters).

[7] The Con Edison/NYPA February Filing sought certain findings by the Commission, including findings that each of the TOTS projects would be a public policy project that meets the public policy requirements of New York State.

On March 15, 2013, the Commission issued an order that responded to the first requested action in the Con Edison/NYPA February Filing.[8] In particular, the March 2013 Order approved the proposal, subject to certain modifications, for NYPA to issue an RFP. The RFP was subsequently issued by NYPA on April 3, 2013, and responses to the RFP were received on or about May 20, 2013.

On April 19, 2013, the Commission responded to the second request in the Con Edison/NYPA February Filing, and approved, subject to conditions, Con Edison, NYSEG, and NYPA's preliminary planning related to the three TOTS projects.[9] While preliminary planning was approved for the TOTS, as described in the Con Edison/NYPA February Filing, the recovery of planning costs was capped at $10 million for an initial period until the TOTS projects were analyzed further.[10] In the April 2013 Order, Con Edison was also directed to work with the New York State Energy Research and Development Authority (NYSERDA) and NYPA, and to file a revised plan to secure permanent peak reduction from incremental EE and DR programs and other resources. Finally, the Order directed DPS Staff to propose a cost

[8] Case 12-E-0503, Generation Retirement Contingency Plans, Order Upon Review of Plan to Issue Request For Proposals (issued March 15, 2013) (March 2013 Order).

[9] Case 12-E-0503, Generation Retirement Contingency Plans, Order Upon Review of Plan to Advance Transmission, Energy Efficiency, and Demand Response Projects (issued April 19, 2013) (April 2013 Order). On February 20, 2013, a notice was published in the State Register, inviting comments on the second requested action items by April 8, 2013.

[10] At the time of the April 2013 Order, we declined to make the requested findings regarding consistency with public policy requirements, based on the unavailability of tariff provisions or procedures that could be applied. That conclusion, therefore, was without prejudice to a new request for findings, which could be made in this or another case before this Commission, or may be sought in another forum.

allocation and cost recovery mechanism for the Commission's consideration.

In response to the April 2013 Order, a revised plan for EE and DR programs was filed on June 20, 2013, by Con Edison and NYPA, in consultation with NYSERDA. The plan was comprised of 100 MW of EE and DR, which would be pursued by Con Edison and NYSERDA, and 25 MW of Combined Heat and Power (CHP) projects to be administered by NYSERDA (collectively, the 125 MW Revised EE/DR/CHP Program). The 125 MW Revised EE/DR/CHP Program, along with 60 MW from other on-going projects identified by NYSERDA and NYPA, which had not been counted in the NYISO's 2012 RNA, were estimated to provide 185 MW of relief toward the potential reliability deficiency. DPS Staff also submitted a proposed cost allocation/cost recovery straw proposal on June 4, 2013 (DPS Staff June Straw Proposal). The 125 MW Revised EE/DR/CHP Program and the June Straw Proposal are discussed further below.

In this Order, we address, in part, the third and final requested action item in the Con Edison/NYPA February Filing by accepting a portfolio for inclusion in the IPEC Reliability Contingency Plan consisting of: 1) the three TOTS projects; and 2) the development of approximately 125 MW of EE/DR/CHP resources through the 125 MW Revised EE/DR/CHP Program. This portfolio, along with 60 MW from on-going EE, DR, and CHP activities, makes a total contribution of 185 MW from EE, DR, and CHP programs towards the potential reliability need for 1450 MW in June 2016.[11] We anticipate that the TOTS will contribute at least an additional 600 MW towards that need.

As noted above, the April 2013 Order approved the issuance of an RFP seeking proposals for generation or non-TOTS transmission projects which could be included in the IPEC Reliability Contingency Plan portfolio. In response to the RFP, a significant number of proposals were received, and these proposals have been evaluated by DPS Staff with the assistance of a consultant, The Brattle Group, Inc. (Brattle).

For the time being, however, we agree with DPS Staff's recommendation to defer the choice of which, if any, of the proposals responding to the NYPA RFP should be included in the IPEC Reliability Contingency Plan portfolio. We leave this issue open in light of the uncertainties presently affecting the wholesale generation markets. First, in the coming months, it is possible that the NYISO will establish a new Installed Capacity (ICAP) Zone in the Lower Hudson Valley to meet Locational Capacity Requirements. Second, the NYISO is developing new "Demand Curves" for use in setting ICAP prices in the NYISO-administered markets. Both of these actions are very likely to increase ICAP prices that generators can expect to

[11] In connection with the filing of the 125 MW Revised EE/DR/CHP Program, additional DR and CHP projects providing a total of 60 MW have been identified, which are expected to be available by the summer 2016, but were not accounted for in the NYISO's 2012 RNA. For purposes of evaluating the portion of the reliability gap which is met by new EE, DR, and CHP activities, we will count the estimated results of these programs in the analysis. The programs providing these 60 MW, however, are already on-going and have an identified source of funding associated with them, so no action in this Order is needed for their implementation. The 60 MW from these programs breaks down as: (a) an additional 15 MW of peak demand reductions as part of a separate NYPA Build Smart NY Program, (b) an additional 15 MW of on-going CHP projects at NYPA, and (c) 30 MW of CHP projects through a NYSERDA program which has already been approved by the Commission.

receive in the Lower Hudson Valley. At the same time, there are several merchant generating units, with a combined capacity of approximately 1,500 MW, which could serve this market, but have either been mothballed and are waiting to return to service if economic conditions improve, or have been subject to a forced outage or have been derated and require repair. With the potential to participate in a higher revenue stream, some of the owners of these units could decide in the near future to bring their units back into service. If so, these units would contribute to meeting the reliability needs, thus reducing the amount of resources necessary to include in the IPEC Reliability Contingency Plan portfolio.

As discussed below, we agree with DPS Staff's recommendation to include the TOTS projects and the EE, DR, and CHP projects described above in the portfolio of projects accepted for inclusion in the IPEC Reliability Contingency Plan. If accepted now and, if timely implemented, the TOTS projects and the 125 MW Revised EE/DR/CHP Program provide a significant portion of the resources needed to address the potential reliability needs in the event IPEC is retired in December 2015. This Order accepts this limited suite of projects as the appropriate least-cost and least-risk portfolio for the IPEC Reliability Contingency Plan at the present time.

This Order also addresses the method by which the costs associated with implementing the herein accepted components of the IPEC Reliability Contingency Plan should be allocated, and the mechanisms by which those costs should be recovered. Finally, we address the Requests for Rehearing of the March 2013 Order and the April 2013 Order. For the reasons discussed below, we deny these requests.

BACKGROUND

Con Edison/NYPA February Filing

A. TOTS Projects

The first component of the contingency plan proposed in the Con Edison/NYPA February Filing consisted of three TOTS projects that Con Edison and NYPA asserted could be implemented by the summer of 2016. In particular, Con Edison described its plan to develop a second Ramapo to Rock Tavern transmission line (Ramapo/Rock Tavern), and a Staten Island Unbottling (Staten Island) project. The third project, referred to as the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring (Marcy/Fraser) project, would be developed by NYPA and NYSEG.[12]

According to the Con Edison/NYPA February Filing, as updated on May 20, 2013, two of the TOTS projects (i.e., the Ramapo/Rock Tavern line and the Marcy/Fraser project) would increase the import capability into Southeastern New York by reducing the constraint on the Upstate New York/Southeast New York interface. This means that underutilized upstate capacity would be able to provide increased levels of energy to the downstate area and this increased capability would provide a reliability benefit. The third proposed TOTS, i.e., the Staten Island unbottling project, is designed to make generation on Staten Island, which is currently bottled, available to the grid and deliverable to Con Edison’s Gowanus and Farragut transmission substations.[13]

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[12] The three TOTS are discussed in detail in Exhibits B, C, and D of the Con Edison/NYPA February Filing, and the update filed on May 20, 2013.

[13] Generation that is “bottled” is physically interconnected, but cannot provide its full output to the grid due to transmission limitations.

The Con Edison/NYPA February Filing sought full recovery of the costs, including any associated contractual cancellation costs, incurred by Con Edison and NYPA for these projects. Con Edison and NYPA provided estimates of the costs to halt the TOTS projects at selected intervals and of the costs to complete each of these projects. The total cost to complete these projects was initially estimated at approximately $511 million. Based on updates filed on May 20, 2013, the cost of the Staten Island project was revised downward, making the total estimated cost of the three TOTS projects approximately $447 million. According to the Con Edison/NYPA February Filing, the TOTS projects would ultimately be transferred to and owned by an entity identified as the “New York Transmission Company” (NY Transco).

Con Edison, together with the other New York investor-owned transmission companies, and NYPA and the Long Island Power Authority (LIPA) (collectively the New York Transmission Owners or NYTOs), are active participants in the process of creating the NY Transco. The NY Transco’s purpose and structure are intended to address and overcome planning and cost allocation issues which have, to date, impeded the development of economic transmission projects. The NY Transco would be a new entity formed for the express purpose of developing transmission projects in the State. However, while the NY Transco has not yet been formed, on May 30, 2012, and in response to the New York State Energy Highway Request for Information, the NYTOs identified eighteen transmission projects throughout the State that the NY Transco could develop.[14] The identified projects included the three TOTS projects under consideration here.

B. EE/DR/CHP Programs

The second component of the IPEC Reliability Contingency Plan, as initially presented by Con Edison and NYPA, included a targeted program to achieve 100 MW of permanent peak demand reduction by the summer of 2016. NYPA also identified 15 MW of on-going CHP projects that would be placed in-service by the summer of 2016.

The EE and DR components of the Con Edison/NYPA February Filing were subsequently supplanted with the 125 MW Revised EE/DR/CHP Program proposed by Con Edison and NYSERDA, in consultation with NYPA. The 125 MW Revised EE/DR/CHP Program, filed on June 20, 2013, seeks approval for 100 MW of peak EE/DR and fuel switching projects, which would be coordinated by Con Edison and NYSERDA, along with a 25 MW expanded CHP program that would be administered by NYSERDA.

The EE and DR components of the 125 MW Revised EE/DR/CHP Program would be located within Con Edison's service territory, and are broken down into 44 MW for load management, 40 MW for permanent demand reduction, and 16 MW for fuel switching, for a total of 100 MW. These projects are estimated to cost $219 million, and these costs are proposed to be

[14] See, http://www.nyenergyhighway.com/RFIDocument/transmission/index-2.html. The 18 projects identified by NY Transco could result in an estimated total investment of $2.9 billion in upgrades across the New York State transmission system. Neither the creation of, nor the formation of, nor any specific property transfer to the NY Transco is under review in this Order.

recovered through a surcharge on Con Edison’s delivery customers.[15]

The Revised EE and DR components would be jointly implemented by Con Edison and NYSERDA, and are expected to result in a “single point of entry for all participants,” with a single application process. These programs would focus on large customers located within Con Edison’s service territory. Targeted customers would include: (1) customers with high peak demand; (2) project developers with potential large scale projects; (3) prior or existing Energy Efficiency Portfolio Standard participants that may be willing to expand the scope and depth of projects; and (4) customers capable of switching electric summer air conditioning load to steam or gas.

The Revised EE/DR/CHP Program also included a NYSERDA proposal for an Expanded NYSERDA CHP component for the Program. This aspect of the Program is designed to achieve 25 MW of load reduction. The total cost to ratepayers of the 25 MW Expanded NYSERDA CHP Program is expected to be $66 million, which is broken down to include: 1) $40 million for customer incentives; 2) $16 million for Outreach Assistance Contractor activities; and, 3) $10 million for administrative functions such as NYSERDA staff salaries and State Cost Recovery Fee and Program Evaluation tasks. The total cost for the 125 MW of projects proposed for acceptance in the 125 MW Revised EE/DR/CHP Program would be approximately $285 million.

As part of the filing that included the 125 MW Revised EE/DR/CHP Program, NYSERDA indicated that the 25 MW of proposed CHP projects was in addition to the CHP projects that the

[15] The surcharge would exclude NYPA’s governmental customers who receive delivery service under Con Edison’s PSC NO. 12 – Electricity, since they already participate in the NYPA Build Smart NY Program.

Commission previously approved.[16] DPS Staff verified with NYSERDA that 30 MW of these previously approved CHP projects would be operational in Con Edison's service territory by June 2016, and that they were not included in the NYISO's 2012 RNA. In addition, NYPA identified an additional 15 MW that would be achieved under NYPA's Build Smart NY program, which were not identified in the NYISO's 2012 RNA but would be in-service by the summer of 2016. These MW reductions would come from a mix of efficiency gains at state agencies and authorities, wastewater treatment plants in New York City, and campus-wide American Society of Heating, Refrigerating and Air Conditioning Engineers-Level II audits. All NYPA Energy Efficiency Program projects are funded through NYPA low-cost financing that is recovered directly from program participants. As such, the cost of implementing these projects would not be funded through utility tariff charges.

Taken together, all of these projects, including the 15 MW of ongoing CHP projects NYPA identified in the Con Edison/NYPA February filing, would contribute toward meeting the calculated reliability deficiency needs.[17] Cumulatively, the 125 MW of projects proposed in the Revised EE/DR/CHP Program, and

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[16] The Commission's previous approval was in Case 07-M-0548, Energy Efficiency Portfolio Standard – System Benefit Charge IV, Order Modifying Budgets and Targets for Energy Efficiency Portfolio Standard Programs and Providing Funding for Combined Heat and Power and Workforce Development Initiatives (issued December 17, 2012).

[17] As noted above, NYSERDA and NYPA have identified other programs which have already been approved and are funded, but the results of which have not been counted in the NYISO RNA. These programs should contribute approximately 60 MW towards the reliability goal associated with the IPEC Reliability Contingency Plan. See note 11, supra.

the 60 MW from on-going projects[18], would contribute 185 MW toward the potential reliability deficiency need.

On July 17, 2013, a notice was published in the State Register, inviting comments on the Revised EE/DR/CHP Program. Various comments were received by the deadline of September 3, 2013.

DPS Staff Cost Allocation/Cost Recovery Proposal

In response to the April 2013 Order, DPS Staff filed the June Straw Proposal, which described a methodology as to how the costs associated with implementing the transmission or generation solutions that are ultimately part of the IPEC Reliability Contingency Plan could be allocated and recovered from retail ratepayers. At the same time, DPS Staff also provided and sought comments on a draft Reimbursement Agreement prepared by NYPA, which NYPA described as "a necessary component of the mechanism that will be needed to ensure full recovery of costs incurred in connection with the [TOTS] and with generation project(s), if any, selected pursuant to the April 3, 2012 [RFP]."

DPS Staff's June Straw Proposal sought to allocate costs by applying a "beneficiaries pay" principle, whereby the ratepayers that receive the reliability benefits from the IPEC Reliability Contingency Plan would be assigned a proportionate cost recovery responsibility. The June Straw Proposal also attempted to maintain consistency, to the extent practicable, with the NYISO's tariff provisions for allocating the costs of a transmission solution selected to fulfill a need identified in a NYISO Reliability Needs Assessment.

Pursuant to the Notice of Second Technical Conference and Revised Comment Schedule, issued on July 2, 2013, initial comments were sought by July 22, 2013, and reply comments were

[18] See, supra at note 11.

sought by August 5, 2013. Several comments were received in response to this notice.

DISCUSSION

Statutory Authority

With this Order, the Commission accepts a Reliability Contingency Plan that identifies a portfolio of specific transmission and EE/DR/CHP projects that, when taken together, will significantly reduce New Yorker's vulnerability to the costs and disruptions that could occur upon the retirement of IPEC Unit 3 in December 2015. In addition, the Order establishes the methods and mechanisms for the allocation and recovery of the costs and benefits associated with the implementation of the IPEC Reliability Contingency Plan.

Comments have been received in this proceeding in response to several notices seeking comments. These notices are summarized, along with the comments, in Appendix A to this Order. Some commenters expressed concern that the DPS Staff's June Straw Proposal for allocating costs would intrude into Federal Energy Regulatory Commission (FERC)-regulated markets, and would interfere with NYISO operating and planning processes, as well as unnecessarily duplicate, preempt, or nullify portions of the NYISO tariff. Other commenters argued that FERC, and not the Commission, has jurisdiction over cost allocation. These commenters further argued that the Commission lacks authority under the Public Service Law (PSL) for establishing a cost allocation methodology, and that our jurisdiction has not been established on this issue. It is also noted that this Commission lacks jurisdiction over NYPA; that NYPA lacks the authority assumed in the June Straw Proposal; that the Commission has limited jurisdiction over LIPA; and finally, that FERC has exclusive jurisdiction over the proposed TOTS projects.

However, others claim that cost allocation has been delegated to the Commission under the NYISO's compliance filing pertaining to FERC's Order 1000.

Contrary to some parties' arguments, the Commission's authority to adopt and provide for the implementation of this IPEC Reliability Contingency Plan is well founded in the PSL. In particular, section 5(2) of the PSL provides the Commission with authority to "encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."[19] Moreover, section 66(5) of the PSL provides the Commission with authority to address reliability concerns by prescribing the "safe, efficient and adequate property, equipment and appliances thereafter to be used," whenever the NYPSC determines that the utility's existing equipment is "unsafe, inefficient or inadequate."[20] The Commission also has authority to "order reasonable improvements and extensions of the works, wires, poles, lines, conduits,

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[19] Section 5(2) of the PSL has been held to confer "broad discretion" to promote energy conservation. See, Multiple Intervenors v. NYPSC, 166 A.D.2d 140 (3rd Dept. 1991). Furthermore, PSL §5(2) was determined to provide the Commission with jurisdiction to require utilities to file plans outlining how they would adapt to a competitive electric industry. See, Energy Association of New York State v. NYPSC, 169 Misc. 2d 924 (Supreme Ct. 1996)(noting that PSL §5(2) transformed "the traditional role of the Commission from that of an instrument for a simple case-by-case consideration of rates requested by utilities to one charged with the duty of long-range planning for the public benefit").

[20] PSL §66(5). "Electric corporations" are required to provide "such service, instrumentalities and facilities as shall be safe and adequate." PSL §66(1).

ducts and other reasonable devices, apparatus and property of...electric corporations and municipalities.”[21] Other provisions of the PSL also provide the Commission with authority over reliability.[22]

Moreover, the Commission’s authority to protect or enhance reliability, as it exercises here by accepting the IPEC Reliability Contingency Plan, is expressly preserved under the Federal Power Act. As stated therein, FERC’s authority to establish reliability standards “shall [not] be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any [FERC-approved] reliability standard, except that the State of New York may establish rules that result in greater reliability within that State, as long as such action does not result in lesser reliability outside the State than that provided by the [FERC-approved] reliability standards.”[23] We find that the IPEC Reliability Contingency Plan usefully defines measures needed to ensure safety, adequacy, and reliability, and may result in greater reliability in New York than would otherwise exist under the FERC-approved reliability standards. Accordingly, our

[21] PSL §66(2). The NYPSC has continuing jurisdiction over the "construction, operation and maintenance of all utility transmission lines.” See, Matter of Stannard v. Axelrod, 100 Misc.2d 702 (Sup. Ct. Broome Co. 1979) (dismissing petition challenging the NYPSC's Order approving a 345 kilovolt transmission line).

[22] See, PSL §§25(4) and 25-a(5) (allowing the NYPSC to impose penalties upon a public utility that fails to comply with regulations related to reliability); see also, PSL §126(1)(d) (providing that before the NYPSC may site a major electric utility transmission facility, the Commission must find that such facility “will serve the interests of electric system economy and reliability”).

[23] 16 U.S.C. §824o(i)(3).

authority to accept the IPEC Reliability Contingency Plan is not preempted by FERC or the NYISO planning process.

In addition, the Commission has authority to ensure that "[a]ll charges made or demanded by any...electric corporation or municipality for…electricity or any service rendered or to be rendered, shall be just and reasonable and not more than allowed by law or by order of the commission."[24] As the April 2013 Order stated, the Commission possesses the "authority to develop a retail rate recovery mechanism that provides for the jurisdictional utilities to collect payments from their ratepayers for reliability-related activities."[25] The Commission also concluded that "this funding may be used to support actions taken by NYPA in support of their reliability-related activities undertaken in conjunction with the Indian Point Contingency Plan."[26] The Commission further noted that it was not "asserting jurisdiction over NYPA, the rates NYPA charges its customers, or wholesale transmission rates established by FERC." We conclude that these findings continue to adhere to the rulings in this Order.

With respect to cost allocation and recovery for the TOTS projects, however, we do not need to exercise our legal authority to decide the cost allocation and recovery issues. We understand from the NYTO's comments that the TOTS project developers, together with the other NYTOs which are proposed members of the NY Transco, intend to seek cost recovery for the TOTS through FERC-approved tariffs. The TOTS developers have also indicated that they intend to propose a cost allocation methodology to FERC that is consistent with the methodology developed by the NYTOs in connection with the NY Transco

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[24] PSL §65(1).

[25] April 2013 Order, p. 10.

[26] Id.

concept. We concur with the NYTOs that cost recovery and allocation through a FERC tariff are appropriate for these projects, and we intend to support such an application regarding the TOTS projects in so far as the application's proposed revenue requirement reflects the cost estimates and cost allocation methodology set forth in the NYTOs' filings in this proceeding. We urge the NYTOs to proceed as quickly as possible at FERC. In connection with that application, we will direct Con Edison, in consultation with NYPA, to supply a report on the progress of this application on or before June 30, 2014, and every six months thereafter.

Identification of Reliability Needs

The reliability implications of retiring IPEC have been well documented by the NYISO. While the NYISO assumed that IPEC was available in the 2012 RNA base case, it performed a further analysis with IPEC unavailable. This analysis found that "reliability violations would occur in 2016 if the Indian Point Plant were to be retired by the end of 2015."[27] The NYISO's 2012 RNA transmission security analysis indicated that, without Indian Point, already constrained transfer limits into Southeastern New York would be further aggravated.[28] In order to mitigate these overloads, the NYISO stated that compensatory megawatts would be needed in Zones G, H, I, J, or the western

[27] New York Independent System Operator 2012 Reliability Needs Assessment, Final Report, dated September 18, 2012, p. 42.

[28] Specifically, a transmission security analysis indicated overloaded conditions on the Leeds-Pleasant Valley and Athens-Pleasant Valley 345 kV lines, the Fraser-Coopers Corners and Rock Tavern-Ramapo 345 kV lines, and the Roseton-East Fishkill 345 kV line.

portion of Zone K,[29] amounting to 1,000 MW in 2016, noting that the amount of compensatory megawatts could increase depending on the location of the resource.[30]

Finally, the NYISO's 2012 RNA Indian Point Plant Retirement Scenario showed significant Loss of Load Expectation (LOLE)/resource adequacy violations if Indian Point were not available. Using the base case load forecast, the 2016 LOLE would be 0.48 days per year. This represented a significant violation of the 0.1 days per year criterion.[31]

The Con Edison/NYPA February Filing stated that it relied on the NYISO's 2012 RNA base case as the starting point for its analysis, noting that it is the NYISO's most recent evaluation of the bulk power system over the next ten years.[32] According to the filing, the base case was then updated by adjusting for known additions and retirements since the NYISO analysis was performed. Specifically, the NYISO's 2012 RNA base case was adjusted by adding 320 MW associated with the rescission of a mothball notice by Astoria Generating Company, L.P.'s Gowanus barges 1 and 4, and reducing the reliability deficiency need amount to reflect the effect of the 100 MW EE/DR

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[29] The location of these Zones in New York State can be understood from a map at the NYISO website. See, http://www.nyiso.com/public/markets_operations/market_data/maps/index.jsp.

[30] New York Independent System Operator 2012 Reliability Needs Assessment, Final Report, dated September 18, 2012, p. 43.

[31] The New York State bulk power system is planned to meet a LOLE that, at any given point in time, is less than or equal to a involuntary load disconnection that is not more frequent than 0.1 days per year. In other words, the bulk power system is planned so that there is sufficient transmission and generation such that the LOLE is no more than once every 10 years.

[32] Con Edison notes that the RNA model and assumptions were a result of extensive stakeholder review.

peak load reduction program proposed in the Con Edison/NYPA February Filing. The results of the analysis, as indicated in the Con Edison/NYPA February Filing, showed a deficiency of 950 MW, as compared to the NYISO 2012 RNA analysis, which showed a deficiency of approximately 1,000 MW.

As Con Edison's analysis was nearing completion, however, the retirement of the Danskammer generating facility was announced. Based on this announcement in January 2013, the effect of this retirement was estimated by Con Edison to increase the reliability needs by an additional 400-425 MW, making the total deficiency approximately 1,450 MW (or approximately 1,350 MW accounting for the effect of the initial proposed 100 MW EE/DR program).

In order to conduct an independent analysis and update of the reliability deficiency needs and to perform other work which would be useful for Staff's Contingency Plan analysis, as directed in the March 2013 Order, DPS Staff obtained the consulting services of Brattle. Thereafter, DPS Staff directed Brattle to analyze the reliability needs that would attend the retirement of the IPEC at the end of 2015. DPS Staff indicated that the updated base case in the analysis should model NRG Energy, Inc's Astoria Gas Turbine Units 10 and 11, which are expected to return to service.[33] Based on the analysis, DPS Staff confirmed the validity of the reliability needs identified in the Con Edison/NYPA February Filing, and that if IPEC Units 2 and 3 were to retire upon the expiration of its current licenses in 2013 and 2015, respectively, Southeast New York would not have enough capacity to avoid reliability violations in the summer of 2016.

[33] On June 7, 2013, NRG Energy, Inc. filed, in Case 05-E-0889, a notice of intent to return Astoria Gas Turbine Units 10 and 11 to service.

Contrary to parties' claims, we find that the various analyses performed of the potential reliability impacts associated with the retirement of IPEC provide a sufficient record and a rational basis to identify a reliability deficiency need of approximately 1,450 MW. We reject, however, parties' suggestions that the Commission should rely on the NYISO planning process to resolve these potential reliability needs, or that we should not plan for the contingency that IPEC may be retired.[34] As observed in the March 2013 Order, the NYISO's process currently assumes that IPEC will remain available, and therefore, it is not conducting the reliability contingency planning that we are conducting now.[35] We disagree that a reasonable planning approach under the circumstances should rely solely on market-based projects to appear, or that we should wait for the NYISO to "trigger" the need for the implementation of a reliability solution. In the event IPEC were unable to obtain the necessary consents and approvals to continue operating, or if Entergy could decide that continued operation of IPEC is not in its interest,[36] there would unlikely be sufficient time to address the resulting reliability needs.

The requirement that the projects included in the IPEC Reliability Contingency Plan meet a firm in-service deadline of June 1, 2016 comports with the NYISO's identified reliability

[34] We reiterate that the Commission is not making any determinations or taking any positions regarding the potential closure of the IPEC. See, November 2012 Order, fn 3.

[35] Under the NYISO's procedures, it will not assume that IPEC will be unavailable until Entergy, the owner and operator of the IPEC, provides a retirement notice.

[36] Entergy recently announced that due to economic factors it was retiring its Vermont Yankee nuclear reactor by the end of 2014, leaving regulators with as little as 16 months to address any reliability needs associated with the retirement. See, http://www.nytimes.com/2013/08/28/science/entergy-announces-closing-of-vermont-nuclear-plant.html?_r=0

need date under the “IPEC retirement scenario”. Therefore, the in-service requirement based on this date is consistent with the need to maintain safe and adequate service in the event IPEC is retired.

We also reject parties’ arguments that we have failed to reflect or accommodate market-based projects that are currently under development that could, when completed, contribute to meeting the identified reliability needs. The analysis of need took into account the most recent information available regarding proposed projects. To the extent any proposed projects have met the milestones established by the NYISO’s planning criteria for inclusion in the RNA base case, those projects were assumed to be available.[37]

Reliability Contingency Plan - Portfolio of Projects

The components of the IPEC Reliability Contingency Plan portfolio which we accept here will, according to DPS Staff’s analysis, contribute toward the potential reliability need, while offering net benefits for ratepayers even if IPEC were to operate beyond December 2015. DPS Staff opines that it is in the public interest to pursue these projects, regardless of the contribution they make to the IPEC Reliability Contingency Plan.[38] These projects include the three TOTS, which are estimated to provide at least 600 MW of reliability relief.. DPS Staff also recommends that we advance the proposal in the

[37] Indeed, our decision to defer considerations of the proposals submitted under the NYPA RFP arises from our understanding that market conditions are changing and may result in the development of market-based solutions. See supra at Section I.

[38] Con Edison referred to some of these projects as “no regrets” solutions to the retirement of the IPEC, meaning that the projects provide net benefits to ratepayers even if IPEC does not retire. See, Con Edison Filing of Supplemental Information Regarding its Ramapo to Rock Tavern Project (filed May 20, 2013).

125 MW Revised EE/DR/CHP Program to achieve the estimated 100 MW associated with EE and DR programs and approximately 25 MW from new NYSERDA CHP programs, as being consistent with the public interest and prior Commission decisions.[39]

A. TOTS Projects

Under DPS Staff's direction, Brattle examined the benefits and costs of the three TOTS projects. For this assignment, Brattle was asked to assume that IPEC continued to operate in order to determine whether potential net benefits would be associated with the TOTS projects under this more conservative assumption. To complete this evaluation, independent estimates of the resource cost savings were derived for each of the TOTS projects individually, as well as for all three combined.

To compare the TOTS costs and benefits, DPS Staff directed Brattle to convert the TOTS investment costs, as estimated by Con Edison and NYPA, into typical utility annual revenue requirements.[40] The energy resource cost savings were modeled using General Electric's Multi-Area Production Simulations (GE MAPS). Capacity resource cost impacts were estimated by Brattle and DPS Staff based on the modeling of NY's existing and proposed capacity markets.

The net benefits of the TOTS were calculated as the difference between resource cost savings and the total revenue requirements associated with the projects. Because annual revenue requirements begin at their highest level and decrease

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[39] See, Case 10-M-0457, et al., System Benefits Charge IV, Order Continuing the System Benefits Charge and Approving an Operating Plan for a Technology and Market Development Portfolio of System Benefits Charge Funded Programs (issued October 24, 2011).

[40] The revenue requirement includes estimates of on-going operation and maintenance costs and property taxes.

each year, and because resource cost savings were estimated to increase over time, estimated net savings increase over time. Thus, for the first 15 years of asset life, DPS Staff estimated net benefits to have a net present value (NPV) of approximately $260 million in 2016 dollars. For the full 40 years of rate recovery, the NPV of net benefits was estimated to be approximately $670 million.[41] DPS Staff indicates that if IPEC were retired, the estimated net benefits of the TOTS projects are expected to be higher.

From this information, DPS Staff concluded that, even if IPEC is not retired, the benefits of each TOTS project would be greater than its costs individually, and that the benefits for all three projects together would exceed their combined costs. DPS Staff also determined that the net benefits of the TOTS projects would be even greater if IPEC were not available in 2016 and beyond. Based on its findings that either scenario would provide net benefits for ratepayers, DPS Staff recommends that the TOTS projects should be pursued.

Implementing the three TOTS projects is expected to contribute at least 600 MW toward the reliability relief which may be necessary if IPEC is shut down. The reliability benefits of the Ramapo/Rock Tavern line and the Marcy/Fraser project would be created in greater or lesser measure whether or not IPEC retires. Further, even if IPEC does not retire, and the TOTS are not required to avoid reliability violations, the increased transfer capability from these projects would still provide economic benefits by supplying lower cost energy from upstate sources to downstate consumers. The Staten Island unbottling project responds to Con Edison’s in-city contingency planning needs, by decreasing the amount of in-city capacity Con

[41] DPS Staff notes that the estimates of annual benefits are more uncertain as more distant time periods are analyzed.

Edison needs to operate its system securely. This will also allow certain generators to run more, saving system resource costs.

We agree with DPS Staff's recommendation and accept the inclusion of the three TOTS projects in the portfolio for the IPEC Reliability Contingency Plan. Significantly, DPS Staff's analysis shows that the net benefits for ratepayers are available even if IPEC is not retired. We expect that Con Edison, NYSEG, and NYPA will proceed with the necessary permitting and approvals to achieve the June 1, 2016 in-service date for each project.

We emphasize that the cost estimates provided by Con Edison, NYSEG, and NYPA for these projects were provided so that the projects could compete with the other projects that responded to the NYPA RFP. As such, the TOTS projects were proposed in a competitive environment, which we believe should have induced Con Edison, NYSEG, and NYPA to propose the most competitive price possible. We expect to retain the benefits of this competitive process for ratepayers. Therefore, Con Edison, NYSEG, and NYPA should hold their investment costs for these projects to the estimates which they supplied when the project proposals were made, and which are reported supra. The cost recovery sought for each project, as contemplated in this Order, should be limited to actual costs or to the estimates provided here, whichever is lower.

B. EE/DR/CHP Programs

In the 125 MW Revised EE/DR/CHP Program, Con Edison and NYSERDA, in consultation with NYPA, proposed a suite of new EE and DR projects designed to achieve 100 MW of peak demand reduction. They assessed these projects using a Total Resource Cost test, with adjustments, to determine the potential benefits compared to the costs.[42] The results of the test indicated that the benefits were equal to the costs, even assuming IPEC remains in service. The Revised EE/DR/CHP Program further indicated that with IPEC retired, the revised EE and DR programs would be more cost effective.

The costs of customer incentives are expected, on average, to constitute half of the revised EE and DR program costs. Con Edison and NYSERDA propose that a robust and detailed accounting would be maintained. However, the details regarding this accounting were not provided in the Revised EE/DR/CHP Program. Accordingly, we will require Con Edison to consult with NYSERDA and DPS Staff, and to develop detailed accounting procedures, reporting requirements, and an implementation plan, and to file such documents with the Secretary.

DPS Staff conducted a review of the benefit/cost analysis jointly performed by Con Edison and NYSERDA. After modifying the analysis to reflect a better forecast of the wholesale market price of energy, a year-round accounting of costs and benefits (rather than just on summer weekdays), and a more accurate estimate of the length of the programs, DPS Staff estimated that the benefits of the EE and DR programs, which were identified as part of the 125 MW Revised EE/DR/CHP Program, exceeded the costs assuming IPEC remained in service. The net resource cost savings were estimated to be approximately $182

[42] The test was set forth using the following formula:

$$\frac{\text{Benefit}}{\text{Cost}} = \frac{\text{NPV}(\text{Energy} + \text{LineLoss} + \text{Capacity} + \text{Environmental} + \text{T} + \text{D})}{\text{NPV}(\text{UtilityCosts} + \text{CustomerCosts} + \text{ProgramAdmin})}$$

We note that the “customer costs” in the above formula are not paid by utility ratepayer funds, but rather by customers’ own funds.

million over 15 years.[43] The estimated net resource cost savings were greater assuming IPEC is retired.

DPS Staff therefore recommends that these EE and DR programs be included in the IPEC Reliability Contingency Plan. We agree with DPS Staff that these EE and DR programs are worthwhile pursuing, given our expectation that the benefits of these projects will exceed the costs. Accordingly, we accept the EE and DR components (totaling 100 MW) of the 125 MW Revised EE/DR/CHP Program, as proposed by Con Edison and NYSERDA.

We disagree with parties that suggest the proposed EE and DR resources should be compared to the cost of the transmission and generation resources that were submitted for consideration as replacement resources for IPEC. Based on the cost effectiveness of the proposed EE and DR programs, such a comparison is unnecessary. These programs are reasonable to pursue, regardless of whether IPEC is retired.

An important consideration for some parties is the extent to which the EE and DR program’s peak demand reduction efforts would be coordinated with NYSERDA and Con Edison’s regular EE programs. We are persuaded that the programs will be appropriately coordinated. Moreover, the proposal has the characteristic that the incentives and program rules of the commercial and industrial programs will be uniform for both the Commission’s Energy Efficiency Portfolio Standard (EEPS) kWh incentives and the incentives for the EE and DR programs which we are considering here. Other elements of these EE and DR programs, such as thermal energy storage and battery arrays, are new programs that will not affect existing EEPS programs.

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[43] The benefits of the EE and DR programs identified in the Revised EE/DR/CHP Program exceeded the costs, even with the environmental components removed. Thus, the $182 million estimate would be even higher if the environmental components were included.

Entergy asserts that reliance on EE is a major deviation from reliability system planning that could threaten system reliability if the energy efficiency program does not achieve its projected gains. We agree that reliance on EE and DR programs is relatively new. Energy efficiency, however, is not so new as to be untested. New York and several other states have accumulated significant experience with EE over the last 20 years. In fact, EE results are routinely used in the NYISO planning process as load modifiers. We are confident that EE is a proven resource that can be relied upon for many purposes, including the one at hand – ensuring reliability in the event IPEC is retired.

Many other details have been suggested by commenters, including combining EE with renewable generation at a customer location, aggregation of small thermal storage projects, and providing extra incentives for “Made in New York” solutions. Our primary goal here, however, is to obtain the peak MW reductions needed by 2016 to help protect against reliability violations which could stem from the retirement of the IPEC. We will therefore accept the proposal, as put forward by Con Edison, NYSERDA, and NYPA, without further imposing specific requirements such as these.

We recognize that the EE and DR programs would be jointly implemented by Con Edison and NYSERDA, and we seek to ensure appropriate coordination between the two entities. The proposal to maintain a “single point of customer entry” should assist in eliminating duplicative procedures and confusion for customers. We anticipate that Con Edison and NYSERDA will develop appropriate agreements to facilitate the provision of any necessary customer information and program funds from Con

Edison to NYSERDA.[44] To the extent such agreements cannot be reached after consultation with DPS Staff, a petition should be filed with the Commission for resolution.

We also find that NYSERDA's Expanded CHP Program should be pursued to obtain 25 MW, which is in addition to the 30 MW that NYSERDA estimates will be achieved in Con Edison's service territory by June 2016 under the CHP Program already approved by the Commission. We recognize that promoting CHP resources has broad and deep support among environmental, governmental, and business interests. We find that committing further funding toward CHP projects will help to advance the Commission's objective of promoting CHP, and to reduce the reliability needs identified in the NYISO's September 18, 2012 RNA. We also concur with the parties that believe that DR and CHP should, in combination, form a substantial component of the resources that are developed as part of the response to the potential retirement of IPEC. To ensure proper accounting and reporting of the CHP aspects of the Revised EE/DR/CHP Program, Con Edison and NYSERDA should develop detailed accounting procedures, reporting requirements and an implementation plan, as we are requiring with respect to the EE and DR programs.

Finally, we acknowledge NYPA's Build Smart NY Program, and will count NYPA's 15 MW target toward the identified reliability needs under the IPEC Reliability Contingency Plan. However, because this program will be funded through NYPA low cost financing that is recovered from the direct program participants, we do not need to approve the program or the

[44] Con Edison shall establish by agreement with NYSERDA, procedures for the transfer of funds to NYSERDA to repay NYSERDA for the costs it incurs in implementing the portion of the Revised EE/DR/CHP Program for which NYSERAD has responsibility. The form of this agreement, and of any amendments to this agreement, shall be filed with the Secretary as a compliance filing.

associated funding. We expect that NYPA will update the Commission in the event that changed circumstances affect the achievement of the target amount within the necessary time frame.

In this Order, we accept the 125 MW EE/DR/CHP program set forth by Con Edison, NYSERDA and NYPA, and we take account of approximately 60 MW of peak demand reduction which these parties expect to achieve from existing programs. We recognize these are modest goals for programs of this type. We believe there continues to be unrecognized, cost-effective opportunities for EE, DR, and CHP programs to meet a greater portion of the reliability needs which the IPEC Reliability Contingency Plan describes. We direct Con Edison, working with DPS Staff, NYPA, and NYSERDA, to intensify its efforts to identify and exploit these additional opportunities, and direct Con Edison to report on these efforts by February 15, 2014.

Cost Allocation

As noted above, DPS Staff, at our direction, prepared and filed a proposed methodology for allocating and recovering costs associated with the IPEC Reliability Contingency Plan, which was the subject of two technical conferences and various comments. In general, the DPS Staff’s June Straw Proposal recommended that the same cost allocation methodology should be used for each element of the IPEC Reliability Contingency Plan portfolio. In this Order, and as discussed below, we are sensitive to the particular characteristics of the various elements of the portfolio, and we do not conclude that the same cost allocation methodologies should be used for all portfolio elements. Instead, we prefer to tailor the cost allocation solutions in a more granular way so that each specific portfolio element uses the methodology that best suits its particular characteristics.

A. TOTS Projects

In conjunction with their proposal for the TOTS projects, Con Edison and NYPA, along with the other NYTOs, have urged that DPS Staff's June Straw Proposal methodology should not be used to allocate the costs associated with implementing those projects. Instead, Con Edison and NYPA urge that the TOTS costs should be allocated in proportion to the shares already agreed to by the NYTOs in the context of preparing their NY Transco proposal.[45] As noted above, Con Edison, NYPA and the other NY Transco participants have jointly identified 18 transmission projects throughout the State which, if approved, could be undertaken to improve the State's transmission system. The three TOTS projects were among those identified by the proponents of the NY Transco.

In response to the NYTOs' cost allocation proposal, various commenters argued that cost allocation should be based solely upon a reliability beneficiaries pay methodology and should be consistent with the NYISO approach for reliability solutions. Some commenters were specifically critical of the NY Transco approach based upon their belief that the benefits of the three TOTS projects will accrue to Southeastern New York alone, and, at the same time, will bring higher energy costs and emissions to Upstate New York. Commenters also argued that the derivation of the NY Transco method has not been explained, and

[45] The NYTOs have agreed to a NY Transco cost allocation as follows: 5.4% for Central Hudson Gas & Electric Corp. (CHG&E), 38.3% for Con Edison, 16.7% for Long Island Power Authority (LIPA), 10.4% for Niagara Mohawk d.b.a. Nation Grid, 5.8% for New York State Electric & Gas (NYSEG), 3.4% for Orange & Rockland Utilities (O&R), 16.9% for NYPA, and 3.1% for Rochester Gas & Electric Corp. (RG&E). See, NYTO comments, dated July 22, 2013.

that its sponsors have not demonstrated that the method aligns allocated costs with benefits. Further, concerns were raised that the NY Transco method will lead to inconsistencies between TOTS solutions and non-TOTS solutions, thereby resulting in an unlevel playing field and divergence from the NYISO reliability cost allocation approach. Others contended that the NY Transco cost allocation method was previously rejected by the Commission in the April 2013 Order. Finally, some commenters urged that the public policy that is needed to define and sanction the benefits claimed for the TOTS projects has not been developed and that this proceeding was not intended as the forum in which this policy should be developed.

While we understand the commenters’ concerns regarding the potential for different cost allocation methods for different solutions, we recognize several factors which weigh in favor of utilizing the proposed NY Transco approach for the three TOTS projects. Specifically, the NY Transco allocation was voluntarily developed and approved by all of the NYTOs. We acknowledge that the NYTOs have achieved a significant milestone in reaching this consensus, as they have solved a problem that can hinder the construction of infrastructure across utility service territories. In this instance, however, that barrier has been surmounted. In addition, based upon the IPEC Reliability Contingency Plan analysis, the three proposed TOTS projects were found to provide net benefits both with and without IPEC in service. We also recognize that the benefits from resource adequacy solutions for the replacement of the IPEC, such as the TOTS, do not accrue solely to downstate consumers. Rather, we agree with the NYTOs that these solutions should also provide some reliability benefits statewide. Based on these factors, we find the proposed allocation of costs and benefits to be reasonable, and support the use of the proposed NY Transco cost allocation methodology.

Finally, we note that the proposed NY Transco approach, which provides that a share of the project costs will be assumed by LIPA and NYPA, achieves a broader distribution of project costs than have been achieveable in the past. In this regard, it is significant that LIPA has already indicated its agreement with the NY Transco approach.[46] For this reason, it appears unlikely that a jurisdictional challenge from LIPA will be made.

B. EE/DR/CHP Programs

DPS Staff's June Straw Proposal was silent on cost allocation for EE, DR, and CHP projects. However, the EE/DR/CHP submissions by Con Edison and NYPA urge that the costs of these programs should be allocated to Con Edison's ratepayers, just as the costs of similar utility EE, DR, or CHP programs have been allocated in the past. No commenters raised specific opposition to Con Edison's proposal. While some commenters favored a single cost allocation approach for all solutions, some favored Con Edison's cost allocation proposal for these programs. NYC stated that cost allocation of EE/DR/CHP projects need not be the same as that afforded to generation and transmission projects. Rather, NYC contends that the "benefits associated with EE/DR/CHP projects are so specific to the utility service territory in which they are located that costs associated with those measures should not be spread to other utilities."[47]

Con Edison will have the ability to target its EE/DR program to help relieve its local distribution system, thereby

[46] NYTO comments on behalf of the NY Transco with respect the IPEC Reliability Contingency Plan, p.9 (filed July 22, 2013)(indicating LIPA's willingness to accept a proposed cost allocation of 16.7%).

[47] Initial comments of NYC at page 7.

deriving specific local benefits. The Revised EE/DR/CHP Program will also provide specific and direct benefits to Con Edison customers in the form of reduced obligations to procure resource capacity.

We agree that, as recommended by Con Edison and supported by NYC and other commenters, the proposed cost allocation treatment, as submitted by Con Edison and NYSERDA, should be adopted. Accordingly, we determine that all of the costs for the Revised EE/DR/CHP Programs implemented by Con Edison and NYSERDA, as discussed herein, should be allocated to Con Edison customers, as proposed in the 125 MW Revised EE/DR/CHP Program. The costs allocated hereunder are referred to as the "Energy Efficiency/Demand Reduction/Combined Heat and Power Program Costs."

Cost Recovery

A. TOTS Projects

For TOTS projects, DPS Staff proposed that cost recovery be provided through rate base treatment of the transmission plant in the rate case of the TO building the project. Through that process, the developer TO would place the plant in service and then earn a return on and of its investment. DPS Staff initially proposed that the revenue requirement associated with the plant would be offset by payments from other beneficiary utilities over a term of 15-years (to match the term of the generation Power Purchase Agreement (PPA) in the RFP). Based on verbal comments received during its first technical conference, DPS Staff subsequently proposed that the payments would continue until the original book cost of the project was fully depreciated. DPS Staff further offered that, as an alternative to this proposal, a final “exit payment” could be made by the beneficiary utility to the TO in a manner that does not increase costs to ratepayers.

Once costs are allocated to the other beneficiary utilities, DPS Staff proposed that the allocation of costs to service classes within each utility shall be conducted in the same manner as other transmission capital and operating costs. Once allocated to the service class, DPS Staff proposed that the cost be recovered through class specific volumetric (kWh) and demand (kW) surcharges.

The NYTOs, however, disagree with DPS Staff’s proposed approach and claim that the use of the NYISO tariff to allocate and recover transmission costs is more efficient. The NYTOs argue that the NY Transco charge will be recovered from retail ratepayers in a manner that resembles the current way investor owned NYTOs recover other NYISO charges, such as NYISO Rate Schedule 1 and the NYPA Transmission Adjustment Charge. The NYTOs further contend that their method provides greater certainty and transparency than the June Straw Proposal.

We commend DPS Staff’s significant efforts in developing the June Straw Proposal. However, for the reasons discussed above, and for purposes of cost recovery for the TOTS projects, we support the NYTOs’ proposed cost allocation/recovery approach for these projects. We expect the NYTOs will file an allocation and recovery mechanism which reflects their allocation/recovery approach for review and approval by FERC. We also expect that this application will seek recovery of the initial planning costs, up to $10 million, authorized in the April 2013 Order, and other related costs in developing the IPEC Reliability Contingency Plan.

B. EE/DR/CHP Programs

As discussed above, the 125 MW Revised EE/DR/CHP Program costs will be allocated to Con Edison. Con Edison and

NYSERDA proposed that Con Edison delivery customers pay a surcharge to cover the cost of these projects, after those costs have been incurred, through the Monthly Adjustment Clause (MAC) charge, as is done for its Targeted Demand Side Management Program and other demand response programs, exclusive of NYPA's governmental customers who receive delivery service under the Company's PSC No. 12 - Electricity.[48] Con Edison and NYSERDA estimate that the cost of the Revised EE/DR/CHP Program will be approximately $285 million. While some of these costs, such as portions of the costs associated with measurement and verification and with reporting will be incurred after implementation of the employed program measures, it is reasonable to expect that the majority of the 125 MW Revised EE/DR/CHP Program costs will be incurred from 2014 through 2016. The resulting cost impact in a given year, depending on the timing of the cost incurrence, could be as high as $100 million for Con Edison's delivery customers.

To better match the time when costs of the 125 MW Revised EE/DR/CHP Program are incurred with the time when its benefits will occur, DPS Staff recommends that the costs be amortized over a ten year period. This approach would also mitigate the potential rate increases associated with recovering the costs on an as-incurred basis. We are mindful of the immediate rate impacts associated with the many initiatives that are before us, both in this proceeding and in other on-going proceedings. Accordingly, we authorize Con Edison to amortize the cost of the 125 MW Revised EE/DR/CHP Program over ten years in order to mitigate its immediate rate impacts.

The MAC is used to collect various costs from all of Con Edison's delivery customers. Its use, as proposed here for a similar purpose, is appropriate and therefore adopted. To

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[48] See, Revised EE/DR/CHP Program, pp. 20-21.

implement this directive, Con Edison shall file the requisite tariff leaves to allow for cost recovery of the 125 MW Revised EE/DR/CHP Program. In addition, however, we may revisit this cost recovery and amortization period when making final decisions in other proceedings that have an impact on rates, with the goal of minimizing the overall customer impacts.

State Environmental Quality Review Act

Earlier in this proceeding, the Commission considered its obligations under the State Environmental Quality Review Act (SEQRA) and directed DPS Staff to prepare a Generic Environmental Impact Statement (GEIS). Notice of our Determination of Significance was issued on May 21, 2013. DPS Staff subsequently developed a Draft GEIS, which we accepted as complete by Order issued July 18, 2013.[49] As required by SEQRA, a Notice of Completion of the Draft GEIS was published in the Environmental Notice Bulletin (ENB) on July 24, 2013, and comments were accepted until the close of business on August 23, 2013.

Two sets of comments were received through the public comment process. The Final GEIS summarizes all of the substantive comments and reflects revisions made in response to them. Specifically, the following substantive changes were made to the Draft GEIS following the review of the comments:

1. Descriptions of the US Power Generating Company’s generation projects were clarified in Section 2.4.1.3 (Proposed Electricity Generation Projects).

[49] Case 12-E-0503, Generation Retirement Contingency Plans, Order Adopting and Approving Issuance of a Draft Environmental Impact Statement (issued July 18, 2013).

2. Disclosure that the FERC has approved a new local capacity zone covering NYISO Zones G-J was added to Section 4.15.6 (Electric Rates).
3. Discussion of the New York State Energy Plan was added as Section 4.11.4.
4. New subsections were added (Sections 4.11.5 and 5.4.13) to address the impacts of power outages on customers with special needs.
5. A new section in Chapter 6, Cumulative Impacts, was added to specifically address the potential overlap between Energy Highway projects and the IPEC Contingency Plan components.
6. The list of required generalized permits and approvals in Table 7-1 was expanded.

We then determined that the Final GEIS presented a complete and comprehensive assessment of the significant adverse environmental impacts, as well as the benefits, that could arise with the implementation of the IPEC Reliability Contingency Plan; that it conformed to the requirements of SEQRA; and that it adequately responded to all the substantive comments provided on the Draft GEIS. Therefore, on September 19, 2013, we accepted it as the Final GEIS for the proposed adoption of an IPEC Reliability Contingency Plan and directed that the Notice of Completion of the Final GEIS be published in the ENB in accordance with 6 NYCRR Part 617.[50]

The Final GEIS describes the possible environmental impacts associated with the proposed action that includes acceptance of the IPEC Reliability Contingency Plan. The Final GEIS study shows that construction and operation of the projects contemplated in the Contingency Plan may have impacts on environmental resources in New York. The resources that may be

[50] Notice was published in the ENB on September 25, 2013.

affected, depending on the ultimate design of the projects and the construction methods employed, could include land use patterns, water resources, plants and animals, agricultural resources, aesthetic resources, historic and archaeological resources, open space and recreation, critical environmental areas, air quality, transportation, energy, noise and odor, public health, community character, and socioeconomics. The exact extent of these impacts is not quantifiable due to: (1) the complexity of the multiple factors affecting electric system operations in New York; (2) the interaction of New York's power grid with those of other states; (3) the timing of and types of possible market responses; and, (4) the geographically distributed nature of the portfolio of transmission and generation projects included in the IPEC Reliability Contingency Plan, and the likelihood that future regulatory actions will impact the final layout and design of those facilities.

However, the Final GEIS allows us to evaluate the environmental impacts of the proposed action in the context of the conditions that are likely to exist if we did not provide for a Reliability Contingency Plan. By ensuring the reliable delivery of electricity in the event that the IPEC is retired, the IPEC Reliability Contingency Plan minimizes the economic, social, and environmental effects which could result from the loss of that particular source of supply.

We further find that, even if the IPEC remains available, the Final GEIS demonstrates that the likely environmental impacts of implementing the IPEC Reliability Contingency Plan are the typical impacts associated with generation and transmission facilities, and that well-accepted mitigation techniques may be utilized in the design and construction processes to minimize their effects.

We note that these new projects may be subject to site-specific licensing and permitting requirements, and that individualized environmental assessments would be conducted in those other proceedings.[51]

On the basis of the foregoing, and the discussion set forth in the Final GEIS, we make the findings stated above regarding the environmental impacts of the proposed action and certify that:

(1) the requirements of the State Environmental Quality Review Act, as implemented by 6 NYCRR Part 617, have been met;

(2) consistent with social, economic, and other essential considerations, from among the reasonable alternatives available, the action being undertaken is one that avoids or minimizes adverse environmental impacts to the maximum extent practicable, and that adverse environmental impacts will be avoided or minimized to the maximum extent practicable by incorporating as conditions to the decision those mitigative measures that were identified as practicable; and

(3) as applicable to the coastal area, the action being undertaken is consistent with applicable policies set forth in 19 NYCRR §600.5, regarding development, fish and wildlife, agricultural lands, scenic quality, public access, recreation, flooding and erosion hazards, and water resources.

[51] Specifically, the details of the Ramapo/Rock Tavern project, for which this Commission previously issued an Article VII certificate, will receive scrutiny in DPS Staff’s review of Con Edison’s Environmental Management and Construction Plan (EM&CP). The Marcy/Fraser project will also be evaluated by DPS Staff upon submittal of an EM&CP for the Marcy South elements, and the reconductoring component will be subject to SEQRA review prior to construction. The Staten Island project will also undergo SEQRA review.

Requests for Rehearing

A. March 2013 Order

The March 15 Order accepted the Con Edison/NYPA February Filing as “responsive” to the November 2012 Order and “consistent with Con Edison’s responsibilities to ensure safe and adequate service.”[52] In particular, the Commission accepted Con Edison and NYPA’s determination that the reliability need was 1,350 MW, net of Con Edison’s 100 MW EE and DR program. The Commission therefore approved the proposal, subject to certain modifications, for NYPA to issue an RFP in order to solicit projects for inclusion in the IPEC Reliability Contingency Plan that could assist in meeting this reliability need.

1. IPPNY

On April 5, 2013, IPPNY sought rehearing of the Commission’s March 2013 Order on the basis that the record was deficient and the Commission lacked a rational basis to proceed. IPPNY identified various “deficiencies” in the Con Edison/NYPA February Filing, including 1) the failure to take into account the status of proposed power plants and AC and DC transmission projects; 2) the failure to provide an analysis of the extent, timing, and characteristics of the reliability needs that would arise if IPEC were retired; 3) the failure to quantify the degree to which the TOTS would address the IPEC-related resource adequacy or reactive power impacts; 4) the failure to consider any alternative projects; 5) the failure to demonstrate that the TOTS are narrowly tailored to address IPEC-specific reliability needs; and, 6) the failure to protect New York consumers from unnecessarily incurring substantial costs.

IPPNY further claimed the Commission improperly assigned NYPA the role of initially screening RFP responses for completeness and conformance with RFP requirements. IPPNY

[52] November 2012 Order, p. 3.

contends that NYPA has a conflict of interest, given its involvement in the TOTS projects, which should preclude NYPA from serving any role in the review of the RFP responses.

In addition, IPPNY asserted that the Commission improperly favored the TOTS projects by establishing different cost recovery standards for the TOTS projects compared to the RFP respondents, and failing to recognize potential market-based solutions in accordance with the FERC-approved tariff. IPPNY also maintained that allowing the TOTS projects to provide “good faith estimates,” as a basis for recovering their costs, improperly favored the TOTS over RFP respondents that were required to submit “not-to-exceed-values.”

2. <u>Entergy</u>

On April 11, 2013, Entergy also sought rehearing based on the grounds that the Commission lacked a rational basis to proceed due to deficiencies identified in the February 2013 Contingency Plan Filing. Entergy suggested that the Con Edison/NYPA February Filing must be supplemented before the Commission can proceed, and that the Commission erred in concluding that the reliability deficiency should be “further updated and refined prior to the conclusion of DPS Staff’s evaluation of RFP responses.”[53]

3. <u>Commission Determination</u>

We reject the claims by IPPNY and Entergy that the Commission lacked a rational basis to issue the March 2013 Order, which accepted the Con Edison/NYPA February Filing as responsive to our November 2013 Order, and approved Con Edison and NYPA’s plan to issue an RFP for solutions to meet the reliability planning needs. Neither party disputes the NYISO’s analysis that “identified reliability violations of transmission security and resource adequacy criteria by the summer of 2016 if

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[53] March 2013 Order, p. 12.

the IPEC units were retired at the expiration of their current licenses…."[54] The NYISO's 2012 Reliability Needs Assessment, as updated by the Con Edison/NYPA February Filing, provided a rational basis for the Commission to proceed with the issuance of an RFP. IPPNY's claimed deficiencies are summarized above and have been addressed in this Order.

With respect to the role of NYPA, we disagree that NYPA was improperly assigned the role of screening timely proposals for "completeness and conformance with the RFP requirements." As we expected, DPS Staff conducted an independent review of all RFP responses in order to verify and confirm NYPA's screening results. Because DPS Staff was expected to and, in fact, has provided an independent and unbiased verification of qualifying RFP responses, we reject IPPNY's argument that NYPA was inappropriately allowed to act in this capacity.

Finally, we find that allowing the TOTS projects to proceed and to recover limited costs in advance of determining a preferred portfolio of resources was not discriminatory, or biased in favor of the TOTS projects. Allowing the TOs to recover some preliminary planning costs for the TOTS appropriately reflects the NYTOs's statutory responsibilities to ensure safe and adequate service. Accordingly, the petitions for rehearing filed by IPPNY and Entergy with respect to the March 2013 Order are denied.

B. <u>April 2013 Order</u>

The April 2013 Order approved, subject to conditions, Con Edison, NYSEG, and NYPA's preliminary planning related to the three TOTS projects. The recovery of preliminary planning costs was approved, up to $10 million, for an initial period until the TOTS projects were analyzed further. Con Edison was

[54] March 2013 Order, p. 7.

also directed to work with NYSERDA and NYPA, and to file a revised plan to secure permanent peak reduction from incremental EE/DR and other resources. The Order also directed DPS Staff to propose a cost allocation and cost recovery mechanism for the Commission's consideration.

1. IPPNY

On May 17, 2013, IPPNY sought rehearing of the Commission's April 2013 Order, which it claimed improperly favored the TOTS projects and discriminated against RFP respondents. IPPNY claimed the Commission improperly authorized preliminary planning activities for the TOTS and the recovery of up to $10 million dollars in related costs. According to IPPNY, these actions provide the TOTS with a "head start" and a significant advantage when compared with RFP respondents. IPPNY further contended that the TOTS should be required to provide firm bids and prevented from recovering cost overruns.

2. Entergy

On May 20, 2013, Entergy filed its request for rehearing, which reiterated many of the same arguments it raised with respect to the March 2013 Order. Entergy continued to assert that the Commission could not rationally undertake any of its actions without curing the alleged "deficiencies" in the record. Entergy suggests that the Commission hold its actions "in abeyance until Con Edison and NYPA have fully identified and quantified the scope and magnitude of Indian Point-based system needs and the PSC has had an adequate opportunity to review those needs."[55]

Asserting that the Commission lacked a rational basis, Entergy also recognized that the 2012 RNA performed by the NYISO "reaffirmed that reactive power needs would also result if

[55] Entergy, p. 16.

Indian Point were required to cease operations."[56] Entergy suggested that the Commission cease reliability planning efforts in this proceeding until additional information is provided, including NYISO analyses "delineating the full nature and extent of Indian Point-related system needs...."[57]

In addition, Entergy submitted that the Commission lacked the statutory authority to allocate costs incurred by Con Edison to other utility customers in the State. Similarly, Entergy submitted that the Commission's authority prevented directing the utilities that were allocated costs from reimbursing NYPA.

3. Commission Determination

In large part, the arguments advanced on rehearing of our April 2013 Order are the same as were brought forward in the petitions for rehearing of the March 2013 Order. As noted above, we have, in considering the Petition for Rehearing for the March 2013 Order, addressed these objections and found they lack merit. We also find that our authority to ensure rates are just and reasonable necessarily entails ensuring costs are allocated appropriately. Accordingly, the petitions for rehearing filed by IPPNY and Entergy with respect to the April 2013 Order are denied.

CONCLUSION

As stated in previous orders, the potential retirement of the IPEC raises unique and significant reliability issues. These reliability issues, which could threaten the public health, safety, and welfare, are compounded by the inability of existing processes and markets to fashion a timely response. In response to this problem, and, in particular, to fashion an

[56] Entergy, p. 17.

[57] Entergy, p. 25.

appropriate response to the uncertainties associated with the potential retirement of the IPEC as early as December 2015, we sought the development of an IPEC Reliability Contingency Plan.

In this Order, we reviewed the plan developed in response to the Commission's earlier orders, and find that two components of this plan, i.e., the three Transmission Owners Transmission Solution projects and the 125 MW Revised EE/DR/CHP Program, should be accepted now and move as promptly as possible to implementation. We further find that the IPEC Reliability Contingency Plan, as proposed by Con Edison and NYPA, and as modified in this Order, and which includes these two components properly balances our reliability concerns with the costs to ratepayers, impacts on the environment, and other matters. Accordingly, we conclude that the acceptance of the IPEC Reliability Contingency Plan will support the continued provision of safe and adequate service, and is in the public interest.

Because of uncertainties in the generation market, DPS Staff recommends and we agree that no action should be taken at this time regarding the potential generation solutions identified through the NYPA RFP which was issued in furtherance of the Plan. Con Edison, in consultation with NYPA, should continue to monitor the status of projects which may enter or rejoin the generation market, and to assess whether changed circumstances would justify an expansion of the portfolio approved in this Order for the IPEC Reliability Contingency Plan.

Further, to support the implementation of the IPEC Reliability Contingency Plan, which we are accepting in this Order, this proceeding has described the methodologies that will be used for cost allocation and recovery for projects which are part of the plan. This Order concludes that these methodologies are just and reasonable and may be relied upon as the IPEC Reliability Contingency Plan is implemented.

The Commission orders:

1. The Indian Point Energy Center (IPEC) Reliability Contingency Plan (Plan), as described in the Consolidated Edison Company of New York, Inc. (Con Edison) and New York Power Authority (NYPA) February 1, 2013 Filing (Con Edison/NYPA February Filing), and as further described in the body of this Order, is an appropriate response to the potential reliability needs which could be associated with the retirement of the generation resources at IPEC, and such Plan, as modified through this Order, is accepted.

2. The portfolio currently accepted for the implementation of the IPEC Reliability Contingency Plan shall include two elements, i.e.:

a. The three Transmission Owner Transmission Solutions (TOTS) projects as described in the Con Edison/NYPA February Filing, as updated and discussed in the body of this Order; and

b. The 125 MW Revised Energy Efficiency/Demand Reduction/Combined Heat and Power (EE/DR/CHP) program, as described in the Con Edison/NYPA/New York State Energy Research and Development Authority (NYSERDA) filings, and discussed in the body of this Order.

3. Con Edison and New York State Electric and Gas Corporation (NYSEG) shall, and NYPA and NYSERDA are expected, to use their best efforts to undertake and timely complete their projects being undertaken as part of the IPEC Reliability Contingency Plan, as set forth in the body of this Order.

4. As set forth in the body of this Order, Con Edison and NYSEG, in consultation with NYPA, should proceed as quickly as possible with an application to the Federal Energy Regulatory Commission for approval for the cost allocation and cost recovery for the TOTS projects. Con Edison and NYSEG, in consultation with NYPA, shall supply a report on the progress of this cost allocation and cost recovery application on or before June 30, 2014, and every six months thereafter.

5. Con Edison is directed to file tariff amendments, to be become effective on a temporary basis on or before March 1, 2014, on not less than 30 days notice, as are consistent with the provisions of this Order and necessary to effectuate the recovery of the “Energy Efficiency/Demand Reduction/Combined Heat and Power Program Costs” that have been allocated to Con Edison in this Order. Con Edison shall serve copies of this filing on all parties to this case. Any comments on the filing must be filed within 14 days of service of such filing. The tariff amendments specified in the filing shall not become effective on a permanent basis until approved by the Commission.

6. Con Edison shall consult with NYSERDA and Department of Public Service Staff, and file detailed accounting procedures, reporting requirements, and an implementation plan regarding the Revised Energy Efficiency/Demand Reduction/Combined Heat and Power Programs with the Secretary, as discussed in the body of this Order, within 90 days of this Order. Con Edison shall serve copies of this filing on all parties to this case. Any comments on the filing must be filed within 14 days of service of such filing.

7. Con Edison shall consult with NYSERDA, NYPA, and Department of Public Service Staff, and file a report with the Secretary on the identification of additional cost-effective

opportunities for energy efficiency, demand reduction, and combined heat and power programs, as discussed in the body of this Order, by February 15, 2014.

8. The requirements of Section 66(12)(b) of the Public Service Law as to newspaper publication of the tariff amendments described in Ordering Clause No. 5 are waived.

9. The Secretary may extend the deadlines set forth in this order upon good cause shown, provided the request for such extension is in writing and filed on a timely basis, which should be on at least one day's notice.

10. The developer transmission owners for the TOTS projects identified in this order shall construct and operate the TOTS projects in compliance with any environmental impact mitigation requirements established through the site-specific environmental permitting for such projects.

11. The petitions of Independent Power Producers of New York, Inc. for rehearing are denied.

12. The petitions of Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, Entergy Nuclear Fitzpatrick, LLC, and Entergy Nuclear Operations, Inc. for rehearing are denied.

13. This proceeding is continued.

By the Commission,

Kathleen H. Burgess
Digitally Signed by Secretary
New York Public Service Commission

(SIGNED) KATHLEEN H. BURGESS
Secretary

SUMMARY OF NOTICES

1. To seek comments in this Case 12-E-0503, the Department issued four notices pursuant to the State Administrative Procedure Act (SAPA). The date of publication for these notices and a summary of the SAPAs are:

1) 2/20/2013 - The Public Service Commission (Commission) is considering portions of a filing made by Consolidated Edison Company of New York, Inc. and the New York Power Authority on February 1, 2013, concerning reliability contingency plans to address the potential retirement of the Indian Point Energy Center (Filing). The Commission is considering whether to adopt, modify, or reject, in whole or in part, the aspects of the Filing identified as items 2(a) through 2(e) on pages 3 to 4, as discussed at those pages and elsewhere in the Filing.

2) 6/5/2013 - The Public Service Commission (Commission) is considering a filing made by the Department of Public Service on June 4, 2013, concerning a proposed method for allocating and recovering the costs associated with the reliability contingency plans to address the potential retirement of the Indian Point Energy Center (Filing). The Department of Public Service also included in the Filing a proposed Reimbursement Agreement to address the costs incurred by the New York Power Authority in connection with the Indian Point Energy Center reliability contingency plans. The Commission is considering whether to adopt, modify, or reject, in whole or in part, the Filing, and may address related matters.

3) 7/3/2013 - The Public Service Commission (Commission) is considering whether to adopt, modify, or reject, in whole or in part, proposed projects for inclusion in reliability contingency plan(s) to address the potential retirement of the Indian Point Energy Center, and may address related matters. The Commission is considering various proposed projects filed in Case 12-E-0503 between February 1, 2013, and June 13, 2013, by Consolidated Edison Company of New York, Inc., New York Power Authority and New York State Electric and Gas Corporation, Poseidon Transmission LLC, West Point Partners, LLC, Iberdrola USA Management Corporation,

Boundless Energy N.E., LLC, CPV Valley, LLC, Cricket Valley Energy Center LLC, GE Energy Financial Services, NRG Energy, Inc., US Power Generating Company, NYC Energy, LLC, Entergy Nuclear Power Marketing (on behalf of Entergy Nuclear Indian Point 2 LLC, Entergy Nuclear Indian Point 3 LLC, and Entergy Nuclear Operations, Inc.), CCI Roseton LLC, Selkirk Cogen Partners, L.P., and AES Energy Storage, LLC.

4) 7/17/2013 - The Public Service Commission (Commission) is considering whether to adopt, modify, or reject, in whole or in part, proposed energy efficiency, demand reduction, and combined heat and power projects filed in Case 12-E-0503 on June 20, 2013, by Consolidated Edison Company of New York, Inc., the New York Power Authority, and the New York State Energy Research and Development Authority (Filing). The Commission may address the June 20, 2013 Filing and related matters in developing reliability contingency plan(s) to address the potential retirement of the Indian Point Energy Center.

2. In addition, the Department issued its own notices for comments and to announce two technical conferences as follows:

2/13/2013	Notices	Generation Retirement Contingency Plans, Notice Soliciting Comments
6/5/2013	Notices	Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans, Notice Soliciting Comments and of Technical Conference
6/20/2013	Notices	Generation Retirement Contingency Plans, Notice of Updated Information for Technical Conference
7/2/2013	Notices	Generation Retirement Contingency Plans, Notice of Second Technical Conference and Revised Comment Schedule

3. The Department also sought comments in connection with its draft Generic Environmental Impact Statement as follows:

7/18/2013	Notices	Generation Retirement Contingency Plans, Notice of Completion of Draft Generic Environmental Impact Statement

SUMMARY OF COMMENTS

African American Environmentalist Association:

The African American Environmentalist Association expresses support for the continued operation of IPEC.

Boilermakers Local Lodge No. 5 (Boilermakers):

The Boilermakers urge the Commission to abandon the development of a contingency plan for the retirement of the IPEC, and instead pursue needed investment in New York's energy infrastructure.

Boundless Energy NE, LLC:

Boundless Energy asserts that the NYTO proposal to cost allocate NYTO projects in the IPEC Contingency Plan in the same way as projects in the AC Transmission Proceeding (Case 12-T-0502) is premature and unfair. It suggests that inappropriate distinctions in cost allocation should not be made between NYTO projects and other transmission developers.

Business Council of New York State:

The Business Council of New York State requests that the Commission abandon its pursuit of an IPEC Reliability Contingency Plan and pursue a more deliberate, discerning approach towards planning for the retirement of New York’s electric generating units.

Business Council of Westchester:

The Business Council of Westchester expresses its opposition to burdening Westchester County and New York City ratepayers with the $811 million cost to develop projects in compliance with the Indian Point contingency plan.

Bronx Chamber of Commerce:

The Bronx Chamber of Commerce maintains that the June Straw Proposal delivers only questionable benefits for the downstate regions, while placing an undue, harmful burden on the local economy.

Brookfield Renewable Energy Group (Brookfield):

Brookfield supports the IPEC contingency planning effort, but maintains that the plan did not provide an opportunity for the market to provide solutions to meet the potential need. Brookfield is concerned that out-of-market approaches to planning have the potential to result in adverse consequences on the markets, impairing investor confidence and significantly increasing the risk profile of merchant generators that are crucial to the functioning of New York's electricity system. Overall, Brookfield believes that the State should endeavor to address identified or contingent needs within market structures wherever possible.

Central Hudson Gas & Electric (Central Hudson):

Central Hudson asks the Commission to consider other benefits in cost allocation besides reliability. It asserts that the use of the new ICAP zone (NCZ) and the indicative Locational Capacity Requirements (LCR) as the basis for the allocation of transmission solutions is a misapplication of the NCZ LCR. Central Hudson maintains the TOTS projects provide the same benefits as AC Transmission and should be cost allocated as per the NY Transco method.

Cogen Technologies Linden Venture, LP (Cogen):

Cogen agrees that it is prudent for the Commission to work with stakeholders to develop a reliability contingency plan to address issues which may arise upon the closure of the IPEC.

Cogen supports the consideration of existing resources in the contingency plan and the availability of natural gas in developing the plan.

Consolidated Edison Company of New York, Inc. (Con Edison):

In its reply to comments on the Con Edison/NYPA February Filing, Con Edison stated that: 1) it appropriately identified the impact from on-going EE and CHP activities, 2) its proposed EE/DR program does target incremental reductions to peak demand, 3) the EE/DR program will allow a clear market signal to develop that encourages peak demand reduction, 4) the proposed incentive structure is complementary to existing utility and NYSERDA EEPS programs, 5) it has evaluated likely opportunities where the market can quickly deliver peak demand reductions, 6) program costs will be collected in arrears, and will cost between $150 to $300 million. Con Edison also provided additional details regarding its proposed Cost/Benefit test.

Consolidated Edison Solutions, Inc.:

Con Edison Solutions notes that the collection of transmission costs from all Load Serving Entities through a NYISO charge would be a departure from the historical practice of having the individual transmission owner recover its transmission costs as part of its delivery service charge from all its customers, regardless of whether such customers are purchasing their electricity from the utility or a competitive supplier such as Con Edison Solutions. In addition, transmission costs are not something that competitive suppliers can hedge or readily predict. Therefore, to the extent that the Commission approves the Filing, Con Edison Solutions requests that the Commission direct the various utilities participating in these projects to work with the NYISO to provide periodic estimates of the anticipated revenue requirements and resulting transmission rates that LSEs would be charged and that customers can expect to pay.

Consumer Power Advocates (CPA):

CPA argues for a balanced approach to address any reliability needs including a strong EE/DR program, with "market pricing mechanisms for EE/DR as the best way to insure balance between demand side and supply side solutions." CPA also argues that Distributed Generation and Combined Heat and Power systems also be included in the EE/DR program.

Cricket Valley Energy Center LLC (Cricket Valley):

Cricket Valley generally supports the Con Edison/NYPA Contingency Plan, but requests revisions to the proposed in-service date making it farther out in time. Cricket Valley also suggests the Plan is biased toward the TOTS and EE/DR programs, and seeks to have generation projects compete on an equal basis.

Empire Generating Co., LLC, et al.[58]:

The New York Generators argue that FERC has exclusive jurisdiction over the interstate transmission projects and wholesale generation projects proposed in this proceeding, thereby precluding the Commission’s jurisdiction. The Straw Proposal, according to the New York Generators threatens to preclude or interfere with NYISO operations and planning process. They maintain that the Commission’s jurisdiction over cost allocation has not been established.

[58] Empire Generating Co, LLC, TC Ravenswood LLC, US Power Generating Company (parent company of Astoria Generating Company, L.P), PSEG Power New York LLC and PSEG Energy Resources and Trade LLC submitting jointly as the “New York Generators”.

Entergy Nuclear Indian Point 2, LLC, et al. (Entergy):

Entergy argues that the Con Edison/NYPA February Filing does not indicate the full nature of the reliability impacts that would be caused by an IPEC shutdown. Entergy notes that the NYISO’s 2012 RNA indicates that there would be both resource adequacy and reactive power implications if Indian Point was required to cease operations, and points out that the Filing only quantifies the resource adequacy related needs.[59]

Entergy strongly opposes adoption of the IPEC Reliability Contingency Plan. Entergy first argues that the Plan has failed to provide all the information identified in the Commission’s April 19, 2013 Order, and thus the Commission lacks basis for approving the plan. Entergy argues that insufficient system planning and analysis has been completed and in particular there is a lack of information about the extent, timing, and characteristics of system needs related to a possible IPEC closure. Entergy points out that IPEC retirement needs, as identified in the NYISO’s 2012 Reliability Needs Assessment, include resource adequacy needs, transmission security needs and reactive power considerations. It argues the Con Edison/NYPA February Filing failed to consider transmission security needs and reactive power considerations. Further, Entergy argues the Commission’s March 2013 Order (approving the RFP process) and April 19, 2013 Order (advancing transmission and EE/DR/CHP projects) were both issued irrespective of these non-resource considerations. Entergy also points out that although DPS staff confirmed at the July 15, 2013 Technical Conference that transmission security needs have been completed, no analyses were provided, including a quantification of the estimated level of transmission security violations that would occur with an IPEC retirement. Entergy points out that resource adequacy

[59] Entergy comments, February 22, 2013, p. 11.

estimates provided by DPS Staff at the Technical Conference differed from the earlier Joint Plan calculation, providing further support, Entergy argues, that the "core information" identified in the Commission's November 2012 Order (i.e. "the full extent, timing and characteristics of system needs") is lacking. Entergy concludes this point by arguing that absent this information, adoption of the EE/DR/CHP program would be arbitrary and capricious.

Entergy argues there is a lack of information regarding whether the Revised EE/DR/CHP Program, together with the TOTS projects, addresses IPEC-specific system needs. Entergy's view is that the TOTS projects and EE/DR/CHP plan do not address the full scope of the system resource adequacy, transmission security, and reactive power considerations. Entergy opines that there has been a lack of portfolio-based analysis and that the TOTS projects and EE/DR/CHP plans, as well as the earlier plan, have failed to properly assess other alternatives and whether such alternatives could be "implemented at a later time and/or at a lower cost to better protect New York consumers." Entergy concludes by reiterating its view that the Commission lacks a rational basis to approve the EE/DR/CHP plan absent a full assessment of system needs, the quantification of the proposed solutions towards the needs and an assessment of alternatives, including timing and costs.

Entergy also suggests that even if the record was sufficient, the Revised EE/DR/CHP Program requires changes. Entergy argues that the EE/DR/CHP plan should be properly evaluated within a broader competitive process. Entergy argues the EE/DR/CHP plan was erroneously separated from the RFP process required from the Commission's November 2012 Order. While the earlier Con Edison/NYPA February Filing proposed that the TOTS Projects would subsequently be compared against RFP procured projects, Entergy argues that there have not been any provisions for the EE/DR/CHP plan to be evaluated against other options. Entergy recommends that the EE/DR/CHP plan also be assessed using the “Comparative Evaluation Process” for evaluating the TOTS Projects and RFP Projects against each other.

Entergy argues that the EE/DR/CHP plan must not supplant the EEPS Program. Entergy argues that further review is required to ensure the EE/DR/CHP plan would foster, and not supplant, existing EEPS programs and why those EEPS programs have not focused on the proposed incremental savings.

Entergy argues the projected schedule of MW reductions should be further reviewed. Entergy points out that the originally filed Joint Plan presented, in Entergy’s opinion, an overly aggressive MW reduction schedule that projects the 100 MW reduction from EE/DR/CHP to be accomplished by the end of 2015. In particular, Entergy points out that the Joint Plan plans to achieve 34% of the MW savings during the first 21 months of the program with the remaining balance to be achieved during the 12 months of calendar year 2015. Entergy echoes the initial comments of New York City which opines that trends in efficient lighting programs suggest most efficiency gains from lighting come early in a program and then are increasingly difficult to attain. This, in Entergy’s view, conflicts with the projections of the Joint Plan, and Entergy recommends that the Commission, therefore, carefully scrutinize the reasonableness of the proposed MW attainment schedule.

Entergy requests that the Commission: (1) reject Section 2(e) of the Joint Plan, which finds the TOTs project meet public policy requirements, because neither the November 2012 Order, which defines the scope of this proceeding nor the EHI Task Force Blueprint, establish "public policy requirements" as defined by the NYISO in its October Compliance Filing even if the FERC ultimately accepted the NYISO's expansive definition in this regard; (2) direct Con Edison (with NYPA, to the extent deemed necessary) to expeditiously supplement the Joint Plan to provide information: (i) identifying in detail the full scope and nature of the reliability needs that would be triggered if the Indian Point facilities were required to cease operations; (ii) quantifying the degree to which each of its proposed solutions addresses each identified need; and (iii) identifying the timing and costs of other alternatives that also are viable options to address each identified need; and (3) defer any action on the Notice as it pertains to Sections2(a) through (d) of the Joint Plan until Con Edison supplements the Joint Plan.

Entergy argues that FERC has exclusive jurisdiction over rates, terms, and conditions of transmission service and wholesale generation service, and State law provides no basis for the Commission to implement the June Straw Proposal. It maintains two flawed assumptions exist in the Straw Proposal: (1) markets forces will fail to provide a solution if IPEC ceases operations; and (2) the NYISO’s reliability planning process will fail to address the problem. Entergy suggests the NYISO gap solutions are intended to solve this problem. It suggests there are no current reliability needs, and no proof that the IPEC can’t be relicensed.

Environmental Defense Fund (EDF):

EDF commends the Commission for its vision in recognizing that energy efficiency, distributed renewable generation, demand response, and combined heat-and-power represent resources that can play a critical role in meeting system needs.

Hudson Valley Gateway Chamber of Commerce:

The Hudson Valley Gateway Chamber of Commerce raises concerns with the financial impacts of the June Straw Proposal.

H.Q. Energy Services (HQ):

HQ urges the Commission to adopt a RFP process that allows developers to propose in-service dates for their respective projects later than June 2016. Allowing for alternative in-service dates, HQ asserts, will encourage more developers to participate in the RFP process, thereby driving competition, lowering project costs and increasing options to alleviate reliability concerns.

Ian Ramcharitar:

Opposes the development of the IPEC Reliability Contingency Plan because it would add a surcharge to the existing rates, which he maintains are already too high.

Ice Energy Holdings Inc. (Ice Energy):

Ice Energy, which manufactures and develops thermal (ice) storage systems, strongly supports the Contingency Plan and the inclusion of thermal energy storage systems in the Plan. Ice Energy recommends the Plan be further modified as follows; Ice Energy argues that enhanced payments be added for projects or technologies that combine energy efficiency or demand response with customer-side distributed renewable energy resources, such as photovoltaic energy. Ice Energy takes exception to footnote 8 on page 9 of the Plan where Con Edison and NYSERDA state that further discussion is needed before Renewable Portfolio Standard-eligible renewables can be included. Ice Energy argues that innovation now allow multiple technologies to be deployed in a single project and that such combined systems should be "entitled to enhanced payments to provide appropriate incentives for such clean energy transition."

Ice Energy recommends that the aggregation of smaller projects into one or more larger projects be explicitly allowed. Ice Energy notes that the Plan language may be interpreted as implicitly allowing this but they recommend that aggregation be explicitly added to the Plan. They cite the language on page 4 of the Plan, which states the incentives will include a bonus for “large projects and project aggregations by large customers”. Ice Energy also notes the statement on page 5 of the Plan which indicates Con Edison will focus its recruitment on large commercial and industrial customers. Ice Energy comments that program objectives can also be accomplished by focusing on many smaller commercial and industrial customers and aggregating small projects into larger projects that can be monitored and controlled as one project. Ice Energy states, for example, that the definition of a large project could be one customer in excess of 1MW or more peak day demand, or could alternatively be defined as an aggregation of smaller customers into 1MW or more of peak day demand. Ice Energy further states that incentives should be payable to either an eligible electric customer paying into the IPEC Reliability Surcharge or to a project developer that aggregates multiple host sites in which all of the electric customers within the aggregation would otherwise qualify for individual payments.

Ice Energy recommends extra benefits for made in New York Solutions. Ice Energy argues that solutions manufactured in New York State provide “substantial additional benefits” that merit enhanced benefit premium payments. Procuring locally sourced equipment provides benefits, in Ice Energy’s opinion, of enhancing clean energy innovation, reducing greenhouse gases used in out of state shipping, and enhancing the states struggling tax base.

Ice Energy argues that where a technology or project provides more benefits to Con Edison than to a distributed host customer, Con Edison should pay more than the proposed 50-50 cost share allocation. Ice Energy takes exception to the Plan’s “implicit” assumption, in its opinion, that customer benefits from a project will, at all times, be equal to or greater than Con Edison’s benefits. This, in Ice Energy’s view, is the basis for the footnote 6 on page 8 which states “cost share for participants represents approximately half of total project costs.” Ice Energy posits that this implicit assumption is not always true and cites an example where a customer installs a thermal storage system which allows for more efficient air conditioning operation. Ice Energy argues that in cases like these the energy savings and lower bill benefits to the customer can often be far outweighed by the benefit to the utility in terms of peak demand reduction, reduced need for transmission and distribution infrastructure, and environmental benefits from less fossil fuel consumption for required peaking generation. Ice Energy concludes that Con Edison would be a “free rider” in these cases and that the proposed 50/50 sharing in these cases would lead to the project being non-cost-effective from the customer side, potentially killing such projects. Ice Energy recommends, therefore, that incentive payments are allowed to be graduated to increase customer payments in cases where the utility benefits more than the customer.

Ice Energy further argues that renewable energy should be included. Ice Energy reiterates that the peak day demand reduction benefits of renewable energy technology is well proven and should be included in the Plan, and that this should be done without the need for exhaustive study or further delay.

Independent Power Producers of New York, Inc. (IPPNY):

IPPNY, similar to Entergy, also argues that the Con Edison/NYPA February Filing fails to indicate the full nature of the reliability impacts that would be caused by an IPEC shutdown. IPPNY further states that Con Edison’s proposal does not give market-based solutions an opportunity to respond to the IPEC reliability deficiency need. IPPNY contends that the IPEC

Contingency Plan harms the competitive market and it is substantively deficient.

Jan Mayer:

Opposes the development of the IPEC Reliability Contingency Plan, which she contends will increase rates and have no benefits.

Long Island Power Authority (LIPA):

LIPA notes the Commission’s limited jurisdiction over LIPA. LIPA asserts DPS Staff’s Straw Proposal has various differences from the NYISO’s reliability cost allocation approach and does not address the beneficiaries pay principle.

Mary Ellen Furlong:

Ms. Furlong questions the timing of the IPEC Reliability Contingency Plan, which she characterizes as an attempt to “sneak” a ratepayer fee.

Matthew Fiorillo:

Mr. Fiorillo opposes the IPEC Reliability Contingency Plan and the June Straw Proposal as an unnecessary increase in electric rates.

Multiple Intervenors (MI):

MI argues that the Con Edison/NYPA February Filing fails to include an analysis, for planning purposes, of the extent, timing, and characteristics of the reliability needs that would arise if Indian Point Units 2 and 3 were retired, as required by the November 2012 Order. MI requests that the Commission reject the contingency plan submitted by Con Edison and NYPA as deficient. Additionally, if and when cost allocation issues are ripe for resolution in this proceeding, MI asks the Commission to adhere to the same “beneficiaries pay” principles that it has enumerated and followed very recently when confronted with the exact same issue (i.e., the incurrence of costs to solve a potential reliability problem created by the proposed closure of a generation facility).

MI focused its reply comments on Staff's June Straw Proposal, arguing first that the Commission should refrain from the unnecessary imposition of exorbitant costs on retail electricity customers, especially based on the incomplete record in this proceeding. MI argues that the purported contributions of individual projects such as the TOTS, and presumably (but not explicitly stated) the energy efficiency plan, are "not clear and unproven." Secondly, MI argues that the NYTOs' arguments opposing the Commission's prior approval of "a reliability beneficiaries pay" cost allocation methodology should be rejected. In a point related to this, MI states the IPEC reliability proceeding falls short of the requirements of FERC Order No. 1000 on Transmission Planning and Cost Allocation, which directs that transmission planning and cost allocation initiatives be "broadly considered through legislative process or a broadly considered comprehensive regulated process." MI concludes that the Commission's possible approval of the TOTS projects or EE/DR/CHP plan is not being completed in response to a broad considered public process, but rather is being contemplated by a narrower desire to maintain reliability in the face of the possible closure of IPEC.

MI argues that the Commission should not approve the TOTS projects, but instead evaluate them thoroughly along with any RFP submitted projects. MI also continues to argue for the "beneficiaries pay" allocation policy. It also reiterates its initial comments that there was "inadequate justification for the proposed, substantial expenditures on energy efficiency ("EE") and demand response ("DR")."

MI argues against the NY Transco approach on the basis that: (a) the NY Transco concept has yet to be justified and does not yet exist; (b) it is unclear if NYPA or LIPA can participate in the NY Transco; (c) contrary to statements that NY Transco will be a public/private partnership, it appears to exclude any material private investment, thereby being funded primarily through ratepayers; (d) NY Transco has not been shown to be in the public interest; and, (e) the Commission has not approved the NY Transco concept. Therefore, MI posits that no basis exists to adopt the NY Transco cost allocation method.

MI argues the NY Transco cost allocation methodology in inconsistent with the Commission's prior ruling that allocation should be based upon reliability beneficiaries pay. The NY Transco cost allocation method, according to MI, is highly inequitable to Upstate NY customers as they are not beneficiaries of the IPEC Contingency Plan. It notes the Commission has allocated costs of Upstate NY generator closings to Upstate NY customers without considering allocating any costs to Downstate. It also suggests that benefits, other than reliability, are irrelevant to cost allocation given that the IPEC Contingency Plan was undertaken to address reliability concerns, and the Commission ruled that costs in this proceeding should be based on reliability beneficiaries pay. MI argues this proceeding is specifically limited to the potential closing of the IPEC, and as such is not invoking any statewide public policy, thereby making the argument that TOTS projects provide public policy benefits specious when no federal or State law or regulation or order has defined or sanctioned that public policy.

Municipal Electric Utilities Association (MEUA):

MEUA argues that the Commission should retain a beneficiaries pay model, such as the DPS June Straw Proposal. MEUA contends the NY Transco allocation directly violates the

April 2013 Order, which indicated that cost allocation should adhere to a beneficiaries pay principle. It also argues that NY Transco claims of benefits are unsupported on the record. Derivation of the NY Transco cost allocation method has not been explained. Further, MEUA asserts that the NYTOs have not demonstrated that the NY Transco cost allocation satisfies FERC’s cost allocation requirements.

Natural Resource Defense Council and Pace Energy and Climate Center (NRDC):

NRDC asserts that this proceeding presents an opportunity for the State to set an example for the nation on how to responsibly confront the potential retirement of baseload generation in a manner that maintains reliability through an innovative portfolio of diverse resources—including a robust suite of investments in targeted energy efficiency, renewables, clean distributed generation, such as CHP, and demand response. NRDC is concerned that the Con Edison/NYPA February Filing relies primarily on the 20th century model of large central generation and upgrades to transmission infrastructure. NRDC argues that while these conventional resources will likely be a component of the final contingency plan, they should only be considered after all cost-effective energy efficiency, distributed and other renewable generation, CHP and demand response is achieved.

New York Affordable Reliable Electricity Alliance:

The New York Affordable Reliable Electricity Alliance opposes the June Straw Proposal cost allocation. It maintains that the continued operation of the IPEC makes good sense for the State's energy supply and economy.

New York Battery and Energy Storage Technology Consortium, Inc. (NY-BEST):

NY-BEST comments that distributed energy storage systems should be part of Con Ed's planned 100MW of Energy Efficiency/Demand Reduction/CHP. NY-BEST opines that distributed energy storage solutions are becoming commercially available, and offer the potential benefits of better balancing of transmission and distribution resources and deeper penetration of renewable resources. NY-BEST also points out that the generally smaller size of distributed storage systems compared to traditional generation and transmission and distribution solutions, and the ability to aggregate storage systems, offer advantages of easier and quicker deployment that can "substantially contribute to reducing demand reduction by 100 MW by the summer of 2015 in the Con Edison territory."

New York City Hispanic Chamber of Commerce, Inc.:

The NYC Hispanic Chamber of Commerce expresses deep concern and opposition with the proposal to require Con Edison to spend nearly $1 billion of ratepayer money to find a replacement for the IPEC.

New York City Office of Long-Term Planning and Sustainability (NYC):

NYC argues that the Con Edison/NYPA February Filing does not indicate the full nature of the reliability impacts that would be caused by an IPEC shutdown. NYC also comments on Con Edison's filing pertaining to its analysis of the reliability needs that would arise from an IPEC shutdown stating that the "discussion is provided but limited to the reference to the NYISO 2012 Reliability Needs Assessment."[60] NYC claims that Con Edison's Plan does not include an "identification and assessment

[60] NYC comments, February 22, 2013, p. 13.

of the generation, transmission, and other resources."[61] NYC also contends that there is no need for the Commission to burden the State's ratepayers with hundreds of millions, or billions, of dollars of unnecessary costs on generation and transmission facilities that will not be needed in 2016.

With respect to EE/DR/CHP, NYC argues that the Commission should not apply the cost allocation methodology set forth in Staff's Straw Proposal to EE/DR/CHP projects. The City argues that EE/DR/CHP benefits projects are specific to the utility service territory in which they are located and that costs associated with those measures should not be spread to other utilities.

NYC argues that the Commission should not approve the Con Edison/NYPA February Filing. Instead, NYC recommends the following changes to the EE/DR program proposed in the contingency plan: 1) "before authorizing any expenditure of ratepayer funds, the PSC should direct Con Edison to engage in the preliminary fact-finding and analysis necessary to prove both the reasonableness of its proposals and that the load/demand reductions can actually be achieved;" 2) "if energy efficiency and demand response are to be part of the replacement for the output of IPEC, the most logical and appropriate approach would be to expand or increase funding for the [Energy Efficiency Portfolio Standard] programs, and to target such programs to affected downstate areas;" 3) "the PSC should not allow Con Edison to spend more on energy efficiency or other load reductions than it would cost to replace the capacity of IPEC;" 4) the "PSC [should] treat the [EE/DR] expense as a shareholder-provided capital investment for which its shareholders would receive the same rate of return applicable to its actual capital investments; 5) Should the PSC decide that

[61] MI comments, February 22, 2013, p. 6; NYC comments, February 22, 2013, p. 13.

Con Edison should proceed with the EE/DR program, "the City recommends that the Company’s effort be focused on supporting and incentivizing distributed generation (“DG”) projects throughout the City that could be completed by 2016 and that would, with greater likelihood, result in large-scale peak load reductions;" and, 6) Con Ed should continue to use the TRC test. In the City's words, "Given the higher costs of the proposed program, the use of less demanding standards to measure cost-effectiveness is inappropriate and should not be adopted."

NYC argues that FERC has exclusive jurisdiction over interstate transmission service, including the TOTS. It also asserts that no studies have been performed to indicate Zones G-J are the only beneficiaries of the IPEC Reliability Contingency Plan. It notes the DPS Staff June Straw Proposal does not allocate costs to municipalities or cooperatives. However, NYC suggests that the EE/DR/CHP programs are locational specific, are moving separately in this proceeding and do not compete with generation or transmission, and is therefore fair to allocate the costs of EE/DR/CHP to Con Edison’s service territory.

NYC also argues the Commission lacks jurisdiction over NYPA to recover NYPA costs incurred. NYC suggests that NYPA can procure new capacity on behalf of NYC only with NYC’s express consent.

New York Energy Consumers Council, Inc.:

The New York Energy Consumers Council hopes the Commission will act responsibly and refuse to order the expenditure of any unnecessary ratepayer funds while the closure of Indian Point remains inconclusive.

New York State Assemblyman Alfred Graf:

Assemblyman Graf is concerned about the potential cost-shifting to the already beleaguered ratepayers on Long Island as the New York Power Authority, with Con Edison move forward with

New York State Assemblyman McDonough:

Assemblyman McDonough expresses strong concerns with potential cost-shifting to Long Island.

New York State Assemblyman Joseph D. Morelle:

Assemblyman Morelle is concerned with the pace of this proceeding, and that ratepayers in one region of the State may wind up subsidizing ratepayers in another region of the State. He is also concerned about the effects of a rate increase on business, families, and the economy.

New York State Assemblyman William A. Barclay:

Assemblyman Barclay conveys his strong concerns regarding the implementation of the Indian Point Contingency Plan and the cost that such a plan will have on New York ratepayers.

New York State Assemblyman Andrew R. Garbarino:

Assemblyman Garbarino has concerns with potential cost-shifting to Long Island ratepayers as part of the IPEC Reliability Contingency Plan.

New York State Department of Environmental Conservation (DEC):

DEC requests that the Commission give priority to environmentally beneficial projects such as renewable energy and repowering existing generation facilities. DEC also seeks to ensure adequate consideration of environmental factors.

New York State Energy Research and Development Authority (NYSERDA):

NYSERDA comments on the Con Edison/NYPA February Filing state that the proposed EE and DR programs include technology options and customer eligibility parameters that are inappropriately narrow while the proposed budget and ratepayer collections appear inappropriately expansive. While NYSERDA believes the 100 MW target is reasonable, it suggests options and opportunities to deliver 100 MW of EE and Load Management (LM) load reduction.

New York State Senator David Carlucci:

Senator Carlucci asserts that due to the uncertainty over the continued operation of Indian Point Energy Center, a comprehensive plan must be developed in the event the facility is retired.

New York State Senator George D. Maziarz:

Senator Maziarz expresses concern regarding the potential cost implications to ratepayer from the implementation of the IPEC Reliability Contingency Plan. In his view, these costs should not be allocated to Upstate ratepayers but should be focused on consumers in Westchester and New York City. He expresses additional concerns about the possibility that assets or resources of NYPA, which are created through the NYPA hydroelectric facilities in Western New York, will be directed to IPEC Reliability Contingency Plan investments, which are located in southeastern New York and which are unlikely to provide benefits to Western New York customers. Finally, Senator Maziarz objects to the magnitude of the costs of the facilities which could be a part of the Plan's portfolio, and especially where the recovery of some or all of these costs will require rate increases for NYPA customers. Senator Maziarz concludes by recommending that the investments approved in the Plan should be directed toward the construction of new transmission facilities so that power can more easily flow from Upstate and Western New York power plants to New York City customers.

New York State Senator Kevin S. Parker:

Senator Parker raises concerns regarding the proposal to require Con Edison ratepayers (along with other New York distribution utilities), to spend nearly $1 billion to find a replacement for the IPEC.

New York State Senator Mark Grisanti:

Senator Grisanti urges the Commission to consider the cost implications to the ratepayers of Upstate New York associated with the development and implementation of the IPEC Reliability Contingency Plan.

New York State Senator Ted O'Brien:

Senator O'Brien urges the Commission to consider the cost implications to Upstate New York ratepayers.

New York State Senator Timothy M. Kennedy:

Senator Kennedy argues that the contingency plan developed by Con Edison and the NYPA will burden ratepayers in Upstate New York with subsidizing projects that will solely benefit downstate customers.

New York Transmission Owners (on behalf of NY Transco):

The NYTOs argue that all NY Transco projects (with TOTS being a part) provide significant statewide benefits. The NYTOs maintain there are various benefits in the aggregate of all NY Transco projects in terms of added jobs, tax revenues, economic growth, emissions, energy market efficiency and reliability. The NY Transco adjusted load ratio share cost allocation, they maintain, accounts for all benefits that may accrue upstate and downstate. The adjusted load ratio share Transco cost allocation assumes 75% of befits accrue Downstate versus 60% for a straight load ratio share. The NYTOs argue that the same cost allocation for transmission, generation, and DR does not accommodate different benefits because each (or at least transmission versus generation/DR) impact the system in different ways.

The NYTOs urge the Commission to endorse the NY Transco cost recovery proposal. NY Transco cost recovery method via the NYISO Tariff will apply to all loads and will obviate the need for contracts; and therefore will be more efficient and less problematic administratively than the DPS Straw Proposal to recover transmission costs. Irrespective of the methods chosen, the NYTOs request that the Commission ensure full cost recovery.

NRG Energy, Inc. (NRG):

NRG states in its comments that it “understands that the New York Independent System Operator’s 2012 Reliability Needs Assessment concluded that violations of transmission security and resource adequacy criteria would occur in 2016 if the 2,000 MW Indian Point Plant were to be retired at the end of 2015.” NRG further notes that there would be “dramatic and immediate reliability impacts.”[62]

Nucor Steel Auburn, Inc.:

Nucor Steel supports DPS Staff’s cost recovery Straw Proposal. Nucor Steel agrees with a “beneficiaries pay” approach, and an allocation based upon peak coincident demand

[62] NRG comments, February 22, 2013, (no pages numbers on document but would be 2-3 if numbered).

and expanding it to non-transmission solutions (as opposed to the NYTO proposal which only applies to TOTS). Nucor Steel indicates there is a need to recognize and reconcile overlap between this proceeding and the AC Transmission upgrades case (12-T-0502) by affirming that reliability takes precedence for cost allocation. It also suggests that the exit payment mentioned in June Straw Proposal needs more detail.

Paul Heagerty:

Mr. Heagerty maintains that the possible addition of more electric generating plants in New York State could increase his power bill, while the IPEC already produces safe, reliable and clean energy already.

Pure Energy Infrastructure, LLC (Pure Energy):

Pure Energy proffers that the proposals for inclusion in the IPEC Reliability Contingency Plan need to be carefully managed and evaluated to ensure that low-cost, competitive and reliable transmission/generation solutions result. Pure Energy supports the use of the total resource cost test in conducting this evaluation. Pure Energy also advises that multi-unit, distributed generation resources offer unique reliability benefits, which the Commission should consider.

Queens Chamber of Commerce:

The Queens Chamber of Commerce expresses concern about the cost of the June Straw Proposal.

Retail Energy Supply Association (RESA):

RESA contends that this entire proceeding and the development and implementation of various transmission and generation reliability projects rest on the assumption and presumption that the Indian Point generating facility will fail to be relicensed and will be taken out of operation. Under these circumstances, RESA argues it would be prudent for the Commission to move in a cautious and deliberate manner that is reflective of the provisional nature of the entire need for these reliability projects. RESA supports the cost recovery methodologies presented in the DPS Staff June Straw Proposal. According to RESA, including cost recovery in delivery rates is consistent with previous Commission cost recovery approaches such as Renewable Portfolio Standards and Energy Efficiency Portfolio Standards and is administratively simpler/more efficient, as opposed to the approach advocated by Con Edison, et al.

Richard Roberts:

Mr. Roberts opposes the IPEC Reliability Contingency Plan, which he characterizes as a “dangerous and unnecessary path that would exacerbate the climate and air pollution challenges we already face, while at the same time costing us jobs and hurting New York's economy.”

Robert Licata:

Opposes the development of the IPEC Reliability Contingency Plan because it would increase rates, which he maintains are already too high, while the IPEC provides an available source of energy.

Rockland Business Association:

The Rockland Business Association is concerned about the cost of the June Straw Proposal. It argues that there is a fundamental need for the IPEC's continued operation and the multitude of benefits it provides.

Sierra Club:

Sierra Club endorses Con Edison’s aggressive approach to energy efficiency and demand resources. It urges the Commission to require a significantly robust approach to distributed renewable generation to fully capitalize on this useful and cost-effective resource. Sierra Club also encourages the Commission to ensure that the RFP is structured in a way that it will not result in a significant net increase in New York’s greenhouse gas emissions, by carving out a significant role for renewable energy.

Steamfitters Local Union 638:

The Union is dismayed that, with major warning signs about climate change, the Commission would be spending so much time and taxpayer dollars on efforts to close Indian Point -a significant source of carbon-free electricity.

Thomas McCaffrey, Russell Warren, Phil Quesnel, Stephen Juravich, John Kaczor, Christine Rorrenberk, Anthony DeDonato, Neil Burke, Thomas Pulcher, Dan Johnson, Mario Digenova, Joseph Bubel, Michael Delvin, Richard Drake, J.A. Tonkin, Maureen Bubel, Joe Pechacek, Debra Caltabiano, Edward DeGasperis, Roy Spangenberger, Thomas Opet, Lou Merlino, Rich Lamb, Stanhope Waterfield, Mike Harris, James Timone, Daniel Cooke, Leland Cerra, Joseph Rutz, Robert Herrmann, Harry Primrose, Tom Phillips, Cathy Izyk, Adam Kaczmarek, David Buyes, Benjamin Lawrence, Cheryl Croulet, Donald Croulet, Daniel Cooke, Theresa Motko, Tony Iraola, Brett Kenner, Peter Gunsch, Kelly Smith, Arun Thomas, Paul Platt, Kou John Hong, Deborah Fields, James Thompson, Robert Altadonna, Kai Lo, E. Dean Hewitt, Robert Heath, Dennis Skiffington, Ray Fucheck, et al.

These individuals urge the commission to abandon this proceeding as this process is not in the best interest of all New Yorkers. The potential costs in electric rates to plan for the potential closure of a facility that is intent on staying open for business is an inexcusable waste of our limited taxpayer dollars.

Town of Huntington, New York:

The Town supports the repowering of the existing Northport Power Station, which it argues should be included in the IPEC Reliability Contingency Plan.

Town of Putnam Valley, New York:

The Town requests that the Commission withdraw the contingency plan and the June Straw Proposal for cost recovery. It maintains that the consequences of this plan will worsen the current fiscal stress that local governments currently face, and transfer unnecessary cost burdens to ratepayers in the region.

US Power Generating Company, LLC (USPowerGen):

USPowerGen identifies several technical inaccuracies in the descriptions of the USPowerGen projects discussed in the Indian Point Contingency Plan, Draft Generic Environmental Impact Statement July 2013.

Utility Workers Union of America Local 1-2:

The Utility Workers Union of America Local 1-2 supports the continued operation of the IPEC.

Westchester County Association:

The Westchester County Association expresses its deep concern with the June Straw Proposal, and that ratepayers will be saddled with $811 million in added costs for projects that will likely be deemed unnecessary, especially if the plan was solely developed for the purpose of replacing the power from Indian Point.

West Point Partners, LLC (West Point):

West Point maintains that several modifications to the plan proposed in the Con Edison/NYPA February Filing are needed in order to satisfy the requirements of the November 2012 Order. First, West Point suggests that Con Edison should be directed to submit a supplement that assesses other projects now under development. Second, the plan should be modified so as to create a more level playing field between the TOTS and other projects.

White Plains Housing Authority:

The Housing Authority expresses its support that the IPEC should remain in service.

Exhibit No. NYT-8

NEW YORK INDEPENDENT SYSTEM OPERATOR

November 14, 2014

Dear Developers, New York Transmission Owners, Market Participants, and Interested Parties:

The New York Independent System Operator, Inc. (NYISO) hereby withdraws its October 1, 2014 request for the submission of solutions to address the Reliability Needs identified in the 2014 Reliability Needs Assessment (RNA) because the identified needs have been mitigated as described below.

On October 1, 2014 the NYISO requested that potential solutions be submitted on or before December 1, 2014 in order to be evaluated in the NYISO Comprehensive Reliability Plan (CRP). It was noted in that letter that recent resource announcements since the base case was finalized for the 2014 RNA, if implemented, may partially meet the identified Reliability Needs, delay the resource need, and in conjunction with local transmission owner plans (LTPs), relieve transmission security needs.

The NYISO developed a CRP base case, consistent with its tariffs and procedures, which contains more than 1,900 MW of returning generation resources and updates to LTPs that were not included in the RNA. With these updates, the NYISO has determined that the identified resource adequacy and transmission security needs would be fully mitigated. For this reason, the NYISO is no longer requesting or accepting proposed regulated backstop, market-based, or alternative regulated solutions to address the Reliability Needs identified by the 2014 RNA. In the event a reliability need arises that must be addressed prior to the next reliability planning cycle, the NYISO will implement its process to solicit proposals for a Gap Solution pursuant to Section 31.2.10 of the NYISO Open Access Transmission Tariff.

The NYISO is continuing to review the applications submitted by developers to satisfy the qualification requirements for participation in the NYISO's reliability planning process. Developers determined by the NYISO to be qualified will be eligible to participate in the reliability planning process for a three-year period, subject to complying with the NYISO's tariff requirements and procedures.

Questions about the CRP process can be addressed to Yachi Lin (ylin@nyiso.com, 518-356-8724) or Carl Patka (cpatka@nyiso.com, 518-356-6220).

Very truly yours,

Henry Chao
Vice President, System & Resource Planning

Exhibit No. NYT-9

NEWS

NYISO resource needs ease amid new plans

With updated information, the New York Independent System Operator has withdrawn its request for solutions to address reliability needs that were identified in NYISO's 2014 reliability needs assessment, which was released in September.

NYISO developed a comprehensive reliability plan that contains more than 1,900 MW of returning generation resources and updates to local transmission owner plans that were not included in the reliability needs assessment, Henry Chao, NYISO's vice president, system and resource planning, said in a letter to the Public Service Commission.

The ISO previously identified a resource deficiency in southeast New York, beginning with about 100 MW in 2019 and increasing to 1,200 MW by 2024. There were also four regions that did not satisfy transmission security reliability criteria, which contributed to the reliability needs, NYISO said in an October 1 letter seeking solutions.

However, transmission, generation and demand response could be used to address the resource deficiency and transmission needs, NYISO said last week. "With these updates [in the comprehensive reliability plan], the NYISO has determined that the identified resource adequacy and transmission security needs would be fully mitigated,' the grid operator told the PSC.

If a reliability need arises that must be addressed before the next reliability planning cycle, NYISO will solicit proposals for a gap solution, Chao said.

NYISO said in the October 1 request for solutions that five project not included in the 2014 reliability needs assessment could partially meet the reliability needs.

They include NRG Energy's plan to repower three units totaling 435 MW at the Dunkirk plant to burn natural gas and Danskammer Energy's plan to repower four units totaling 500 MW with natural gas. Two of the Danskammer units are already operating and the other two will be operating by the end of the year, according to Danskammer Energy.

Selkirk Cogen Partners has withdrawn its notice of intent to mothball two units totaling 345 MW. In May, it offered the units into a request for proposals by the New York Power Authority.

Binghamton BOP on September 24 notified NYISO that it intends to return to service a 47.7 MW power plant.

In addition, Consolidated Edison plans to implement 125 MW of demand response, energy efficiency and combined heat and power projects, NYISO said.

"These recent announcements, if implemented, would delay the resource need identified in the resource needs assessment by approximately four years under base case conditions," NYISO said.

— Mary Powers

FERC inks 4th settlement on Southwest blackout

Federal regulators and a US power marketing administration have reached a deal to resolve reliability violations linked to the 2011 Southwest blackout, with the settlement requiring specific actions to improve reliability but no financial penalty.

The Federal Energy Regulatory Commission found that the settlement between Western Area Power Administration – Desert Southwest Region, the North American Electric Reliability Corp. and FERC's enforcement office was consistent with the public interest and a "a fair and equitable resolution of this matter."

The settlement is the fourth FERC has reached with an entity connected to the 2011 blackout, which left more than 5 million people in Southern California, Arizona and Baja, Mexico, without power for up to 12 hours.

FERC staff and NERC found that WAPA-DSW violated reliability standards linked to voltage and reactive control as well as transmission operations (IN14-9), with a commission statement noting that WAPA-DSW "failed to operate its portion of the transmission system within voltage system operating limits and to maintain sufficient situational awareness prior to and

Subscriber note

Several market participants have requested a change in the Christmas week trading calendar for December 2014. They have requested that Friday December 26, 2014 be treated as a holiday for both daily and bidweek natural gas trading and the Gas Daily and Megawatt Daily publications.

The potential treatment of December 26 as a holiday would have several implications as listed below:

Natural Gas Pricing:

1. Gas Daily trades transacted on Wednesday, December 24 would be for flow Thursday, December 25-Monday, December 29.
2. December 26 would be a bidweek holiday. Therefore January 2015 bidweek trading would encompass Tuesday, December 23, Wednesday, December 24, Monday, December 29, Tuesday, December 30, and Wednesday, December 31.

Power Pricing:

1. West power markets are trading on December 26. On Tuesday, December 23, they are trading for flow on December 24-26. On Friday, December 26, they are trading for flow on December 27-29. Platts would not deviate from this schedule. However, no assessments will be done on December 26. Instead, the data gathered on December 26 will be reviewed and assessments will be made for those flow dates on Monday, December 29.
2. Retroactive assessments would be done for the East power markets.

Services and Publication:

1. No Platts services or publications for December 26, 2014.

Please submit any comments in favor of or against a change in the trading and publication schedule of natural gas and power for December 26 to Gas_Survey_Comments@platts.com and PriceGroup@platts.com by November 26 at 5 pm EST. Platts will publish its decision later the same day.

Exhibit No. NYT-10

2014 Reliability Needs Assessment

New York Independent System Operator

FINAL REPORT

September 16, 2014

Caution and Disclaimer

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Executive Summary

The 2014 Reliability Needs Assessment (RNA) assesses resource adequacy and both transmission security and adequacy of the New York Control Area (NYCA) bulk power transmission system from year 2015 through 2024, the study period of this RNA. The 2014 RNA identifies transmission security needs in portions of the bulk power transmission system, and a NYCA LOLE violation due to inadequate resource capacity located in Southeast New York (SENY).

The NYISO finds transmission security violations beginning in 2015, some of which are similar to those found in the 2012 RNA. The NYISO also identifies resource adequacy violations, which begin in 2019 and increase through 2024.

For transmission security, there are four primary regions with reliability needs: Rochester, Western & Central New York, Capital Region, and Lower Hudson Valley & New York City. These reliability needs are generally driven by recent and proposed generator retirements or mothballing combined with load growth. The New York transmission owners have developed plans through their respective local transmission planning processes to construct transmission projects to meet not only the needs identified in the previous RNA, but also any additional needs occurring since then and prior to this RNA. These transmission projects, subject to inclusion rules, have been modeled in the 2014 RNA base case. Reliability needs identified in this report exist despite the inclusion of the transmission projects in the base case, or exist until certain projects are completed. The transmission security needs in the Buffalo and Binghamton areas are influenced by whether the fuel conversion project can be completed for the Dunkirk Plant for it to return to service by 2016. As a result, this project was addressed as a sensitivity and the impact of the results are noted with the base case reliability needs.

While resource adequacy violations continue to be identified in SENY, the 2014 RNA is projecting the need year to be 2019, one year before the need year identified in the 2012 RNA. The most significant difference between the 2012 RNA and the 2014 RNA is the decrease of the NYCA capacity margin (the total capacity less the peak load forecast).

For summer 2014 resource adequacy, the existing capacity provides about a 122.7% Installed Capacity Reserve to meet the summer 2014 Installed Reserve Margin requirement of 117.0%. The capacity margin decreases throughout the study period, but more rapidly in the outer years due to load growth. The NYISO calculated the difference in the capacity margin between the 2012 RNA and the 2014 RNA in the need year of 2019 and determined a net decrease of 2,100 MW. The difference breaks down as follows:

1. The NYCA capacity resources are 874 MW less for 2019 (724 MW upstate and 150 MW in SENY);
2. The NYCA baseline load forecast is 250 MW higher for 2019 (497 MW higher upstate and 247 MW lower in SENY); and
3. The NYCA Special Case Resources (SCRs) projection is 976 MW less for 2019 (685 MW upstate and 291 MW in SENY).

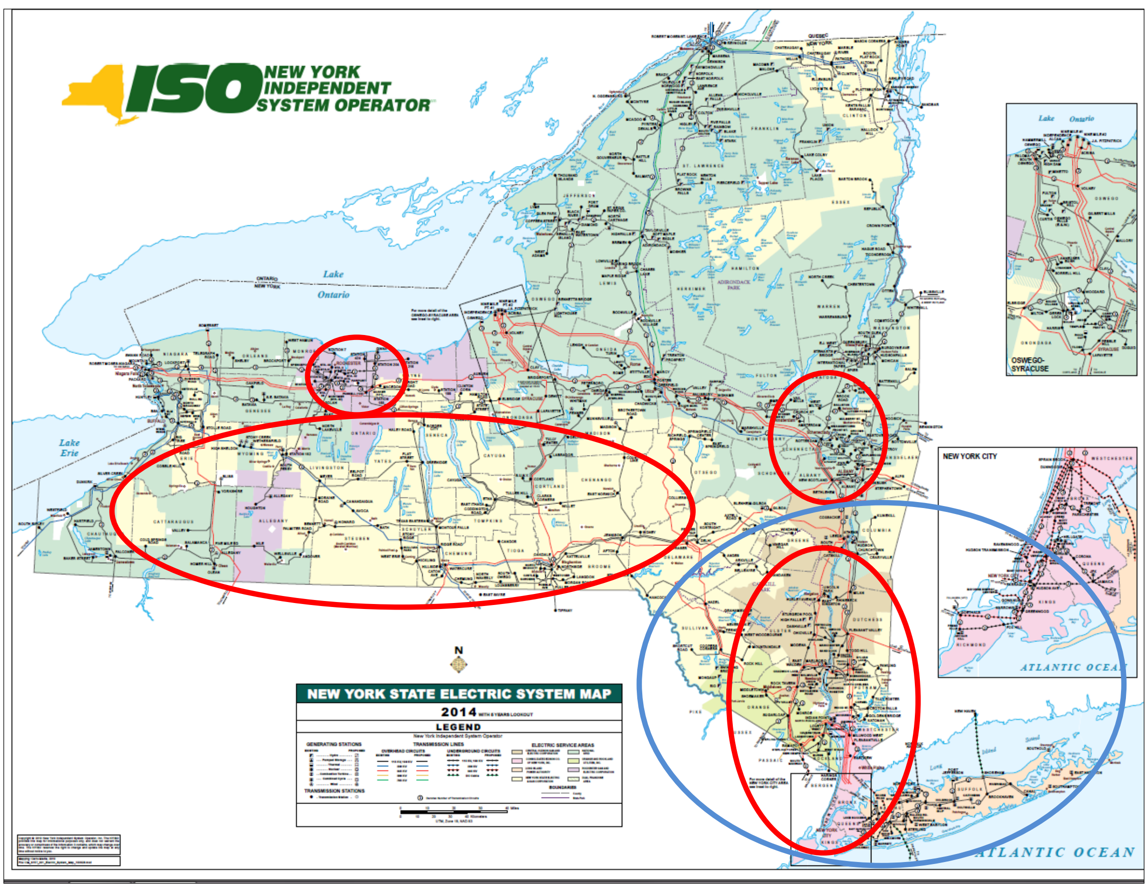
The reliability needs identified in the 2014 RNA are summarized in Table 1 below, and the approximate locations of the regions are marked on Figure 1.

Table 1: Reliability Needs identified in 2014 RNA

Year of Need	Transmission Security Violations (Area/Load Zone/Transmission Owner)	Resource Adequacy (LOLE)
2015	Rochester Area in Genesee (Zone B), owned by RG&E	No violation
	Binghamton Area in Central (Zone C), owned by NYSEG*	
	Syracuse Area in Central (Zone C), owned by N. Grid	
	Utica Area in Mohawk Valley (Zone E), owned by N. Grid	
	Albany Area in Capital (Zone F), owned by N. Grid	
2016	No additional violations	
2017	Rochester Area issues mitigated	
	Additional Syracuse Area in Central (Zone C), owned by N. Grid	
	Additional Utica Area in Mohawk Valley (Zone E), owned by N. Grid*	
	Binghamton Area voltage in Central (Zone C), owned by NYSEG	
2018	Buffalo Area in Dysinger (Zone A), owned by N. Grid*	
2019	No additional violations	Violation (LOLE = 0.11)
2020	Additional Binghamton Area in Central (Zone C), owned by NYSEG*	Violation (LOLE = 0.13)
2021	Additional Buffalo Area in West (Zone A), owned by N. Grid*	Violation (LOLE = 0.15)
2022	Additional Buffalo Area in West (Zone A), owned by N. Grid*	Violation (LOLE = 0.18)
	Transmission between Capital (Zone F) and Hudson Valley (Zone G), owned by N. Grid	
2023	No additional violations	Violation (LOLE = 0.22)
2024	No additional violations	Violation (LOLE = 0.26)

* Some violations would be resolved upon the return of the Dunkirk plant to service.

Figure 1: Approximate Locations of Reliability Needs



Note: The red circles indicate the areas where the load may be impacted by transmission security constraints, and the blue circle indicates the region with resource adequacy violations.

The NYISO expects existing and recent market rule changes to entice market participants to take actions that will help meet the resource adequacy needs in SENY, as identified by the 2012 RNA and the 2014 RNA. The resources needed downstream of the upstate New York to SENY interface is approximately 1,200 MW in 2024 (100 MW in 2019), which could be transmission or capacity resources. The new Zones G-J Locality will provide market signals for resources to provide service in this area. Capacity owners and developers are taking steps to return mothballed units to service, restore units to their full capability, or build new in the Zones G-J Locality. If some or all of these units return to service or are developed, the reliability need year would be postponed beyond 2019. In addition, other measures, such as the demand response, energy efficiency and CHP projects, would also postpone the reliability need year beyond 2019. New York State Public Service Commission is also promoting regulated transmission development to relieve the transmission constraints between upstate New York and SENY, which could also defer the need for additional resources. Potential solutions will be submitted for evaluation during the solutions phase of the Reliability Planning Process (RPP) and included in the upcoming 2014 Comprehensive Reliability Plan (CRP) if appropriate.

As a backstop to market-based solutions, the NYISO employs a process to define responsibility should the market fail to provide an adequate solution to an identified reliability need. Since there are transmission security violations in Zones A, B, C, E, and F within the study period, the transmission owners (TOs) in those zones (i.e., National Grid, RGE, and NYSEG) are responsible and will be tasked to develop detailed regulated backstop solutions for evaluation in the 2014 CRP.

Given the limited time between the identification of certain transmission security needs in this RNA report and their occurrence in 2015, the use of demand response and operating procedures, including those for emergency conditions, may be necessary to maintain reliability during peak load periods until permanent solutions can be put in place. Accordingly, the NYISO expects the TOs to present updates to their Local Transmission Owner Plans for these zones, including their proposed operating procedures pending completion of their permanent solutions, for review and acceptance by the NYISO and in the 2014 CRP.

The NYISO identified reliability needs for resource adequacy in SENY starting in the year 2019; therefore, the TOs in SENY (i.e., Orange & Rockland, Central Hudson, New York State Electric and Gas, Con Edison, and LIPA) are responsible to develop the regulated backstop solution(s). The study also identified a transmission security violation in 2022 on the Leeds-Pleasant Valley 345 kV circuit, and this circuit is the main constraint of the Upstate New York to Southeast New York (UPNY-SENY) interface identified in the resource adequacy analysis. Therefore, the violation could be resolved by solution(s) that respond to the resource adequacy deficiencies identified for 2019 – 2024.

If the resource adequacy solution is non-transmission, these reliability needs can only be most efficiently satisfied through the addition of compensatory megawatts in SENY because such resources need to be located below the UPNY-SENY interface constraint to be effective. Additions in Zones A through F could partially resolve these reliability needs. Potential solutions could include a combination of additional transfer capability by adding transmission facilities into SENY from outside those zones and/or resource additions at least some of which would be best located in SENY.

In addition, the 2014 RNA provides analysis of risks to the Bulk Power Transmission Facilities under certain sensitivities and scenarios to assist developers and stakeholders to propose market-based and regulated reliability solutions as well as policy makers to formulate state policy. The 2014 RNA analysis included a sensitivity of the Dunkirk Fuel conversion project, and scenarios to address recent experiences in the NYISO operations, which revealed potential future reliability risks caused particularly by generation retirements, fuel availability, or other factors that could limit energy production during the extreme winter weather. The findings under the sensitivity and scenario conditions are:

- *Dunkirk Fuel Conversion Project*: The availability of Dunkirk after the fuel conversion project in 2016 resolves thermal transmission security violations in the Buffalo and Binghamton areas, but does not resolve the resource adequacy needs identified in 2019 and thereafter.
- *High (econometric) Load Forecast*: Resource adequacy violations occur as soon as 2017.
- *Indian Point Energy Center Plant Retirement*: Reliability violations would occur in 2016 if the Indian Point Plant were to be retired at the latter of the two units' current license expiration dates in December 2015.
- *Zonal Capacity at Risk*: For year 2015, removal of up to 2,500 MW in Zones A through F, 650 MW in Zones G through I, 650 MW in Zone J, or 550 MW in Zone K would result in a NYCA resource adequacy violation.
- *Transmission Security under 90/10 Forecasted Load*: The 90/10 forecast for the statewide coincident summer peak is on average approximately 2,400 MW higher than the baseline 50/50 forecast. This higher load would result in the earlier occurrence of the reliability needs identified in the base case as well as the occurrence of new violations in the same four primary regions. In addition, based on the assumptions applied in this analysis, beginning in 2017 there would be insufficient resources to meet the minimum 10-minute operating reserve requirement of 1,310 MW. Starting in 2020, there would be insufficient resources to meet the modeled 90/10 peak load under pre-contingency conditions.
- *Stressed Winter Scenario*: The winter of 2013-2014 experienced five major cold snaps, including three polar vortex events that extended across much of the country. The NYISO set a new winter peak load of 25,738 MW, while neighboring ISOs and utilities concurrently set record winter peaks during the month of January. Compounding the impact from high load conditions, extensive generation derates and gas pipeline constraints occurred simultaneously due to the extreme winter weather. In the extreme case that NYCA is assumed to be unable to receive any emergency assistance from neighboring areas, it would take a loss of capacity in excess of 7,250 MW due to energy production constraints in extreme winter conditions to cause a resource adequacy violation in 2015.

In addition to the scenarios, the NYISO also analyzed the risks associated with the cumulative impact of environmental laws and regulations, which may affect the flexibility in plant operation and may make fossil plants energy-limited resources. The RNA discusses the environmental regulations that affect long term power system planning and highlights the impacts of various environmental drivers on resource availability.

The RNA is the first step of the NYISO reliability planning process. As a product of this step, the NYISO documents the reliability needs in the RNA report, which is presented to the NYISO Board of Directors for approval. The NYISO Board approval initiates the second step, which involves the NYISO requesting proposed solutions to mitigate the identified needs to maintain acceptable levels of system reliability throughout the study period.

As part of its ongoing reliability planning process, the NYISO monitors and tracks the progress of market-based projects, regulated backstop solutions, together with other resource additions and retirements, consistent with its obligation to protect confidential information under its Code of Conduct. The other tracked resources include: (i) units interconnecting to the bulk power transmission system; (ii) the development and installation of local transmission facilities; (iii) additions, mothballs or retirement of generators; (iv) the status of mothballed/retired facilities; (v) the continued implementation of New York State energy efficiency and similar programs; (vi) participation in the NYISO demand response programs; and (vii) the impact of new and proposed environmental regulations on the existing generation fleet.

1. Introduction

The Reliability Needs Assessment (RNA) is developed by the NYISO in conjunction with Market Participants and all interested parties as its first step in the Comprehensive System Planning Process (CSPP). The RNA is the foundation study used in the development of the NYISO Comprehensive Reliability Plan (CRP). The RNA is performed to evaluate electric system reliability, for both transmission security and resource adequacy, over a 10-year study period. If the RNA identifies any violation of Reliability Criteria for Bulk Power Transmission Facilities (BPTF), the NYISO will report a Reliability Need quantified by an amount of compensatory megawatts (MW). After approval of the RNA, the NYISO will request market-based and alternative regulated proposals from interested parties to address the identified Reliability Needs, and designate one or more Responsible Transmission Owners to develop a regulated backstop solution to address each identified Reliability Need. This report sets forth the NYISO's findings for the study period 2015-2024.

The CRP will provide a plan for continued reliability of the bulk power system during the study period depending on a combination of additional resources. The resources may be provided by market-based solutions being developed in response to market forces and the request for solutions following the approval of this RNA. If the market does not adequately respond, continued reliability will be ensured by either regulated solutions being developed by the TOs which are obligated to provide reliable service to their customers or alternative regulated solutions being developed by others. To maintain the system's long-term reliability, these additional resources must be readily available or in development at the appropriate time of need. Just as important as the electric system plan is the process of planning itself. Electric system planning is an ongoing process of evaluating, monitoring and updating as conditions warrant. Along with addressing reliability, the CSPP is also designed to provide information that is both informative and of value to the New York wholesale electricity marketplace.

Proposed solutions that are submitted in response to an identified Reliability Need are evaluated in the development of the CRP and must satisfy Reliability Criteria. However, the solutions submitted to the NYISO for evaluation in the CRP do not have to be in the same amounts of MW or locations as the compensatory MW reported in the RNA. There are various combinations of resources and transmission upgrades that could meet the needs identified in the RNA. The reconfiguration of transmission facilities and/or modifications to operating protocols identified in the solution phase could result in changes and/or modifications of the needs identified in the RNA.

This report begins with a summary of the 2012 CRP and prior reliability plans. The report continues with a summary of the load and resource forecast for the next 10 years, RNA base case assumptions and methodology, and reports the RNA findings for years 2015 through 2024. Detailed analyses, data and results, and the underlying modeling assumptions are contained in the appendices.

The RPP tests the robustness of the needs assessment studies and determines, through the development of appropriate scenarios, factors and issues that might adversely impact the reliability of the BPTF. The scenarios that were considered include: (i) high load (econometric forecast prior to inclusion of statewide energy efficiency programs and retail solar photovoltaic (PV), that increases the load by approximately 2,000 MW by 2024); (ii) Indian Point Plant retirement; (iii) 90/10 load forecast; (iv) zonal capacity at risk; and (v) stressed winter conditions. In addition to assessing the base case conditions and scenarios, the impact of the Dunkirk plant fuel conversion is analyzed as a sensitivity.

The NYISO will prepare and issue its 2014 CRP based upon this 2014 RNA report. The NYISO will monitor the assumptions underlying the RNA base case as well as the progress of the market-based solutions submitted in earlier CRPs and projects that have met the NYISO's base case inclusion rules for this RNA. These base case assumptions include, but are not limited to, the measured progress towards achieving the State energy efficiency program standards, the impact(s) of ongoing developments in State and Federal environmental regulatory programs on existing power plants, the status of plant re-licensing efforts, and the development of transmission owner projects identified in the Local Transmission Plans (LTPs).

For informational purposes, this RNA report also provides the marketplace with the latest historical information available for the past five years of congestion via a link to the NYISO's website. The 2014 CRP will be the foundation for the 2015 Congestion Assessment and Resource Integration Study (CARIS). A more detailed evaluation of system congestion is presented in the CARIS.

2. Summary of Prior CRPs

This is the seventh RNA since the NYISO planning process was approved by FERC in December 2004. The first three RNA reports identified Reliability Needs and the first three CRPs (2005-2007) evaluated the market-based and regulated backstop solutions submitted in response to those identified needs. The 2009 CRP and the 2010 CRP indicated that the system did not exhibit any violations of applicable reliability criteria and no solutions were necessary to be solicited. Therefore, market-based and regulated solutions were not requested. The 2012 RNA identified Reliability Needs and the 2012 CRP evaluated market-based and regulated solutions in response to those needs. The NYISO has not previously triggered any regulated backstop solutions to meet previously identified Reliability Needs due to changes in system conditions and sufficiency of projects coming into service.

Table 2-1 presents the market solutions and TOs' plans that were submitted in response to previous requests for solutions. These solutions were included in the 2012 CRP and the information concerning these solutions has been updated herein to reflect their current status. The table also indicates that 1,545 MW of solutions are either in-service or are still being reported to the NYISO as moving forward with the development of their projects.

In addition to those projects in Table 2-1, there are a number of other projects in the NYISO interconnection study queue which are also moving forward through the interconnection process, but have not been offered as market solutions in this process. Some of these additional generation resources have either accepted their cost allocation as part of a Class Year Facilities Study process or are included in the currently ongoing 2012 Class Year Facilities Study. These projects are listed in Table 2-2 and 2-3 in the order of each project's proposed in-service dates. The projects that meet the 2014 RNA base case inclusion rules are included in Table 3-3. The listings of other Class Year Projects can be found along with other projects that have not met inclusion rules.

Table 2-1: Current Status of Tracked Market-Based Solutions & TOs' Plans

Queue #	Project	Submitted	Zone	Original In-Service Date	Name Plate (MW)	CRIS (MW)	Summer (MW)	Proposal Type	Current Status	Included in 2014 RNA Base Case?
69	Empire Generation Project	CRP 2008	F	Q1 2010	670	592.4	577.1	Resource Proposal	In-Service	Yes
206	Back-to-Back HVDC, AC Line HTP	CRP 2007, CRP 2008, and was an alternative regulated proposal in CRP 2005	PJM - J	Q2 2011	660	660	660	Transmission Proposal	In-Service	Yes
153	ConEd M29 Project	CRP 2005	J	May 2010	N/A	N/A	N/A	TO's Plans	In-Service	Yes
-	Sta 80 xfmr replacement	CRP 2012	B	2014	N/A	N/A	N/A	TO's Plans	In-Service	Yes
-	Ramapo Protection Addition	CRP2012	G	2013	N/A	N/A	N/A	TO's Plans	In-Service	Yes
-	5 Mile Road Substation	CRP2012	A	-	N/A	N/A	N/A	TO's Plans	Summer 2015	Yes
201, 224	Gas Turbine NRG Astoria re-powering	CRP 2005, CRP 2007, CRP 2008, CRP 2012	J	June 2010	278.9	155	250	Resource Proposal	June 2017	No
339	Station 255	CRP 2012	B	-	N/A	N/A	N/A	TO's Plans	Q4 2016	Yes
-	Clay – Teall #10 115kV	CRP2012	C	2016	N/A	N/A	N/A	TO's Plans	Q4 2017	Yes

Table 2-2: Proposed Generation Projects from Completed Class Years

Queue #	Owner/Operator	Station Unit	Zone	Proposed In-Service Date	Name Plate (MW)	CRIS (MW)	Summer (MW)	Unit Type	Class Year	Included in 2014 RNA?
237	Allegany Wind, LLC	Allegany Wind	A	2015/11	72.5	0.0	72.5	Wind Turbines	2010	No
197	PPM Roaring Brook, LLC / PPM	Roaring Brook Wind	E	2015/12	78.0	0.0	78.0	Wind Turbines	2008	No
349	Taylor Biomass Energy Mont., LLC	Taylor Biomass	G	2015/12	21.0	19.0	19.0	Solid Waste	2011	Yes
251	CPV Valley, LLC	CPV Valley Energy Center	G	2016/05	820.0	680.0	677.6	Combined Cycle	2011	No
201	NRG Energy	Berrians GT	J	2017/06	200.0	155.0	200.0	Combined Cycle	2011	No
224	NRG Energy, Inc.	Berrians GT II	J	2017/06	78.9	0.0	50.0	Combined Cycle	2011	No

Table 2-3: Other Proposed Generation Projects

Queue #	Owner/Operator	Station Unit	Zone	Proposed In-Service Date	Name Plate (MW)	CRIS (MW)	Summer (MW)	Unit Type	Included in 2014 RNA?
372	Dry Lots Wind, LLC	Dry Lots Wind	E	2014/11	33.0	TBD	33.0	Wind Turbines	No
354	Atlantic Wind, LLC	North Ridge Wind	E	2014/12	100.0	TBD	100.0	Wind Turbines	No
276	Air Energie TCI, Inc.	Crown City Wind	C	2014/12	90.0	TBD	90.0	Wind Turbines	No
371	South Moutain Wind, LLC	South Mountain Wind	E	2014/12	18.0	TBD	18.0	Wind Turbines	No
361	US PowerGen Co.	Luyster Creek Energy	J	2015/06	508.6	TBD	401.0	Combined Cycle	No
360	NextEra Energy Resources, LLC	Watkins Glen Wind	C	2015/07	122.4	TBD	122.4	Wind Turbines	No
382	Astoria Generating Co.	South Pier Improvement	J	2015/07	190.0	TBD	88.0	Combustion Turbines	No
347	Franklin Wind Farm, LLC	Franklin Wind	E	2015/12	50.4	TBD	50.4	Wind Turbines	No
270	Wind Development Contract Co, LLC	Hounsfield Wind	E	2015/12	244.8	TBD	244.8	Wind Turbines	No
266	NRG Energy, Inc.	Berrians GT III	J	2016/06	278.9	TBD	250.0	Combined Cycle	No
383	NRG Energy, INC.	Bowline Gen. Station Unit #3	G	2016/06	814.0	TBD	775.0	Combined Cycle	No
310	Cricket Valley Energy Center, LLC	Cricket Valley Energy Center	G	2018/01	1308.0	TBD	1019.9	Combined Cycle	No
322	Rolling Upland Wind Farm, LLC	Rolling Upland Wind	E	2018/10	59.9	TBD	59.9	Wind Turbines	No

3. RNA Base Case Assumptions, Drivers and Methodology

The NYISO has established procedures and a schedule for the collection and submission of data and for the preparation of the models used in the RNA. The NYISO's CSPP procedures are designed to allow its planning activities to be performed in an open and transparent manner under a defined set of rules and to be aligned and coordinated with the related activities of the NERC, NPCC, and New York State Reliability Council (NYSRC). The assumptions underlying the RNA were reviewed at the Transmission Planning Advisory Subcommittee (TPAS) and the Electric System Planning Working Group (ESPWG). The Study Period analyzed in the 2014 RNA is the ten years from 2015 through 2024 for the base case, sensitivity and scenarios.

All studies and analyses of the RNA base case reference the same energy and peak demand forecast, which is the baseline forecast reported in the 2014 Gold Book. The baseline forecast is an econometric forecast with an adjustment to reflect projected gains (i.e., load reduction) associated with statewide energy efficiency programs and retail solar PV installations.

The study base cases were developed in accordance with NYISO procedures using projections for the installation and retirement of generation resources and transmission facilities that were developed in conjunction with market participants and Transmission Owners. These are included in the base case using the NYISO 2014 FERC 715 filing as a starting point, and consistent with the base case inclusion screening process provided in the Reliability Planning Process (RPP) Manual. Resources that choose to participate in markets outside of New York are modeled as contracts, thus preventing their capacity from being used to meet resource adequacy requirements in New York. Representations of neighboring systems are derived from interregional coordination conducted under the NPCC, and pursuant to the Northeast ISO/RTO Planning Coordination Protocol.

Table 3-3 shows the new projects which meet the screening requirements for inclusion in the RNA base case.

3.1. **Annual Energy and Summer Peak Demand Forecasts**

There are two primary forecasts modeled in the 2014 RNA, as contained in the 2014 Gold Book. The first forecast, which is used in a scenario, is an econometric forecast of annual energy and peak demand. The second forecast, which is used for the 2014 RNA base case, includes projected reductions for the impacts of energy efficiency programs and retail solar PV power[1].

The NYISO's energy efficiency estimates include the impact of programs authorized by the Energy Efficiency Portfolio Standards (EEPS), New York Power Authority (NYPA), and Long Island Power Authority (LIPA). The NYISO has been a party to the EEPS proceeding from its inception and is now an *ex-officio* member of the E^2 advisory group, the successor to the Evaluation Advisory Group, which is responsible for advising the New York State Public Service Commission (NYDPS) on energy efficiency related issues and topics. The NYISO reviewed and discussed with market participants in the ESPWG and TPAS, projections for the potential impact of both energy efficiency and the EEPS over the 10-year Study Period. The factors considered in developing the 2014 RNA base case forecast are included in Appendix C.

The assumptions for the 2014 economic growth, energy efficiency program impacts and retail solar PV impacts were discussed with market participants during meetings of the ESPWG and TPAS during the first quarter of 2014. The ESPWG and TPAS reviewed and discussed the assumptions used in the 2014 RNA base case forecast in accordance with procedures established for the RNA.

The annual average energy growth rate in the 2014 Gold Book decreased to 0.16%, as compared to 0.59% in the 2012 Gold Book. The 2014 Gold Book's annual average summer peak demand growth decreased to 0.83%, as compared to 0.85% in the 2012 Gold Book. The lower energy growth rate is attributed to the influence of both the economy and the continued impact of energy efficiency and retail solar PV. While these factors had a smaller impact on summer peak growth than on annual energy growth, the expectation for peak growth is still lower in 2014 than it was in 2012. Due to the low growth rates in both energy and summer peak demand, the value in performing a low-growth scenario for the RNA was diminished, and thus, this scenario was not modeled in the 2014 RNA.

Table 3-1 below summarizes the 2014 RNA econometric forecast and the 2012 RNA base case forecast. Table 3-1 shows a comparison of the base case forecasts and energy efficiency program impacts contained in the 2012 RNA and the 2014 RNA. Figure 3-1 and Figure 3-2 present actual, weather-normalized and forecasts of annual energy and summer peak demand for the 2014 RNA. Figure 3-3 and Figure 3-4 present the NYISO's projections of annual energy and summer peak demand in the 2014 RNA for energy efficiency and retail solar PV.

[1] The term retail solar PV is used to refer to customer-sited solar PV, to distinguish it from large-scale solar PV that is considered as part of the fleet of electric generation in the state.

Table 3-1: Comparison of 2012 & 2014 RNA Base Case Forecasts

Comparison of Base Case Energy Forecasts - 2012 & 2014 RNA (GWh)

Annual GWh	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2012 RNA Base Case	163,659	164,627	165,340	166,030	166,915	166,997	168,021	169,409	171,176	172,514	173,569		
2014 RNA Base Case			163,161	163,214	163,907	163,604	163,753	164,305	165,101	164,830	164,975	165,109	165,721
Change from 2012 RNA			-2,179	-2,816	-3,008	-3,393	-4,268	-5,104	-6,075	-7,684	-8,594	NA	NA

Comparison of Base Case Peak Forecasts - 2012 & 2014 RNA (MW)

Annual MW	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2012 RNA Base Case	33,295	33,696	33,914	34,151	34,345	34,550	34,868	35,204	35,526	35,913	36,230		
2014 RNA Base Case			33,666	34,066	34,412	34,766	35,111	35,454	35,656	35,890	36,127	36,369	36,580
Change from 2012 RNA			-248	-85	67	216	243	250	130	-23	-103	NA	NA

Comparison of Energy Impacts from Statewide Energy Efficiency Programs & Retail Solar PV - 2012 RNA & 2014 RNA (GWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2012 RNA Base Case	1,919	3,462	5,140	6,645	7,903	9,149	10,066	10,670	11,230	11,755	12,244		
2014 RNA Base Case	1,919	3,462	4,823	6,558	8,099	9,395	10,449	11,455	12,439	13,341	14,228	15,108	15,975
Change from 2012 RNA			-317	-87	196	246	383	785	1,209	1,586	1,984	NA	NA

Comparison of Peak Impacts from Statewide Energy Efficiency & Retail Solar PV - 2012 RNA & 2014 RNA (MW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2012 RNA Base Case	343	624	932	1,210	1,446	1,674	1,861	1,983	2,101	2,217	2,324		
2014 RNA Base Case	343	624	848	1,115	1,372	1,549	1,715	1,867	2,025	2,169	2,314	2,456	2,703
Change from 2012 RNA			-84	-95	-74	-125	-146	-116	-76	-48	-10	NA	NA

Table 3-2: Comparison of 2014 RNA Base Case Forecast and High Load (Econometric) Scenario

Annual GWh	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2014 High Load Scenario	164,522	166,310	168,544	169,537	170,740	172,298	174,078	174,709	175,741	176,755	178,234
2014 RNA Base Case	163,161	163,214	163,907	163,604	163,753	164,305	165,101	164,830	164,975	165,109	165,721

Energy Impacts of EE Programs & Retail Solar PV

Cumulative GWh	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2014 RNA Base Case	1,361	3,096	4,637	5,933	6,987	7,993	8,977	9,879	10,766	11,646	12,513

Annual MW	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2014 High Load Scenario	33,890	34,557	35,160	35,691	36,202	36,697	37,057	37,435	37,817	38,201	38,659
2014 RNA Base Case	33,666	34,066	34,412	34,766	35,111	35,454	35,656	35,890	36,127	36,369	36,580

Summer Peak Demand Impacts of EE Programs & Retail Solar PV

Cumulative MW	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2014 RNA Base Case	224	491	748	925	1,091	1,243	1,401	1,545	1,690	1,832	2,079

Figure 3-1: 2014 Base Case Energy Forecast and Scenarios

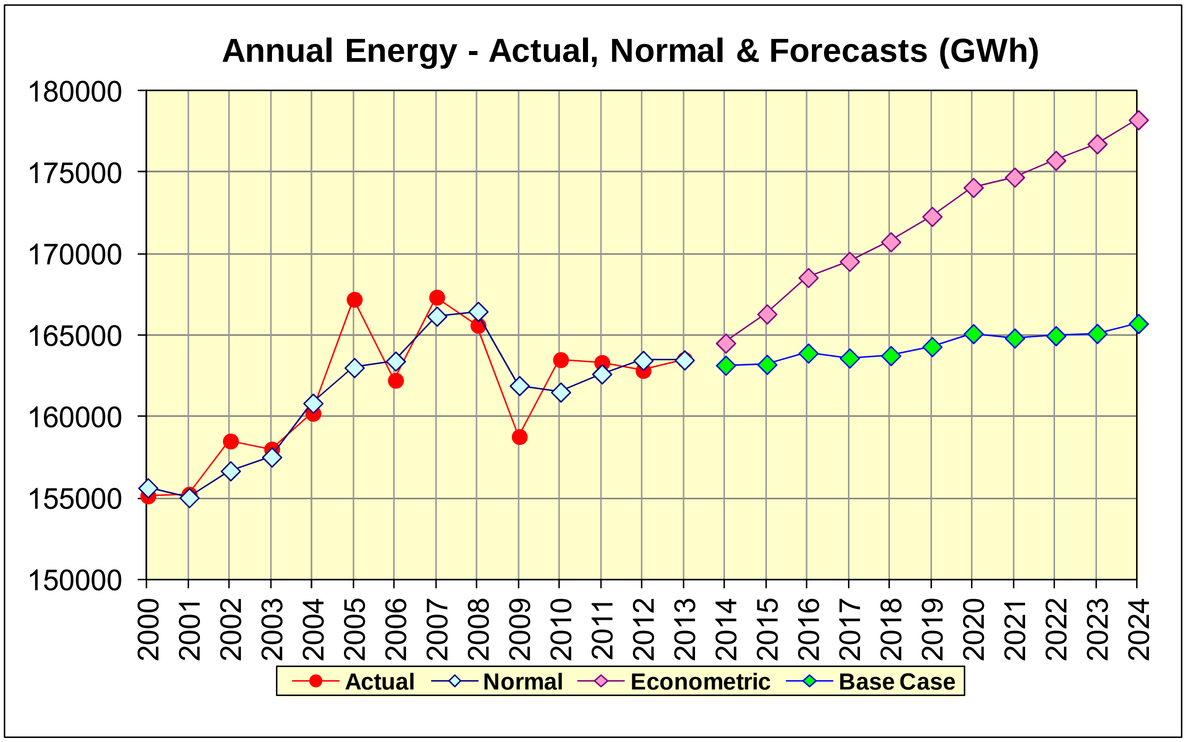
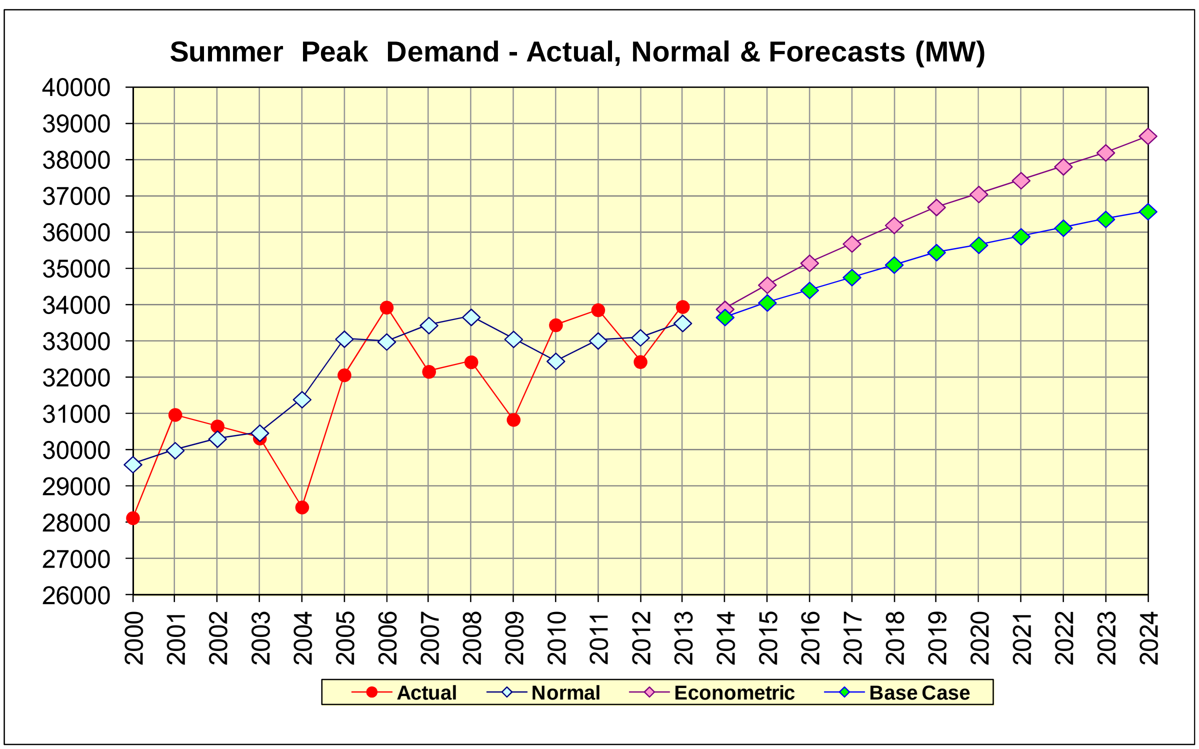


Figure 3-2: 2014 Base Case Summer Peak Demand Forecast and Scenarios



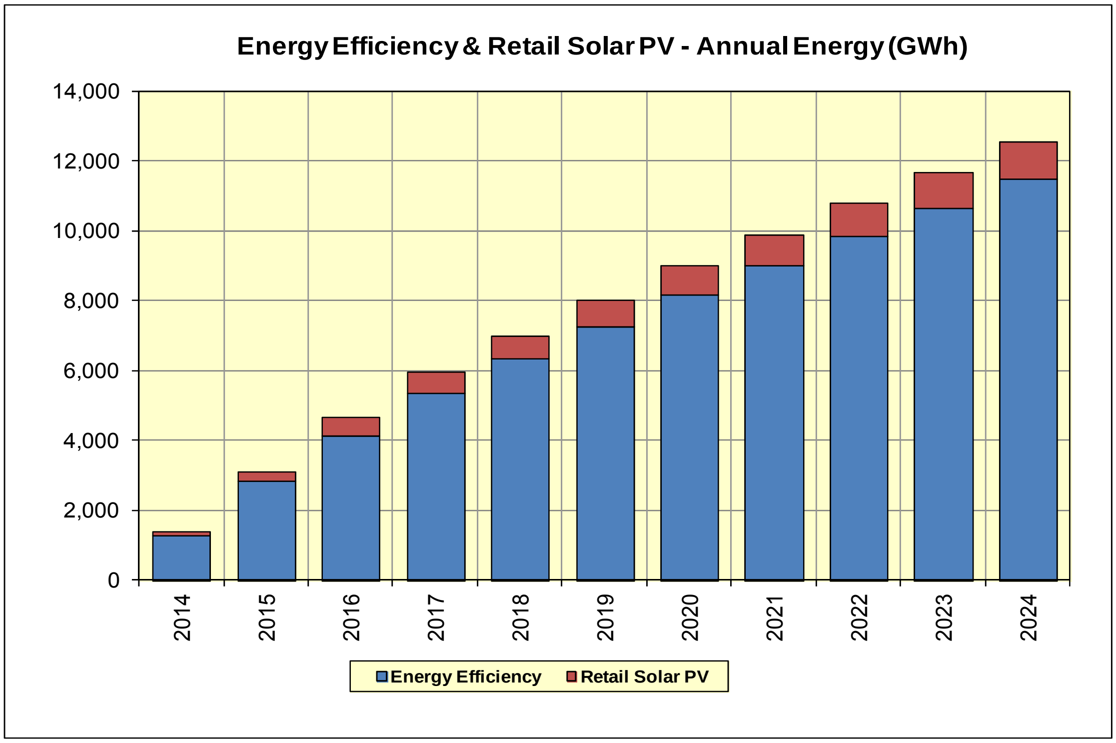


Figure 3-3: 2014 Base Case Energy Efficiency & Retail Solar PV – Annual Energy

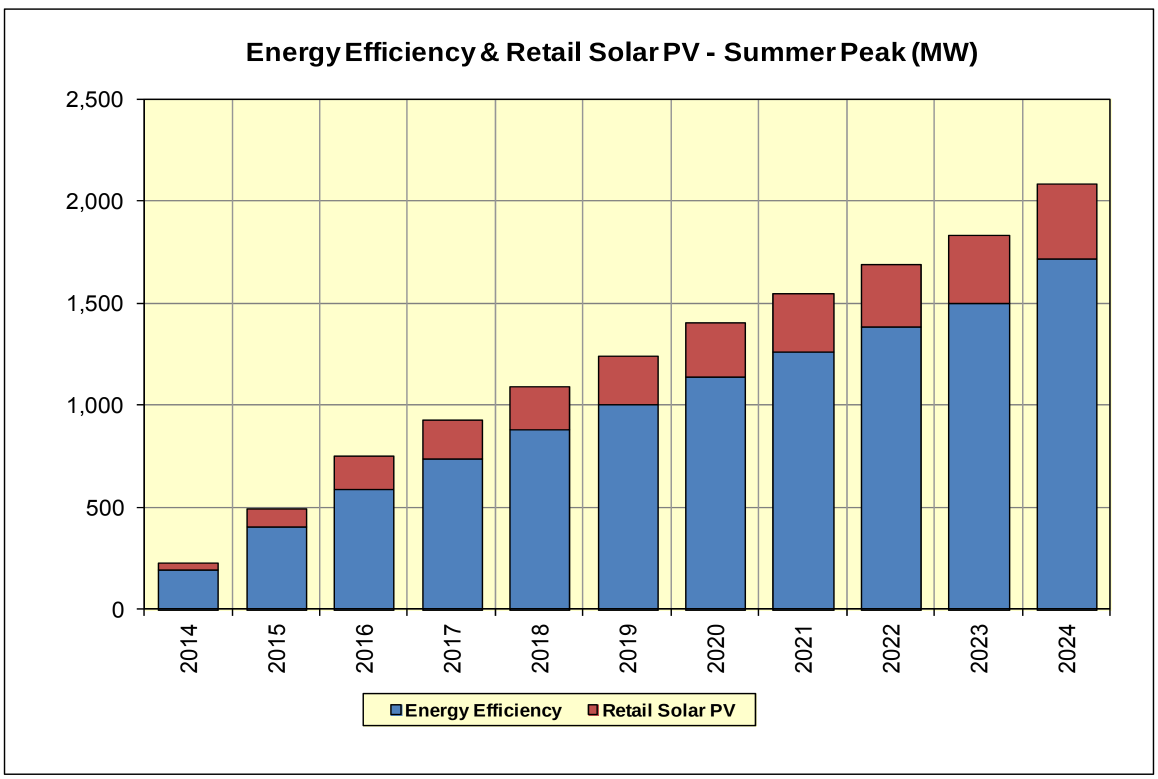


Figure 3-4: 2014 Base Case Energy Efficiency & Retail Solar PV – Summer Peak

3.2. **Forecast of Special Case Resources**

The 2014 RNA special case resource (SCR) levels are based on the 2014 Gold Book value of 1,189 MW. The MARS program used for resource adequacy analysis calculates the SCR values for each hour based on the ratio of hourly load to peak load. Transmission security analysis, which evaluates normal transfer criteria, does not consider SCRs.

3.3. **Resource Additions and Removal**

Since the 2012 RNA, resources have been added to the system, some mothball notices have been withdrawn and the associated facilities have returned to the system and some resources have been removed. A total of 455.9 MW have been added to the 2014 RNA base case either as new generation or existing units returning to service. Meanwhile, a total of 1,368.8 MW have been removed from the 2012 RNA base case because these units have retired, mothballed, or proposed to retire/mothball. The comparison of generation status between the 2012 RNA and 2014 RNA is detailed in Table 3-3 below. The MW values represent the Capacity Resources Interconnection Service (CRIS) MW values as shown in the 2014 Gold Book.

Table 3-3: Generation Addition and Removal

Station Unit	Zone	CRIS (MW)	2012 RNA Status*	2014 RNA Status*
Resource Addition				
Stony Creek Wind	C	93.9	N/A	I/S since Nov. 2013
Taylor Biomass	G	19.0	N/A	I/S starting Dec. 2015
Astoria GT 10	J	24.9	O/S	I/S return to service since July 15, 2013
Astoria GT 11	J	23.6	O/S	I/S return to service since July 15, 2013
Gowanus 1	J	154.4	O/S	I/S (Intent to Retire Notice withdrawn)
Gowanus 4	J	140.1	O/S	I/S (Intent to Retire Notice withdrawn)
Total Resource Addition (CRIS MW)		**455.9**		
Resource Removal				
Dunkirk 2	A	97.2	O/S	I/S until May, 31 2015
RG&E Station 9	B	14.3	I/S	O/S
Seneca Oswego Fulton 1	C	0.7	I/S	O/S
Seneca Oswego Fulton 2	C	0.3	I/S	O/S
Syracuse Energy ST1	C	11.0	I/S	O/S
Syracuse Energy ST2	C	58.9	I/S	O/S
Cayuga 1	C	154.1	I/S	I/S until June 30 2017
Cayuga 2	C	154.1	I/S	I/S until June 30 2017
Chateaugay Power	D	18.2	I/S	O/S
Selkirk-I	F	76.1	I/S	O/S, Intent to Mothball Notice issued in Feb. 2014**
Selkirk-II	F	271.6	I/S	O/S, Intent to Mothball Notice issued in Feb. 2014**
Danskammer 1	G	61.0	I/S	O/S, Intent to Retire Notice issued in Jan. 2013***
Danskammer 2	G	59.2	I/S	O/S, Intent to Retire Notice issued in Jan. 2013***
Danskammer 3	G	137.2	I/S	O/S, Intent to Retire Notice issued in Jan. 2013***
Danskammer 4	G	236.2	I/S	O/S, Intent to Retire Notice issued in Jan. 2013***
Danskammer 5	G	0.0	I/S	O/S, Intent to Retire Notice issued in Jan. 2013***
Danskammer 6	G	0.0	I/S	O/S, Intent to Retire Notice issued in Jan. 2013***
Ravenswood 07	J	12.7	I/S	O/S
Montauk 2, 3, 4	K	6.0	I/S	O/S
Total Resource Removal (CRIS MW)		**1368.8**		

* I/S for In-Service, and O/S for Out-of-Service

** Following the completion of this RNA report, Selkirk Cogen Partners, in a letter dated Sept 3, 2014, withdrew their earlier notice of intent to mothball Selkirk Units 1 & 2.

***On June 27, 2014, the PSC approved the transfer of the Danskammer facility to Helios Power Capital, LLC, and Mercuria Energy America, Inc. Following the transfer, the owners have stated their intent to return the Danskammer facility to operation.

3.4. **Local Transmission Plans**

As part of the Local Transmission Planning Process (LTPP), Transmission Owners presented their Local Transmission Plans (LTPs) to the NYISO and Stakeholders in the fall of 2013. The NYISO reviewed the LTPs and included them in the 2014 Gold Book. The firm transmission plans included in the 2014 RNA base case are reported in Appendix D. Assumptions for inclusion in the RNA were based on data as of April 1, 2014.

3.5. **Bulk Transmission Projects**

Since the 2012 RNA some additional transmission projects have met the inclusion rules and are in the 2014 RNA base case. The National Grid Five Mile Road project includes tapping the Homer City-Stolle Rd. 345 kV circuit and connecting to a new 115 kV station through one 345/115 kV transformer. The National Grid Eastover Rd. project consists of tapping the Rotterdam-Bear Swamp 230 kV circuit and connecting to a new 115 kV station with two 230/115 kV transformers (one spare). These projects are modeled as in-service by summer of 2015.

The Transmission Owner Transmission Solutions (TOTS) is a group of projects by NYPA, NYSEG, and ConEdison that includes three primary projects. The first is Marcy South Series Compensation, which includes the installation of series capacitance at the Marcy station on the Marcy-Coopers Corners 345 kV circuit, and at Fraser station on the Edic-Fraser 345 kV and the Fraser-Coopers Corners 345 kV circuits. A section of the Fraser-Coopers Corners 345 kV circuit will also be reconductored. The second project is Rock Tavern-Ramapo, which includes building an additional 345 kV circuit between Rock Tavern and Ramapo and a 345/138 kV tap connecting to the existing Sugarloaf 138 kV station. The third project is Staten Island Unbottling, which includes the reconfiguration of Goethals and Linden CoGen substations as well as the installation of additional cooling on the 345 kV cables from Goethals to Gowanus and Gowanus to Farragut. The TOTS projects are scheduled to be completed by summer of 2016.

An additional 345/115 kV transformer is modeled as in-service at the NYSEG Wood Street station by the summer of 2016. An additional 230/115/34.5 kV transformer will also be installed at the NYSEG Gardenville substation by the summer of 2017.

The RGE Station 255 project that taps the existing Somerset-Rochester and Niagara-Rochester 345 kV circuits is in the 2014 RNA base case. An additional 345 kV line will be added from Station 255 to Station 80. Station 255 will have two 345/115 kV transformers connecting to a new 115kV station in the Rochester area. These projects, collectively known as the Rochester Area Reliability Project, are modeled as in-service by 2017. Also since the 2012 RNA, two 345/115 kV transformers (T1 and T3) located at RGE Station 80 have been replaced with transformers which have higher ratings, and are modeled accordingly in the 2014 RNA base case.

During the development of the 2012 CRP, National Grid proposed a project to mitigate potential overloads around the Clay substation by reconductoring the Clay-Teall (#10) 115 kV circuit by winter 2017. This upgrade is modeled as part of the 2014 RNA base case starting in the year 2018.

Two FirstEnergy projects within Pennsylvania that tap NYSEG transmission lines are included in the 2014 RNA base case: the Farmers Valley project, which taps the Homer City-Five Mile Rd. 345 kV tie-line, and the Mainesburg project, which taps the Homer City-Watercure 345 kV tie-line. Both projects are modeled as in-service for summer 2015.

3.6. Base Case Peak Load and Resource Ratios

The capacity used for the 2014 RNA base case peak load and resource ratio is the existing generation adjusted for the unit retirements, mothballing, or proposals to retire/mothball announced as of April 15, 2014 along with the new resource additions that met the base case inclusion rules reported in the 2014 Gold Book. This capacity is summarized in Table 3-4 below.

Table 3-4: NYCA Peak Load and Resource Ratios 2015 through 2024

	Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Peak Load (MW)											
	NYCA*	34,066	34,412	34,766	35,111	35,454	35,656	35,890	36,127	36,369	36,580
	Zone J*	12,050	12,215	12,385	12,570	12,700	12,790	12,900	12,990	13,100	13,185
	Zone K*	5,543	5,588	5,629	5,668	5,708	5,748	5,789	5,831	5,879	5,923
	Zone G-J	16,557	16,749	16,935	17,149	17,311	17,421	17,554	17,694	17,828	17,935
Resources (MW)											
	Capacity**	37,375	37,394	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
	Net Purchases & Sales	2,237	2,237	2,237	2,237	2,237	2,237	2,237	2,237	2,237	2,237
	SCR	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189
NYCA	Total Resources	**40,801**	**40,820**	**40,511**	**40,511**	**40,511**	**40,511**	**40,511**	**40,511**	**40,511**	**40,511**
	Capacity/Load Ratio	109.7%	108.7%	106.7%	105.6%	104.6%	104.0%	103.3%	102.7%	102.0%	101.4%
	Cap+NetPurch/Load Rati	116.3%	115.2%	113.1%	112.0%	110.9%	110.3%	109.6%	108.8%	108.1%	107.5%
	Tot.Res./Load Ratio	119.8%	118.6%	116.5%	115.4%	114.3%	113.6%	112.9%	112.1%	111.4%	110.7%
Zone J	Total Resources	**10,797**	**10,797**	**10,797**	**10,797**	**10,797**	**10,797**	**10,797**	**10,797**	**10,797**	**10,797**
	Tot.Res./Load Ratio	89.6%	88.4%	87.2%	85.9%	85.0%	84.4%	83.7%	83.1%	82.4%	81.9%
Zone K	Total Resources	**6,360**	**6,360**	**6,360**	**6,360**	**6,360**	**6,360**	**6,360**	**6,360**	**6,360**	**6,360**
	Tot.Res./Load Ratio	114.7%	113.8%	113.0%	112.2%	111.4%	110.6%	109.9%	109.1%	108.2%	107.4%
Zone G-J	Total Resources	15,137	15,137	15,137	15,137	15,137	15,137	15,137	15,137	15,137	15,137
	Tot.Res./Load Ratio	91.4%	90.4%	89.4%	88.3%	87.4%	86.9%	86.2%	85.5%	84.9%	84.4%

*NYCA load values represent baseline coincident summer peak demand. Zones J and K load values represent non-coincident summer peak demand. Aggregate Zones G-J values represent G-J coincident peak, which is non-coincident with NYCA.

**NYCA Capacity values include resources electrically internal to NYCA, additions, reratings, and retirements (including proposed retirements and mothballs). Capacity values reflect the lesser of CRIS and DMNC values. NYCA resources include the net purchases and sales as per the Gold Book. Zonal totals include the awarded UDRs for those capacity zones.

Notes:

- SCR - Forecasted ICAP value based on 2014 Gold Book.
- Wind generator summer capacity is counted as 100% of nameplate rating.
- The NYISO set a deadline of May 15, 2014 for deciding whether to include Dunkirk fuel conversion project in the base case or to study it separately as a sensitivity. The NYISO subsequently determined to study it separately as a sensitivity.

For summer 2014 resource adequacy, the existing capacity provides about a 122.7% Installed Capacity Reserve to meet the summer 2014 Installed Reserve Margin requirement of 117.0%. The capacity margin decreases throughout the study period, but more rapidly and noticeably in the outer years due to load growth. Consequently, the reliability need year has advanced to 2019. To demonstrate the significant reduction in resources, the NYISO compared the capacity margin in the need year of 2019 between the 2012 RNA and the 2014 RNA. The NYISO found a net capacity margin decrease of 2,100 MW, which breaks down as follows, and summarized in Table 3-5:

1. The NYCA capacity resources are 874 MW less for 2019 (724 MW upstate and 150 MW in SENY);
2. The NYCA baseline load forecast is 250 MW higher for 2019 (497 MW higher upstate and 247 MW lower in SENY); and
3. The NYCA Special Case Resources (SCRs) projection is 976 MW less for 2019 (685 MW upstate and 291 MW in SENY).

This reduction contributes to the shift of the need year from 2020 to 2019 identified in the 2014 RNA, and discussed in Section 4.

Table 3-5: Load/Resources Comparison of Year 2019 (MW)

Year 2019	2012 RNA	2014 RNA	delta
Load	35,204	35,454	250
SCR	2,165	1,189	-976
Total Capacity without SCRs	40,196	39,322	-874
Net Change in capacity margin in 2014 RNA from 2012 RNA (MW)			-2,100

3.7. Methodology for the Determination of Needs

Reliability Needs are defined by the Open Access Transmission Tariff (OATT) in terms of total deficiencies relative to Reliability Criteria determined from the assessments of the BPTFs performed for the RNA. There are two steps to analyzing the reliability of the BPTFs. The first is to evaluate the security of the transmission system; the second is to evaluate the adequacy of the system, subject to the security constraints. The NYISO planning procedures include both security and adequacy assessments. The transmission adequacy and the resource adequacy assessments are performed together.

Transmission security is the ability of the power system to withstand disturbances such as short circuits or unanticipated loss of system elements and continue to supply and deliver electricity. Security is assessed deterministically, with potential disturbances being applied without concern for the likelihood of the disturbance in the assessment. These disturbances (single-element and multiple-element contingencies) are categorized as the design criteria contingencies, explicitly defined in the NYSRC Reliability Rules. The impacts when applying these design criteria contingencies are assessed to ensure no thermal loading, voltage or stability violations will occur. In addition, the NYISO performs a short circuit analysis to determine if the system can clear faulted facilities reliably under short circuit conditions. The NYISO “Guideline for Fault Current Assessment” describes the methodology for that analysis.

The analysis for the transmission security assessment is conducted in accordance with NERC Reliability Standards, NPCC Transmission Design Criteria, and the NYSRC Reliability Rules. AC contingency analysis is performed on the BPTF to evaluate thermal and voltage performance under design contingency conditions using the Siemens PTI PSS®E and PowerGEM TARA programs. Generation is dispatched to match load plus system losses, while respecting transmission security. Scheduled inter-area transfers modeled in the base case between the NYCA and neighboring systems are held constant.

For the RNA, approximately 1,000 design criteria contingencies are evaluated under N-1, N-1-0, and N-1-1 normal transfer criteria conditions to ensure that the system is planned to meet all applicable reliability criteria. To evaluate the impact of a single event from the normal system condition (N-1), all design criteria contingencies are evaluated including: single element, common structure, stuck breaker, generator, bus, and HVDC facilities contingencies. An N-1 violation occurs when the power flow on the monitored facility is greater than the applicable post-contingency rating. N-1-0 and N-1-1 analysis evaluates the ability of the system to meet design criteria after a critical element has already been lost. For N-1-0 and N-1-1 analysis, single element contingencies are evaluated as the first contingency; the second contingency (N-1-1) includes all design criteria contingencies evaluated under N-1 conditions.

The process of N-1-0 and N-1-1 testing allows for corrective actions including generator redispatch, phase angle regulator (PAR) adjustments, and HVDC adjustments between the first and second contingency. These corrective actions prepare the system for the next contingency by reducing the flow to normal rating after the first contingency. An N-1-0 violation occurs when the flow cannot be reduced to below the normal rating following the first contingency. An N-1-1 violation occurs when the facility is reduced to below the normal rating following the first contingency, but the power flow following the second contingency is greater than the applicable post-contingency rating.

Resource adequacy is the ability of the electric systems to supply the aggregate electricity demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system elements. Resource adequacy considers the transmission systems, generation resources, and other capacity resources, such as demand response. Resource adequacy assessments are performed on a probabilistic basis to capture the random natures of system element outages. If a system has sufficient transmission and generation, the probability of an unplanned disconnection of firm load is equal to or less than the system’s standard, which is expressed as a Loss of Load Expectation (LOLE). The New York

State bulk power system is planned to meet a LOLE that, at any given point in time, is less than or equal to an involuntary load disconnection that is not more frequent than once in every 10 years, or 0.1 events per year. This requirement forms the basis of New York's Installed Reserve Margin (IRM) requirement and is on a statewide basis.

If Reliability Needs are identified, various amounts and locations of compensatory MW required for the NYCA to satisfy those needs are determined to translate the criteria violations to understandable quantities. Compensatory MW amounts are determined by adding generic capacity resources to zones to effectively satisfy the needs. The compensatory MW amounts and locations are based on a review of binding transmission constraints and zonal LOLE determinations in an iterative process to determine various combinations that will result in Reliability Criteria being met. These additions are used to estimate the amount of resources generally needed to satisfy Reliability Needs. The compensatory MW additions are not intended to represent specific proposed solutions. Resource needs could potentially be met by other combinations of resources in other areas including generation, transmission and demand response measures.

Due to the differing natures of supply and demand-side resources and transmission constraints, the amounts and locations of resources necessary to match the level of compensatory MW needs identified will vary. Resource needs could be met in part by transmission system reconfigurations that increase transfer limits, or by changes in operating protocols. Operating protocols could include such actions as using dynamic ratings for certain facilities, invoking operating exceptions, or establishing special protection systems.

The procedure to quantify compensatory MW for BPTF transmission security violations is a separate process from calculating compensatory MW for resource adequacy violations. This quantification is performed by first calculating transfer distribution factors (TDF) on the overloaded facilities. The power transfer used for this calculation is created by injecting power at existing buses within the zone where the violation occurs, and reducing power at an aggregate of existing generators outside of the area.

4. Reliability Needs Assessment

4.1. **Overview**

Reliability is defined and measured through the use of the concepts of security and adequacy described in Section 3.

4.2. **Reliability Needs for Base Case**

Below are the principal findings of the 2014 RNA applicable to the base case conditions for the 2015-2024 study periods including: transmission security assessment; short circuit assessment; resource and transmission adequacy assessment; system stability assessments; and scenario analyses.

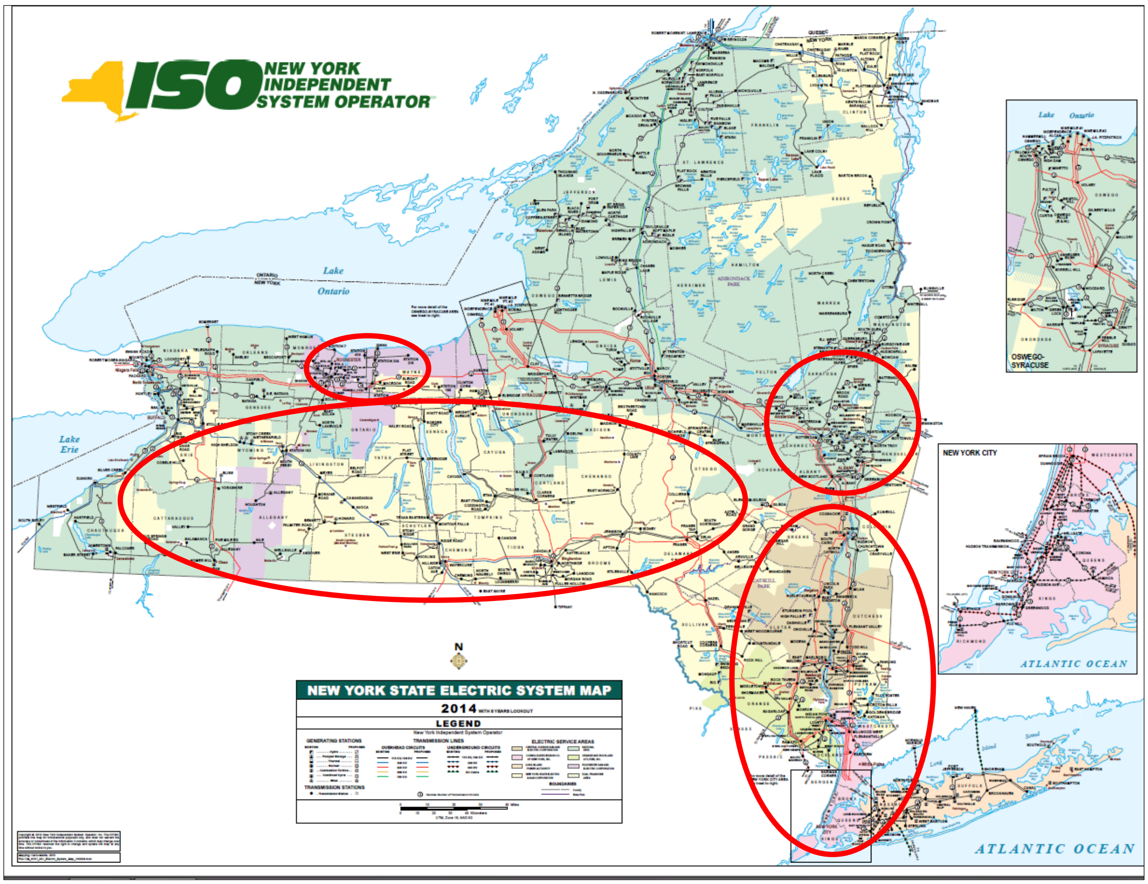
4.2.1. Transmission Security Assessment

The RNA requires analysis of the security of the Bulk Power Transmission Facilities (BPTF) throughout the Study Period (2015-2024). The BPTF, as defined in this assessment, include all of the facilities designated by the NYISO as a Bulk Power System (BPS) element as defined by the NYSRC and NPCC, as well as other transmission facilities that are relevant to planning the New York State transmission system. To assist in the assessment, the NYISO reviewed many previously completed transmission security assessments, and utilized the most recent Area Transmission Review and FERC Form 715 power flow case that the NYISO submitted to FERC.

The transmission security analysis identifies thermal violations on the BPTF throughout the Study Period (2015-2024) for N-1, N-1-0, and N-1-1 conditions, some of which are a continuation of the violations identified in the 2012 RNA for which work is ongoing and some of which represent new violations resulting from system changes modeled in the base case. Table 4-1 provides a summary of the contingency pairs that result in the highest thermal overload on each overloaded BPTF element under N-1, N-1-0, and N-1-1 conditions using coincident peak loading. In the second contingency column of Table 4-1, “N/A” corresponds to an N-1 violation and “Base Case” corresponds to an N-1-0 violation. Table 4-2 provides a summary of the year by which a solution is needed to be in-service to mitigate the transmission security violation. Appendix D provides a summary of all contingency pairs that result in overloads on the BPTF for the study period.

There are four primary regions of Reliability Needs identified in Table 4-1 including: Rochester, Western & Central New York, Capital Region, and Lower Hudson Valley & New York City. These Reliability Needs either continue to be generally driven by, or have arisen anew due to, two primary factors: (i) recent and proposed generator retirements/mothballs; and (ii) combined with load growth. Considering non-coincident peak loading for these regions, the overloads listed in Table 4-1 would increase most notably in the out-years. Figure 4-1 geographically depicts the four regions where the loads may be impacted by transmission security constraints.

Figure 4-1: Approximate Locations of Transmission Security Needs



Rochester

The transmission security analysis continues to show near-term overloads in the Rochester area, primarily due to load growth. The 2012 RNA identified overloaded transformers at Station 80 and Pannell starting in 2013. The Station 80 overloads were resolved by the recently completed replacement of two transformers at that station. The remaining portion of the Rochester Area Reliability Project, Rochester Gas and Electric (RG&E) Station 255, which was provided as a solution in the 2012 CRP is included in the base case starting in 2017 according to the firm plans identified in the 2014 Gold Book.

Starting in 2015, the Pannell 345/115 kV transformer 1TR is overloaded for the loss of Ginna followed by a stuck breaker at Pannell. Pannell 345/115 kV transformer 2TR is similarly overloaded for the loss of Ginna followed by a stuck breaker at Pannell. The Pannell-Quaker (#914) 115 kV line overloads for the loss of Ginna followed by a loss of Pannell 345/115 kV 3TR.

The N-1-1 violations on Pannell 345/115 transformers 1TR and 2TR and Pannell-Quaker (#914) 115 kV are resolved after RG&E Station 255 is in-service.

Western & Central New York

The transmission security analysis identifies a number of thermal and voltage violations on the BPTF in the Western and Central New York regions resulting from a lack of transmission and generating resources to serve load and support voltage in the area.

The 230 kV system between Niagara and Gardenville includes two parallel 230 kV transmission lines from Niagara to Packard to Huntley to Gardenville, including a number of taps to serve load in the Buffalo area. A third parallel 230 kV transmission line also runs from Niagara to Robinson Rd. to Stolle Rd. to Gardenville. The N-1-1 analysis shows that in 2018, Huntley-Gardenville (#80) 230 kV overloads for loss of the parallel line (#79) followed by a stuck breaker at the Robinson Road 230 kV substation. In 2021, the Packard-Huntley (#77) and (#78) lines each overload for the loss of the parallel line followed by a stuck breaker at the Robinson Road 230 kV substation. Similarly, in 2022, the Huntley-Gardenville (#79) line overloads for loss of the parallel line (#80) followed by a stuck breaker at the Robinson Road 230 kV substation. The overloads occur due to increased load in Western and Central New York and are aggravated by both the mothball of Dunkirk generation and a new load-serving 230/115 kV substation (Four Mile Junction) just within the PJM area.

National Grid’s Clay 115 kV station includes eight 115 kV transmission connections and two 345/115 kV transformers that serve the Oswego and Syracuse areas. Starting in 2015, the Clay-Lockheed Martin (#14) 115 kV line has a flow of 146 MVA compared to a Long Term Emergency (LTE) rating of 120 MVA for an N-1 breaker failure at the Oswego 345 kV substation. In 2019, the flow increases to 166 MVA. The increase in flow between 2015 and 2019 is primarily due to modeling the Cayuga generation plant out-of-service starting in 2017. The increased load and Dunkirk mothballing in 2015 also contribute to the overload. In 2024, the flow increases to 168 MVA due to load growth. In 2024, the Clay-Woodward (Euclid-Woodard) (#17) 115 kV line has a flow of 183 MVA compared to an LTE rating of 174 MVA due to an N-1 breaker failure at the Lafayette 345 kV substation.

Thermal overloads are also observed at Clay for N-1-1 conditions. Starting in 2015, the N-1-1 analysis shows various overloads in the Syracuse area including: Clay-Lockheed Martin (#14) 115 kV, Clay-Teall (#10) 115 kV, and the Clay-Dewitt (#3) 115 kV line. Starting in 2017, the N-1-1 analysis shows additional overloads on: Clay-Woodard (#17) 115 kV, Clay-S. Oswego (#4) 115 kV, and the Clay 345/115 kV 1TR transformer. In the 2012 RNA, the NYISO identified transmission security violations on Clay-Teall (#10) 115 kV line. The overloads on the Clay-Teall (#10) 115 kV and the Clay-Dewitt (#3) 115 kV lines are mitigated by the solutions identified in the 2012 CRP starting in 2018, as described in Section 3.5 of this report. The Clay-Lockheed Martin (#14) 115 kV line also experiences an N-1-0 violation starting in 2019 for the loss of the Elbridge 345/115 kV transformer. The overloads in this area are primarily due to power flowing from east-to-west on the 115 kV system to serve load in Central New York after the loss of a north-to-south 345 kV path and are exacerbated with Cayuga mothballed.

National Grid's Porter 115 kV station includes eight 115 kV transmission connections and two 345/115 kV transformers that serve the Utica and Syracuse areas. The N-1-1 analysis shows the Porter-Yahnundasis (#3) 115 kV line overloaded starting in 2015 for the loss of Oswego-Elbridge-Lafayette (#17) 345 kV followed by a stuck breaker at the Clay 345 kV substation; additionally, the N-1-1 analysis shows the Porter-Oneida (#7) 115 kV line overloaded starting in 2017 for the same contingency pair. These overloads are due to power flowing from east to west on the 115 kV system to serve load in the Utica, Syracuse, and Finger Lakes area and are exacerbated with Cayuga mothballed.

In addition to the thermal violations identified in Table 4-1, the Porter 115 kV area has local low voltage issues in all years due to a stuck breaker contingency.

The Oakdale 345/230/115 kV substation serves the Binghamton area. Starting in 2015, N-1-1 analysis shows the loading on Oakdale 345/115 kV 2TR is overloaded for the loss of Watercure 345/230 kV 1TR followed by a stuck breaker at Oakdale 345 kV; however, starting in 2016 a second Watercure 345/230 kV transformer (expected in-service date prior to winter 2015) is modeled in-service, which resolves Watercure 345/230 kV transformer from being a limiting contingency. With the second Watercure 345/230 kV transformer in-service in 2016, the limiting contingency pair changes to the loss of Fraser 345/115 kV 2TR followed by a stuck breaker at Oakdale 345 kV. An N-1-0 violation occurs starting in 2016 on Oakdale 345/115 kV 2TR for loss of Oakdale 345/115 kV 3TR and then in 2020 on Oakdale 345/115 kV 3TR for loss of Oakdale 345/115 kV 2TR. The overloads on the Oakdale 345/115 kV transformers are caused by the loss of sources (i.e. transformers) and are exacerbated with Cayuga mothballed.

In addition to the thermal violations identified in Table 4-1, the Oakdale area has low voltage under N-1-1 conditions starting in 2017 for loss of transformer sources into the local area from the bulk system. The low voltage is primarily due to modeling the Cayuga generation plant out-of-service starting in 2017.

Capital Region

In March of 2014, Selkirk Cogen Partners, LLC submitted their notice of intent to mothball the Selkirk I and Selkirk II facilities effective September 2014; therefore, these generating units are not included in the base case. With the Selkirk plant modeled out-of-service, pre-contingency overloads exist on local 115 kV non-BPTF elements beginning in 2015 and, unless resolved, continuing for all study years. There are also significant post-contingency overloads on the local 115 kV transmission lines. Additionally, overloads are noted on the New Scotland 345/115 kV transformer for the loss of generation at Bethlehem followed by loss of a New Scotland 345 kV bus (#77) and the Reynolds 345/115 kV transformer has an N-1-0 violation for the loss of generation at Bethlehem. National Grid is evaluating the overloaded local facilities in this area and determining corrective action plans. The solutions developed by National Grid will impact the magnitude of loadings on BPTF facilities in the Capital Region. These loadings on the BPTF facilities will be reevaluated as part of the CRP following National Grid's update to their local transmission plan.

Lower Hudson Valley & New York City

The UPNY-SENY interface includes five 345 kV lines from north to south within New York: Leeds – Athens – Pleasant Valley (#95/91) 345 kV, Leeds – Pleasant Valley (#92) 345 kV, Leeds – Hurley (#301) 345 kV, Coopers Corners – Rock Tavern (#42) 345 kV, and Coopers Corners – Middletown – Rock Tavern (#34) 345 kV. Similar to the 2012 RNA, the Leeds – Pleasant Valley lines are overloaded starting in 2022 for the N-1-1 loss of other 345 kV lines across the UPNY-SENY interface. These overloads are due to load growth and a reduction in generation in the Lower Hudson Valley and New York City areas.

Table 4-1: 2014 RNA Transmission Security Thermal Violations

Zone	Owner	Monitored Element	Normal Rating (MVA)	LTE Rating (MVA)	STE Rating (MVA)	2015 Flow (MVA)	2019 Flow (MVA)	2024 Flow (MVA)	First Contingency	Second Contingency
A	N.Grid	Packard-Huntley (#77) 230 (Packard-Sawyer)	556	644	704			649	Packard-Huntley (#78) 230	SB Robinson Rd 230
A	N.Grid	Packard-Huntley (#78) 230 (Packard-Sawyer)	556	644	746			649	Packard-Huntley (#77) 230	SB Robinson Rd 230
A	N.Grid	Huntley-Gardenville (#79) 230 (Huntley-Sawyer)	566	654	755			664	Huntley-Gardenville (#80) 230	SB Robinson Rd 230
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755		661	672	Huntley-Gardenville (#79) 230	SB Robinson Rd 230
								697	Robinson-Stolle Rd (#65) 230	Huntley-Gardenville (#79) 230
B	RGE	Pannell 345/115 1TR	228	282	336	372			L/O Ginna	SB Pannell 345
B	RGE	Pannell 345/115 2TR	228	282	336	372			L/O Ginna	SB Pannell 345
B	RGE	Pannell-Quaker (#914) 115	207.1	246.9	284.8	298			L/O Ginna	Pannell 345/115 3TR
C	NYSEG	Oakdale 345/115 2TR	428	556	600	573			Watercure 345/230 1TR	SB Oakdale 345
							440	444	Oakdale 345/115 3TR	Base Case
							574	586	Fraser 345/115 2TR	SB Oakdale 345
C	NYSEG	Oakdale 345/115 3TR	428	556	600			438	Oakdale 345/115 2TR	Base Case
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	146	163	168	SB Oswego 345	N/A
							139	142	Elbridge 345/115 1TR	Base Case
						165	204	216	Clay-Woodard (#17) 115	SB Lafayette 345
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	116	120	145	131			Clay-Teall (#11) 115	SB Dewitt 345
C	N.Grid	Clay-Dewitt (#3) 115 (Clay-Bartell Rd)	116	120	145	126			Clay-Dewitt (#13) 345	SB Oswego 345
C	N.Grid	Clay 345/115 1TR	478	637	794		710	757	Oswego-Elbridge-Lafayette (#17) 345	SB Clay 345
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174			183	SB Lafayette 345	N/A
							207	220	Clay-Lockheed Martin (#14) 115	SB Lafayette 345
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	104	104	104		114	117	Clay 345/115 1TR	SB Clay 345
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	128	141	142	Oswego-Elbridge-Lafayette (#17) 345	SB Clay 345
								143	Clay-Dewitt (#13) 345	SB Oswego 345
E	N.Grid	Porter-Oneida (#7) 115 (Porter-W. Utica)	116	120	145		122	125	Oswego-Elbridge-Lafayette (#17) 345	SB Clay 345
								126	Clay-Dewitt (#13) 345	SB Oswego 345
F	N.Grid	New Scotland 345/115 1TR	458	570	731	631	659	837	L/O Bethlehem	New Scotland (#77) 345
F	N.Grid	Reynolds 345/115	459	562	755	492	498	584	L/O Bethlehem	Base Case
F-G	N.Grid	Leeds-Pleasant Valley (#92) 345	1331	1538	1724			1587	Athens-Pleasant Valley (#91) 345	Tower 41&33
F-G	N.Grid	Athens-Pleasant Valley (#91) 345	1331	1538	1724			1584	Leeds-Pleasant Valley (#92) 345	Tower 41&33

Table 4-2: 2014 RNA Transmission Security Reliability Need Year

Zone	Owner	Monitored Element	Year of Need
B	RGE	Pannell 345/115 1TR	2015
B	RGE	Pannell 345/115 2TR	2015
B	RGE	Pannell-Quaker (#914) 115	2015
C	NYSEG	Oakdale 345/115 2TR	2015
C	N.Grid	Clay-Lockheed Martin (#14) 115	2015
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	2015
C	N.Grid	Clay-Dewitt (#3) 115 (Clay-Bartell Rd)	2015
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	2015
F	N.Grid	New Scotland 345/115 1TR	2015
F	N.Grid	Reynolds 345/115	2015
C	N.Grid	Clay 345/115 1TR	2017
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	2017
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	2017
E	N.Grid	Porter-Oneida (#7) 115 (Porter-W. Utica)	2017
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	2018
C	NYSEG	Oakdale 345/115 3TR	2020
A	N.Grid	Packard-Huntley (#77) 230 (Packard-Sawyer)	2021
A	N.Grid	Packard-Huntley (#78) 230 (Packard-Sawyer)	2021
A	N.Grid	Huntley-Gardenville (#79) 230 (Huntley-Sawyer)	2022
F – G	N.Grid	Leeds-Pleasant Valley (#92) 345	2022
F – G	N.Grid	Athens-Pleasant Valley (#91) 345	2022

4.2.2. Short Circuit Assessment

Performance of a transmission security assessment includes the calculation of symmetrical short circuit current to ascertain whether the circuit breakers in the system could be subject to fault current levels in excess of their rated interrupting capability. The analysis was performed for the year 2019 reflecting the study conditions outlined in Section 3. The calculated fault levels would be constant over the second five years because no new generation or transmission is modeled in the RNA for second five years, and the methodology for fault duty calculation is not sensitive to load growth. The detailed results are presented in Appendix D of this report.

National Grid, having taken into account factors such as circuit breaker age and fault current asymmetry, has derated breakers at certain stations. As a result, overdutied breakers were identified at Porter 230 kV and Porter 115 kV stations. Table 4-3: summarizes over-duty breakers at each station. National Grid reports that plans to make the necessary facility upgrades are in place. For Porter 115 kV, National Grid is scheduled to rebuild the station and replace all the breakers by Winter 2014/2015. For Porter 230 kV, National Grid is scheduled to add microprocessor relays to mitigate the overdutied breakers by the end of 2014.

Table 4-3:2014 RNA Over-Duty Circuit Breaker Summary

Substation	**kV**	**Number of Over-Duty Circuit Breakers**	**Breaker ID**
Porter	115	10	R130, R10, R20, R30, R40, R50, R60, R70, R80, R90
Porter	230	9	R110,R120,R15, R170, R25, R320, R835, R825, R845

4.2.3. Transmission and Resource Adequacy Assessment

The NYISO conducts its resource adequacy analysis with General Electric's Multi Area Reliability Simulation (MARS) software package. The modeling applies interface transfer limits and performs a probabilistic simulation of outages of capacity and transmission resources.

The emergency transfer limits were developed using the 2014 RNA base case. Table 4-4, Table 4-5, and Table 4-6 below provide the thermal and voltage emergency transfer limits for the major NYCA interfaces. For comparison purposes, the 2012 RNA transfer limits are presented.

Table 4-4: Transmission System Thermal Emergency Transfer Limits

Interface	2014 RNA study						2012 RNA study		
	2015	2016	2017	2018	2019	2024	2015	2016	2017
Dysinger East	2200	2150	2100	2075	2050	Same as 2019	2975	2975	2975
Central East MARS	4025	4500	4500	4500	4500	Same as 2019	3425	3425	3475
E to G (Marcy South)	1700	2150	2150	2150	2150	Same as 2019	1700	1700	1700
F to G	3475	3475	3475	3475	3475	Same as 2019	3475	3475	3475
UPNY-SENY MARS	5150	5600	5600	5600	5600	Same as 2019	5150	5150	5150
I to J (Dunwoodie South MARS)	4400	4400	4400	4400	4400	Same as 2019	4400	4400	4400
I to K (Y49/Y50)	1290	1290	1290	1290	1290	Same as 2019	1290	1290	1290

Table 4-5: Transmission System Voltage Emergency Transfer Limits

Interface	2014 RNA study						2012 RNA study		
	2015	2016	2017	2018	2019	2024	2015	2016	2017
Dysinger East	2700	DNC	DNC	DNC	2800	Same as 2019	2875	2900	2875
West Central	1475	DNC	DNC	DNC	1350	Same as 2019	1850	1900	1900
Central East MARS	3250	3100	3100	3100	3100	Same as 2019	3350	3350	3350
Central East Group	4800	5000	5000	5000	5000	Same as 2019	4800	4800	4800
UPNY-ConEd	5210	5210	5210	5210	5210	Same as 2019	5210	5210	5210
I to J & K	5160	5160	5160	5160	5160	Same as 2019	5160	5160	5160

DNC: Did Not Calculate

Table 4-6: Transmission System Base Case Emergency Transfer Limits

Interface	2014 RNA study											2012 RNA study					
	2015		2016		2017		2018		2019		2024	2015		2016		2017	
Dysinger East	2200	T	2150	T	2100	T	2075	T	2050	T	Same as 2019	2875	V	2900	V	2875	V
Central East MARS	3250	V	3100	V	3100	V	3100	V	3100	V	Same as 2019	3350	V	3350	V	3350	V
Central East Group	4800	V	5000	V	5000	V	5000	V	5000	V	Same as 2019	4800	V	4800	V	4800	V
E to G (Marcy South)	1700	T	2150	T	2150	T	2150	T	2150	T	Same as 2019	1700	T	1700	T	1700	T
F to G	3475	T	3475	T	3475	T	3475	T	3475	T	Same as 2019	3475	T	3475	T	3475	T
UPNY-SENY MARS	5150	T	5600	T	5600	T	5600	T	5600	T	Same as 2019	5150	T	5150	T	5150	T
I to J (Dunwoodie South MARS)	4400	T	4400	T	4400	T	4400	T	4400	T	Same as 2019	4400	T	4400	T	4400	T
I to K (Y49/Y50)	1290	T	1290	T	1290	T	1290	T	1290	T	Same as 2019	1290	T	1290	T	1290	T
I to J & K	5160	C	5160	C	5160	C	5160	C	5160	C	Same as 2019	5160	C	5160	C	5160	C

Note: T=Thermal, V=Voltage, C=Combined

The Dysinger East transfer limit decreased compared to the transfer limit used in the 2012 RNA. The thermal limitations on the 230 kV transmission path between Packard and Gardenville in Zone A became more constraining than the voltage limitations. This was due primarily to modeling the Dunkirk plant as out-of-service in the 2014 RNA analysis whereas, in contrast, there was 500 MW of generic generation modeled at the Dunkirk substation for the calculation of transfer limits in the 2012 RNA. The transfer limit further reduces incrementally each year due to load growth in Zone A.

The Central East MARS interface limit is lower for the 2014 RNA than it was for the 2012 RNA. This is primarily due to the inclusion of the Transmission Owner Transmission Solutions (TOTS) projects. The inclusion of the TOTS projects in the model also resulted in increases to the Central East Group, Marcy South, and UPNY-SENY MARS interface transfer limits. The TOTS projects that add series compensation to the Marcy South transmission corridor effectively increase flow through that transmission path. The second Rock Tavern-Ramapo 345 kV line also contributes to this change in the power flow pattern. The result is that power is diverted somewhat from the circuits that make up the Central East MARS interface and the power flow across the UPNY-SENY interface is more balanced between the Marcy South corridor and the Leeds-Pleasant Valley corridor. Inclusion of the TOTS projects also impacts the A line and VFT interface(Staten Island) by significantly reducing the constraints on flows from Staten Island generation and the ties to New Jersey.

The results of the 2014 RNA base case studies show that the LOLE for the NYCA exceeds 0.1 beginning in the year 2019 and the LOLE continues to increase through 2024[2]. The LOLE results for the entire 10-year RNA base case are presented in Table 4-7. While the LOLE criteria are evaluated on a statewide basis, both the NYCA and zonal LOLE are presented for informational purposes to assist in the development of the compensatory MWs. The zonal LOLE are driven by many factors and thus cannot be used for direct identification of the drivers of the statewide LOLE violations. A test to determine the causation of the LOLE separation on a zonal basis caused by transmission interface constraints was developed and applied to identify those interfaces most binding at the time of NYCA LOLE event. It is referred to as the Binding Interface test and it is critical in developing the most effective compensatory MW locations. Consistent with the previous RNAs, UPNY-SENY remains the most constraining interface.

[2] RNA Study results are rounded to two decimal places. A result of exactly 0.01, for example, would correspond to one event in one hundred years.

Table 4-7: NYCA Resource Adequacy Measure (in LOLE)

Zone(s)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Zone A	0	0	0	0	0	0	0	0	0	0
Zone B	0.02	0.02	0.04	0.05	0.06	0.06	0.07	0.08	0.08	0.09
Zone C	0	0	0	0	0	0	0	0	0	0
Zone D	0	0	0	0	0	0	0	0	0	0
Zone E	0.02	0.02	0.04	0.05	0.06	0.06	0.07	0.08	0.08	0.09
Zone F	0	0	0	0	0	0	0	0	0	0
Zones A-F	0.02	0.02	0.04	0.05	0.06	0.06	0.07	0.08	0.08	0.09
Zone G	0.01	0.01	0.02	0.03	0.04	0.04	0.05	0.06	0.07	0.08
Zone H	0	0	0	0	0	0	0	0	0	0
Zone I	0.04	0.04	0.06	0.08	0.11	0.13	0.15	0.18	0.22	0.25
Zone J	0.04	0.04	0.06	0.08	0.10	0.12	0.15	0.18	0.21	0.25
Zone K	0.01	0.02	0.03	0.04	0.06	0.07	0.09	0.12	0.15	0.19
Zones G-K	0.04	0.04	0.06	0.08	0.11	0.13	0.15	0.18	0.22	0.26
NYCA	0.04	0.04	0.06	0.08	0.11	0.13	0.15	0.18	0.22	0.26

*Note: "0" represents an LOLE less or equal to 0.004.

In order to avoid over-dependence on emergency assistance from external areas, emergency operating procedures in the external areas are not modeled. Capacity of the external systems is further adjusted so that the interconnected LOLE value of the external areas (Ontario, New England, Hydro Quebec, and PJM) is not less than 0.10 and not greater than 0.15 for the year 2015. The level of load and generation are frozen in the remaining years. The LOLE for the external systems will generally increase consistent with the increase in NYCA LOLE which results from the load growth over the Study Period. The increase is higher than in previous RNAs because of the increased binding on Dysinger East and Central East Group.

4.2.4. System Stability Assessment

The 2010 NYISO Comprehensive Area Transmission Review (CATR), which was completed in June 2011 and evaluated the year 2015, is the most recent CATR. The 2013 NYISO Intermediate Area Transmission Review evaluated the year 2018 and was completed in June 2014. The stability analyses conducted as part of the 2010 and 2013 ATRs in conformance with the applicable NERC standards, NPCC criteria, and NYSRC Reliability Rules found no stability issues (criteria violations) for summer peak load and light load conditions.

4.3. **Reliability Needs Summary**

After determining that the LOLE criterion would be violated beginning in 2019 and continuing through 2024, the LOLE for the bulk power system for those years was calculated with two additional cases. The first is NYCA Thermal with all NYCA internal transfer limits set at thermal (not voltage) limits to determine whether the system was adequate to deliver generation to the loads without the voltage constraints. The second is the NYCA free flow, which was performed with all NYCA internal transfer limits removed. Table 4-8 presents a summary of the results.

Table 4-8: Summary of the LOLE Results – Base, Thermal, and Free Flow Cases

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
NYCA	0.04	0.04	0.06	0.08	0.11	0.13	0.15	0.18	0.22	0.26
NYCA Thermal	0.04	0.04	0.06	0.08	0.11	0.13	0.15	0.18	0.22	0.26
NYCA FreeFlow					0.07	0.07	0.07	0.08	0.08	0.09

In general, an LOLE result above 0.1 days per year indicates that additional resources are required to maintain reliability (adequacy). The results indicate the first year of need for resources (a Reliability Need) is 2019 for the RNA base case. The Reliability Needs can be resolved by adding capacity resources downstream of the transmission constraints or by adding transmission reinforcement to mitigate the constraints.

To determine if transmission reinforcements would be beneficial, the “NYCA Thermal” and a “NYCA Free Flow Test” cases are executed. The first year of need for the free flow sensitivity case is beyond 2024, which means that there is no statewide deficiency, and transmission reinforcement is a potential option to resolving the LOLE violation. In addition, the NYCA Thermal case results indicate that voltage limits are not constraining enough to impact NYCA LOLE.

Additional analysis of the base case results to determine binding hours showed that UPNY-SENY remains among the most constraining interfaces, consistent with the conclusion from the previous RNAs. This indicates that increasing the total resources downstream of UPNY-SENY or increasing the UPNY-SENY transfer limit will be among the most effective options to resolve the LOLE violations. Another aspect of the binding hours determination is to perform a relaxation by increasing the individual constraint limits, one at a time. Increasing the limit on UPNY-SENY by 1,000 MW showed the most movement in NYCA LOLE and the individual Load Zone LOLE. Zonal LOLE went down for all Zones G-K. This test further indicates the potential of transmission reinforcements and gives valuable insight to the most effective locations for the Compensatory MW development shown in Section 4.3.

Compensatory MW

To provide information to the marketplace regarding the magnitude of the resources that are required to meet the BPTF transmission security needs, Table 4-9 contains a summary of the minimum compensatory MW to satisfy the transmission security violations identified in Section 4.2.1.

The compensatory MW identified in Table 4-9 are for illustrative purposes only and are not meant to limit the specific facilities or types of resources that may be offered as Reliability Needs solutions. Compensatory MW may reflect generation capacity (MVA), demand response, or transmission additions.

Table 4-9: Compensatory MW Additions for Transmission Security Violations

Zone	Owner	Monitored Element	2015 MVA Overload	2015 Min. Comp. MW	2019 MVA Overload	2019 Min. Comp. MW	2024 MVA Overload	2024 Min. Comp. MW
A	N.Grid	Packard-Huntley (#77) 230 (Packard-Sawyer)					5	7
A	N.Grid	Packard-Huntley (#78) 230 (Packard-Sawyer)					5	7
A	N.Grid	Huntley-Gardenville (#79) 230 (Huntley-Sawyer)					10	12
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)			7	9		
							43	51
B	RGE	Pannell 345/115 1TR	90	295				
B	RGE	Pannell 345/115 2TR	90	295				
B	RGE	Pannell-Quaker (#914) 115	49	86				
C	NYSEG	Oakdale 345/115 2TR	17	34				
					12	23	16	30
					18	34	30	56
C	NYSEG	Oakdale 345/115 3TR					10	19
C	N.Grid	Clay-Lockheed Martin (#14) 115	26	35	46	61	48	64
					28	38	32	43
			45	61	84	114	96	130
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	11	15				
C	N.Grid	Clay-Dewitt (#3) 115 (Clay-Bartell Rd)	6	8				
C	N.Grid	Clay 345/115 1TR			73	182	120	299
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)					9	15
					33	54	46	75
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)			10	17	13	22
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	7	10	21	30		
							23	33
E	N.Grid	Porter-Oneida (#7) 115 (Porter-W. Utica)			2	3		
							6	8
F	N.Grid	New Scotland 345/115 1TR	61	141	89	205	267	612
F	N.Grid	Reynolds 345/115	33	109	39	128	125	427
F-G	N.Grid	Leeds-Pleasant Valley (#92) 345					49	160
F-G	N.Grid	Athens-Pleasant Valley (#91) 345					46	152

For resource adequacy deficiencies, the amount and location of the compensatory MW is determined by testing combinations of capacity resources (representing blocks of 50MW of UCAP) located in various load zones until the NYCA LOLE is reduced to 0.1 days per year or less. The process of calculating compensatory MW values informs developers and policy makers by allowing them to test all resource types in meeting needs, by providing additional information on binding interfaces, and allows for the iterative testing of resources in various locations to meet system needs. The purpose of the analyses is not only to show the level of compensatory MW needed to meet the LOLE criterion, but also the importance of the location chosen for the compensatory MW. The results of the MARS simulations for the RNA base case, and scenarios provide information that can be used to guide the compensatory MW analyses as well. If an LOLE violation is, to some extent, caused by a frequently constrained interface, locating compensatory MW upstream of that load zone will result in a higher level of required compensatory MW to meet resource adequacy requirements. The location of these compensatory MW assumes that there are no impacts on internal zonal constraints or the present interface limits into or out of the Zone(s) being tested. These impacts will be determined for the solutions that will be evaluated in the CRP.

Not all alternatives tested were able to achieve an LOLE of less than or equal to 0.1 days per year. The results of the compensatory MW calculation show that by 2024, a total of 1,150 MW are required to mitigate the reliability criteria violations in the base case.

Table 4-10: Compensatory MW Additions for Resource Adequacy Violations

Year	Zones for Additions			
	Only in ABCEF	Only in G-K	Only in J	Only in K
2015	-	-	-	-
2016	-	-	-	-
2017	-	-	-	-
2018	-	-	-	-
2019	400	100	100	100
2020	3,900	300	300	300
2021	5,600	500	500	500
2022	7,400	700	700	800
2023	not feasible	950	950	1,100
2024	not feasible	1,150	1,150	1,500

Review of the results indicates that adequate compensatory MW must be located within Zone G through K because of the existing transmission constraints into those Zones. Potential solutions could include a combination of additional transfer capability into Zones G through K from outside those zones and/or resources located within Zones G through K. Further examination of the results reveals that the constraining hours of UPNY-SENY and Dysinger East are increasing over the Study Period. Binding hours for interface below UPNY-SENY are not that significant in 2024 for the base case, but would increase greatly if significant resources are added exclusively to Zone K.

These results indicate that the total amount of compensatory MW could be located anywhere within SENY; no individual zone has a unique requirement. Although the effectiveness of compensatory MW located in Zones A through F and Zone K diminishes as the transmission constraints to the deficient zones become more binding, these compensatory MW will help to mitigate the statewide LOLE violations. Compensatory MW located in Zones A through F, and assuming equal distribution, is only reasonably effective for 2019, and even then would require four times as much MW to be as effective. The effectiveness diminishes rapidly for future years and becomes non feasible in 2023. For Zone K, the compensatory MW would be as effective up to 500 MW to the year 2021, with a reduction in effectiveness of approximately thirty percent in 2024. The NYISO will evaluate proposed solutions effectiveness in mitigating LOLE violations and any impacts on transfer limits during the development of the 2014 CRP. There are other combinations of compensatory MW that would also meet the statewide reliability criteria, but it is not the intent of this analysis to identify preferred locations or combinations for potential solutions.

The regulated backstop solutions may take the form of alternative solutions of possible resource additions and system changes. Such proposals will provide an estimated implementation schedule so that trigger dates could be determined by the NYISO for purposes of beginning the regulatory approval and development processes for the regulated backstop solutions if market solutions do not materialize in time to meet the reliability needs.

4.4. **Dunkirk Plant Fuel Conversion Sensitivity**

The Dunkirk plant sensitivity evaluates the NYCA system using the base case assumptions, with the added assumption that the proposed fuel conversion of Dunkirk units #2, #3, and #4, a total of 435 MW, from coal to natural gas is completed prior to summer 2016.

The impact of Dunkirk generation returning to service on the NYCA BPTF[3] was assessed in this sensitivity analysis. The availability of Dunkirk after the fuel conversion project relieves the transmission security thermal violations in Buffalo and Binghamton areas.

The transmission security analysis with Dunkirk not in-service continues to identify several thermal violations on the BPTF for N-1, N-1-0, and N-1-1 conditions under 50/50 coincident peak load forecast conditions. With Dunkirk in-service, the thermal violations observed in the RNA base case in the Western New York region and the Binghamton Area (Oakdale 345/230/115 kV substation) are resolved. In the Central region the overloads observed in the Oswego, Utica, and Syracuse areas are reduced, but not resolved with Dunkirk in-service due to a higher west to east flow, but require further system changes to resolve the overloads. The Capital and Southeast regions are insignificantly impacted with Dunkirk in-service. The voltage violations observed in the RNA base case in the Binghamton and Utica areas are not resolved with Dunkirk in-service because Dunkirk is too far removed geographically to have any substantial effect on these violations.

Table 4-11 provides a summary of the contingency pairs with Dunkirk in-service that result in the highest thermal overload on each violated BPTF element in the Central region under N-1, N-1-0, and N-1-1 conditions under 50/50 coincident peak load conditions. In the second contingency column of Table 4-11, “N/A” corresponds to an N-1 violation and “Base Case” corresponds to an N-1-0 violation. Considering non-coincident zonal peak loading, the overloads listed in Table 4-11 can increase, most notably in the out-years.

[3] The local transmission projects are modeled appropriately according to PSC Case 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements – Materials Presented at October 31, 2013 Technical Conference, presented by National Grid.

Table 4-11: 2014 RNA 50/50 Forecast Transmission Security Thermal Violations with Dunkirk In-Service

Zone	Owner	Monitored Element	Normal Rating (MVA)	LTE Rating (MVA)	STE Rating (MVA)	2019 Flow (MVA)	2024 Flow (MVA)	Dunkirk In-Service First Contingency	Dunkirk In-Service Second Contingency
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	155	160	SB Oswego 345	N/A
						128	131	OS-EL-Lafayette (#17) 345	Base Case
						184	190	Clay-Wood (#17) 115	SB Oswego 345
C	N.Grid	Clay 345/115 1TR	478	637	794	698	723	OS-EL-Lafayette (#17) 345	SB Clay 345
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	183	194	Clay-Lockheed Martin (#14) 115	SB Lafayette 345
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	104	104	104	112	113	Clay 345/115 1TR	SB Clay 345
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	135	137	OS-EL-Lafayette (#17) 345	SB Clay 345

For resource adequacy assessment, dynamic limit tables are implemented on two interfaces, Dysinger East and Zone A Group, and the details are included in Appendix D. Starting in 2019, NYCA LOLE exceeds 0.1, and the return of Dunkirk to service following its fuel conversion does not change the Need Year.

4.5. **Scenarios**

The NYISO develops reliability scenarios pursuant to Section 31.2.2.5 of Attachment Y of the OATT. Scenarios are variations on the RNA base case to assess the impact of possible changes in key study assumptions which, if they occurred, could change the timing, location or degree of Reliability Criteria violations on the NYCA system during the study period. The following scenarios were evaluated as part of the RNA:

- High Load (Econometric) Forecast (impacts associated with projected energy reductions produced statewide)
- Transmission security assessment using a 90/10 load forecast
- Zonal Capacity at Risk
- Indian Point Plant Retirement assessment
- Stressed Winter Condition assessment

4.5.1. High Load (Econometric) Forecast

The RNA base case forecast includes impacts associated with projected energy reductions coming from statewide energy efficiency and retail PV programs. The High Load Forecast Scenario excludes these energy efficiency program impacts from the peak forecast, resulting in the econometric forecast levels, and is shown in Table 3-2. This results in a higher peak load in 2024 than the base case forecast by 2,079 MW. Given that the peak load in the econometric forecast is higher than the base case, the probability of violating the LOLE criterion increases with violations also occurring at any earlier point in time.

The results indicate the LOLE would be 0.08 in 2016 and would increase to 0.13 by 2017 under the high load scenario. If the high load forecast were to materialize, the year of need for resource adequacy would be advanced by two years from 2019 in the base case to 2017 in the high load scenario. The horizon year, 2024, LOLE would increase from 0.26 to 0.81 absent system changes to resolve violations in earlier years.

4.5.2. Zonal Capacity at Risk

The base case LOLE does not exceed 0.10 until 2019. Scenario analyses were performed to determine the reduction in zonal capacity (i.e., the amount of capacity in each zone that could be lost) which would cause the NYCA LOLE to exceed 0.10 in each year from 2015 through 2018. The NYISO reduced zonal capacity to determine when violations occur in the same manner as the compensatory MW are added to mitigate resource adequacy violations, but with the opposite impact. The zonal capacity at risk analysis is summarized in Table 4-12.

Table 4-12: Zonal Capacity at Risk (MW)

	2015	2016	2017	2018
Zone A	1,550	1,750	1,450	750
Zone B	exceeds zonal resources	exceeds zonal resources	exceeds zonal resources	450
Zone C	2,200	1,850	1,100	450
Zone D	exceeds zonal resources	exceeds zonal resources	1,100	450
Zone E	exceeds zonal resources	exceeds zonal resources	exceeds zonal resources	500
Zone F	1,800	1,700	1,050	450
Zones A-F	2,500	2,200	1,300	550
Zone G	650	750	400	150
Zone H	650	750	400	150
Zone I	N/A	N/A	N/A	N/A
Zones G-I	650	750	400	150
Zone J	650	750	400	150
Zone K	550	550	350	150

The zones at risk analyses identify a maximum level of capacity that can be removed without causing LOLE violations. However, the impact of removing capacity on the reliability of the transmission system and the transfer capability are highly location dependent. Thus, in reality, lower amounts of capacity removal are likely to result in reliability issues at specific transmission locations. The study did not attempt to assess a comprehensive set of potential scenarios that might arise from specific unit retirements. Therefore, actual proposed capacity removal from any of these zones would need to be further studied in light of the specific capacity locations in the transmission network to determine whether any additional violations of reliability criteria would result. Additional transmission security analysis, such as N-1-1 analysis, would need to be performed for any contemplated plant retirement in any zone.

4.5.3. Indian Point Retirement Assessment

Because its owners submitted license renewal applications on a timely basis, the Indian Point Plant is authorized to continue operations throughout its currently ongoing license renewal processes. This scenario studied the impacts if the Indian Point Plant were instead to be retired by the end of 2015 (the later of the two current license expiration dates). Significant violations of transmission security and resource adequacy criteria would occur in 2016 if the Indian Point Plant were to be retired as of that time. These results were determined using the base case assumptions with the additional change that the Con Edison load was modified to incorporate 125 MW of targeted load reduction projects, consisting of 100 MW of Energy Efficiency and Demand Reduction, and 25 MW of Combined Heat and Power distributed generation.

The Indian Point Plant has two base-load units (2,060 MW total) located in Zone H in Southeastern New York, an area of the State that is subject to transmission constraints that limit transfers in that area as demonstrated by the reliability violations that arise by 2019 in the base case. Southeastern New York, with the Indian Point Plant in service, currently relies on transfers to augment existing capacity. Consequently, load growth or loss of generation capacity in this area would aggravate constraints.

The transmission security analysis has not materially changed since the 2012 RNA regarding the need year under the Indian Point retirement scenario. The results showed that the shutdown of the Indian Point Plant exacerbates the loading across the UPNY-SENY interface, with the Leeds – Pleasant Valley and Athens – Pleasant Valley 345 kV lines above their LTE ratings in 2016.

Using the base case load forecast adjusted for the Con Edison EE program, LOLE is 0.31 in 2016 with Indian Point Plant retired, which is a substantial violation of the 0.1 days per year criterion. Beyond 2016, the LOLE continues to escalate due to annual load growth for the remainder of the Study Period reaching an LOLE of 1.17 days per year in 2024. The NYCA LOLE is summarized in Table 4-13 below.

Table 4-13: Indian Point Plant Retirement LOLE Results

Indian Point Plant Retirement	2016	2017	2018	2019	2020	2021	2022	2023	2024
NYCA LOLE	0.31	0.40	0.40	0.59	0.67	0.76	0.89	1.03	1.17

Compared with 2012 RNA, the resulting LOLE violations are lower, but continue to substantially exceed the LOLE requirement should the Indian Point Plant retire. Note that with the large loss of capacity, the LOLE violations increase exponentially. Other factors, such as Transmission Owner Transmission Solutions (TOTS), decrease the impact of the loss of capacity, but will not solve the violations.

4.5.4. Transmission Security Assessment Using 90/10 Load Forecast

The 90/10 peak load forecast represents an extreme weather condition (e.g. hot summer day). Table 4-14 provides a summary of the 90/10 coincident peak load forecast through the ten-year study period compared to the total resources modeled as available, resulting in the total remaining resources on a year-by-year basis. The resource totals include net purchases and sales, and all available thermal and large hydro units are modeled at 100% of their summer capability. Derates to small hydro, wind, and solar PV are applied consistent with the transmission security base case assumptions.

As shown in Table 4-14, based on the assumptions applied in this analysis, beginning in 2017 there are insufficient resources to meet the minimum 10-minute operating reserve requirement of 1,310 MW[4]. Due to insufficient generation represented in the power flow case

[4] New York State Reliability Council, "NYSRC Reliability Rules for Planning and Operating the New York State Power System", Version 33, dated April 10, 2014

to meet the minimum operating reserve, loss of source contingencies are not studied in the 2019 case. Starting in 2020, there are insufficient resources to meet the modeled 90/10 peak load; therefore, a transmission security assessment was not performed under 90/10 conditions in the 2024 case. In 2015, there are sufficient resources to meet the minimum operating reserve, and thus, all design criteria contingencies are evaluated.

Table 4-14: 90/10 Peak Load Forecast NYCA Remaining Resources (MW)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Resources*	38,313	38,332	38,017	38,017	38,017	38,017	38,017	38,017	38,017	38,017
90/10 Peak Load Forecast	36,397	36,764	37,142	37,506	37,870	38,089	38,338	38,592	38,850	39,073
Remaining Resources	1,916	1,568	875	511	147	-72	-321	-575	-833	-1,056

* Total resources include NYCA generation and net purchases & sales. Assumes 100% availability of thermal and large hydro units; small hydro, wind and solar PV are derated.

The four primary regions of Reliability Needs due to transmission security violations identified in the RNA base case are exacerbated under 90/10 coincident peak load conditions. Table 4-15 provides a summary of the contingency pairs that result in the highest thermal overload on BPTF elements that are not observed under 50/50 coincident peak load conditions. Table 4-16 shows that increased load growth across the state exacerbates the violations identified in the RNA base case. These reliability needs are generally driven by recent and proposed generator retirements/mothballs combined with higher levels of load growth. For both tables, in the second contingency column “N/A” corresponds to a violation occurring under N-1 conditions and “Base Case” corresponds to a violation under an N-1-0 conditions.

While the 90/10 peak load forecast does result in additional overloads, those overloads occur in the same four primary regions of Reliability Needs identified in the 50/50 peak load base case. As shown in Table 4-16, the increased peak load would also result in the earlier occurrence of the Reliability Needs identified in the 50/50 peak load base case. Although the Leeds – Pleasant Valley 345 kV lines are not overloaded in 2015 under the conditions studied, those lines are loaded to 98% of the LTE rating under 90/10 peak load N-1-1 conditions. Any significant reduction of generation or imports in Southeast New York in 2015 would result in an overload on Leeds – Pleasant Valley 345 kV for the evaluated 90/10 peak load conditions.

Table 4-15: 90/10 Transmission Security Violations Not Observed Under 50/50 Load Conditions

Zone	Owner	Monitored Element (kV)	Normal Rating (MVA)	LTE Rating (MVA)	STE Rating (MVA)	2015 Flow (MVA)	2019 Flow (MVA)	First Contingency (kV)	Second Contingency (kV)
A	N.Grid	Niagara-Packard (#61) 230	620	717	841		738	Oswego-Volney (#12) 345	T:62&BP76
A	N.Grid	Niagara-Packard (#62) 230	620	717	841		801	Oswego-Volney (#12) 345	T:61&64
A	N.Grid	Niagara 230/115 AT2	192	239	288		264	Niagara-Packard (#61) 230	SB Packard 230
B	RGE	Pannell 345/115 3TR	255	319	336	258		L/O Ginna	Base Case
B	RGE	Station 82-Mortimer 115	258.1	357.9	410.4	277		Niagara-Robinson Rd (#64) 345	Base Case
						388		L/O Ginna	SB Pannell 345
B	RGE	Station 80 345/115 2TR	330	415	478	444		Station 80 345/115 5TR	SB Station 80 345
B	RGE	Station 80 345/115 5TR	462	567	630	636		Station 80 345/115 2TR	SB Station 80 345
C	N.Grid	Clay 345/115 2TR	478	637	794		695	Clay 345/115 1TR	SB Oswego 345
C	N.Grid	Clay-Dewitt (#3) 115 (Bartell Rd-Pine Grove)	116	120	145	138		Clay-Dewitt (#13) 345	SB Oswego 345
C	N.Grid	Clay-Woodard (#17) 115 (Clay-Euclid)	220	252	280		260	Clay-Lockheed Martin (#14) 115	SB Lafayette 345
C	N.Grid	Clay-Lighthouse Hill (#7) 115 (Lighthouse Hill-Mallory)	108	108	108		123	Clay 345/115 1TR	SB Clay 345
C	NYSEG	Watercure 345/230 1TR	440	540	600	568		Oakdale 345/115 2TR	SB Oakdale 345
E	N.Grid	Porter-Yahnundasis (#3) 115 (W. Utica-Walesville)	116	120	145		123	Clay-Dewitt (#13) 345	SB Oswego 345

Table 4-16: 50/50 Transmission Security Violations Exacerbated Under 90/10 Load Conditions

Zone	Owner	Monitored Element (kV)	Normal Rating (MVA)	LTE Rating (MVA)	STE Rating (MVA)	2015 Flow (MVA)	2019 Flow (MVA)	First Contingency (kV)	Second Contingency (kV)
A	N.Grid	Packard-Huntley (#77) 230 (Packard-Sawyer)	556	644	704		663	Packard-Huntley (#78) 230	SB Robinson Rd. 230
A	N.Grid	Packard-Huntley (#78) 230 (Packard-Sawyer)	556	644	746	645	663	Packard-Huntley (#77) 230	SB Robinson Rd. 230
A	N.Grid	Huntley-Gardenville (#79) 230 (Huntley-Sawyer)	566	654	755	661	672	Huntley-Gardenville (#80) 230	SB Robinson Rd. 230
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755		662	Huntley-Gardenville (#79) 230	N/A
							568	Huntley-Gardenville (#79) 230	Base Case
						692		Robinson Rd.-Stolle Rd. (#65) 230	Huntley-Gardenville (#79) 230
							716	Stolle Rd.-Gardenville (#66) 230	Huntley-Gardenville (#79) 230
B	RGE	Pannell 345/115 1TR	228	282	336	247		L/O Ginna	Base Case
						414		L/O Ginna	SB Pannell 345
B	RGE	Pannell 345/115 2TR	228	282	336	247		L/O Ginna	Base Case
						414		L/O Ginna	SB Pannell 345
							293	Station 80-Pannell (RP-1) 345	SB Pannell 345
B	RGE	Pannell-Quaker (#914) 115	207.1	246.9	284.8	316		L/O Ginna	Pannell 345/115 3TR
C	NYSEG	Oakdale 345/115 2TR	428	556	600		583	SB Oakdale 345	N/A
						478	491	Oakdale 345/115 3TR	Base Case
						637	688	Fraser 345/115 2TR	SB Oakdale 345
C	NYSEG	Oakdale 345/115 3TR	428	556	600	472	484	Oakdale 345/115 2TR	Base Case
						618		Watercure 345/115 1TR	SB Oakdale 345
							587	Oakdale 345/115 2TR	SB Oakdale 345
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	162	184	SB Oswego 345	N/A
						134	161	Elbridge 345/115 1TR	Base Case
						198	234	Clay-Wood (#17) 115	SB Lafayette 345
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	116	120	145	149		Clay-Dewitt (#13) 345	SB Oswego 345
C	N.Grid	Clay-Dewitt (#3) 115 (Clay-Bartell Rd)	116	120	145	151		Clay-Dewitt (#13) 345	SB Oswego 345
C	N.Grid	Clay 345/115 1TR	478	637	794	736		Oswego-Elbridge-Lafayette (#17) 345	SB Clay 345
			478	637	794		778		
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174		200	SB Lafayette 345	N/A
						201	240	Clay-Lockheed Martin (#14) 115	SB Lafayette 345
C	N.Grid	Clay-S. Oswego (#4) 115 (S. Oswego-Whitaker)	104	104	104	120	121	Clay 345/115 1TR	SB Clay 345
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	123	132	SB Oswego 345	N/A
							129	Porter-Oneida (#7) 115	Base Case
						147	155	Clay-Dewitt (#13) 345	SB Oswego 345
E	N.Grid	Porter-Oneida (#7) 115 (Porter-W. Utica)	116	120	145	129	140	Clay-Dewitt (#13) 345	SB Oswego 345
F	N.Grid	New Scotland 345/115 1TR	458	570	731	707		L/O Bethlehem	New Scotland 345/115 2TR
F	N.Grid	Reynolds 345/115	459	562	755	562		L/O Bethlehem	Base Case
F-G	N.Grid	Leeds-Pleasant Valley (#92) 345	1331	1538	1724		1711	Athens-Pleasant Valley (#91) 345	T:41&33
F-G	N.Grid	Athens-Pleasant Valley (#91) 345	1331	1538	1724		1695	Leeds-Pleasant Valley (#92) 345	T:41&33

4.5.5. Stressed Winter Condition Assessment

Five major cold snaps were experienced during the 2013-2014 winter season, including three polar vortex events that chilled large swaths of the Eastern Interconnection and the remainder of the United States. During this time the NYISO set a new winter peak of 25,738 MW while neighboring ISOs and utilities concurrently set their own record winter peaks during the month of January as well. The extreme winter weather conditions resulted in high load conditions, transmission and generation derates, and gas pipeline constraints.

The widespread impact reduced the ability of neighboring areas to provide assistance to New York. Highlights of the peak day recorded on January 7, 2014 follow:

- On January 7, the NYISO set a new record winter peak load of 25,738 MW[5].
- 25,541 MW -- Prior record winter peak load set in 2004
- 24,709 MW -- "50/50" forecast winter peak for 2013-14
- 26,307 MW -- "90/10" forecast winter peak for 2013-14
- Many other ISOs and utilities set record Winter Peaks, including PJM, MISO, TVA, and Southern Company; although NYCA did not lose the ability to provide and receive emergency assistance from neighboring pools. The record shows that NYCA exported power to PJM while importing from HQ, ISO-NE and IESO.
- The NYISO experienced 4,135 MW of generator derates over the peak hour.
- The NYISO activated demand response resources on a voluntary basis in all zones to maintain operating reserve criteria; however, because the 21-hour prior notification was not provided demand response participation was limited.
- The NYISO issued a NERC Energy Emergency Alert 1 indicating that the NYISO was just meeting reserve requirements.
- The NYISO issued public appeals for customers to curtail non-essential use.

Based upon this experience, the scenario was constructed to gauge the amount of capacity that could be lost from the NYCA while restricting the ability to receive assistance from our neighbors. Capacity was removed from all NYCA zones proportional to zonal capacity at each external assistance level until an annual LOLE violation was observed for the year. Additionally, the hourly loads in the MARS model for the month of January 2015 were modified to reflect actual January 2014 loads for all three input load shapes. The experienced January 2014 peak was normalized to 50/50 conditions and the load forecast uncertainty (LFU) bins for winter conditions were updated for the MARS model. These values are shown in Table 4-17.

[5] This value is the actual load prior to adjustment for demand response that was activated at the time of the system winter peak.

Table 4-17: Derivation of 2014 NYCA Winter LFU

Zones	Bin 1	Bin 2	Bin 3	Bin 4	Bin 5	Bin 6	Bin 7
A	1.136	1.090	1.045	1.000	0.955	0.910	0.864
B	1.135	1.090	1.045	1.000	0.955	0.910	0.865
C	1.136	1.091	1.045	1.000	0.955	0.909	0.864
D	1.170	1.113	1.057	1.000	0.943	0.887	0.830
E	1.136	1.091	1.045	1.000	0.955	0.909	0.864
F	1.136	1.090	1.045	1.000	0.955	0.910	0.864
G	1.136	1.090	1.045	1.000	0.955	0.910	0.864
H	1.158	1.105	1.053	1.000	0.947	0.895	0.842
I	1.158	1.105	1.053	1.000	0.947	0.895	0.842
J	1.158	1.105	1.053	1.000	0.947	0.895	0.842
K	1.180	1.120	1.060	1.000	0.940	0.880	0.820
NYCA	1.151	1.101	1.051	1.000	0.949	0.899	0.849
Probability	0.0062	0.0606	0.2417	0.383	0.2417	0.0606	0.0062

In order to model a statewide LOLE violation in 2015, the annual LOLE of 0.06, as observed in Table 4-7, was subtracted from the reliability criterion level of 0.1 days/yr to reach a target LOLE of 0.04 for this scenario. January 2015 was then simulated with multiple levels of NYCA capacity loss and external import capability reduction until the target January LOLE was observed.

Many factors can impact the emergency assistance from neighboring control areas; therefore a simple approach was adopted and applied to this scenario. By creating a NYCA import interface that was defined as encircling all of NYCA, it became possible to limit the external import capability by defining a MW flow limit. In the conservative case that NYCA is unable to receive emergency assistance from any of the neighboring areas, it would take a capacity loss of 7,250 MW of resources in an extreme weather condition to result in an annual LOLE violation in year 2015.

Table 4-18: Simultaneous NYCA Import Limits and MW Lost in Stressed Winter Scenario

Limit (MW)	MW Lost
4,000	11,300
2,000	9,300
0	7,250

5. Impacts of Environmental Regulations

5.1. Regulations Reviewed for Impacts on NYCA Generators

The 2012 RNA identified new environmental regulatory programs that could impact the operation of the Bulk Power Transmission Facilities. These state and federal regulatory initiatives cumulatively will require considerable investment by the owners of New York's existing thermal power plants in order to comply. The following programs are reviewed in the 2014 RNA:

a) *NOx RACT*: Reasonably Available Control Technology (Effective July 2014)

b) *BART*: Best Available Retrofit Technology for regional haze (Effective January 2014)

c) *MATS*: Mercury and Air Toxics Standard for hazardous air pollutants (Effective April 2015)

d) *MRP*: Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units – Phase II reduces Mercury emissions from coal fired power plants in New York beginning January 2015

e) *CSAPR*: Cross State Air Pollution Rule for the reduction of SO2 and NOx emissions in 28 Eastern States. The U.S. Supreme Court has upheld the CSAPR as promulgated by USEPA. The Supreme Court remanded the rule to the District Circuit Court of Appeals for further proceedings, and eventual implementation by the USEPA.

f) *CAIR*: Clean Air Interstate Rule will continue in place until CSAPR is implemented

g) *RGGI*: Regional Greenhouse Gas Initiative Phase II cap reductions started January 2014

h) *CO2 Emission Standards*: NSPS scheduled to become effective June 2014, Existing Source Performance Standards may be effective in 2016

i) *RICE*: NSPS and NESHAP – New Source Performance Standards and Maximum Achievable Control Technology for Reciprocating Internal Combustion Engines (Effective July 2016).

j) *BTA*: Best Technology Available for cooling water intake structures (Effective upon Permit Renewal)

The NYISO has determined that as much as 33,200 MW in the existing fleet (88% of 2014 Summer Capacity) will have some level of exposure to the new regulations.

5.1.1. Reasonably Available Control Technology for NOx (NOx RACT)

The NYSDEC has promulgated revised regulations for the control of Nitrogen Oxides (NOx) emissions from fossil-fueled electric generating units. These regulations are known as NOx RACT (Reasonably Available Control Technology). In New York, 221 units with 27,100 MW of capacity are affected. The revised emission rate limits become effective on July 1, 2014.

There are three major NOx RACT System Averaging "bubbles" in Zone J: TC Ravenswood (TCR Bubble), NRG Arthur Kill- Astoria Gas Turbines (NRG Bubble), and USPowerGen Astoria-Narrows and Gowanus Gas Turbines (USPowerGen Bubble). Historically the boilers have demonstrated the ability to operate at emission rates that are below the presumptive emission rates in the NOx RACT regulation. On the other hand, the older gas turbines in Zone J frequently operate at emission rates in excess of the presumptive limits. With planning and careful operation, the units within the bubbles can be operated in a manner such that the higher emission rates from the gas turbines can be offset by the lower emission rates from the boilers. Table 5-1 below has the presumptive NOx RACT emission limits that were in effect until June 30, 2014. Table 5-2 has the new presumptive emission limits effective starting from July 1, 2014. The emission limits for the gas turbines remain unchanged. It is apparent that the ability of the boilers to offset emissions from the gas turbines will be significantly reduced with the new limits.

Table 5-1: NOx RACT Limits Effective until June 30, 2014

Fuel Type	Boiler Type (Pounds/mmBTU or #/mmBTU)			
	Tangential	Wall	Cyclone	Stoker
Gas Only	0.20	0.20	-	-
Gas/Oil	0.25	0.25	0.43	-
Coal Wet	1.00	1.00	0.60	-
Coal Dry	0.42	0.45	-	0.30

Table 5-2: New NOx RACT Limits Effective Starting from July 1, 2014

Fuel Type	Boiler Type (Pounds/mmBTU or #/mmBTU)			
	Tangential	Wall	Cyclone	Fluidized Bed
Gas Only	0.08	0.08	-	-
Gas/Oil	0.15	0.15	0.20	-
Coal Wet	0.12	0.12	0.20	-
Coal Dry	0.12	0.12	-	0.08

Using publicly available information from USEPA and USEIA, estimated NOx emission rates can be determined across the operating spectrum for various combinations of fuels for specific units greater than 15 MW. Using this information, the NYISO has analyzed potential NOx emissions under the lower NOx RACT standards to determine if the system emission averaging plans can be achieved. The analysis has focused on the peak day July 19, 2013 in Zone J. It appears that compliance with the TC Ravenswood emission plan should be feasible without imposing the operating limits on the affected units.

The analysis of the NRG bubble shows that operation of the complete fleet of gas turbines could be sustained in a manner consistent with the actual operating profile on the peak day. Similarly, supplemental data provided by USPowerGen demonstrates that the fleet of gas turbines could operate in a manner similar to what it did on the peak day in 2013. Given that this analysis is based upon historic performance which occurred when the emission limits were higher, it is possible that the boilers could achieve lower emission rates and therefore the gas turbines could operate for more extended periods.

Conversely, invoking the Loss of Gas Minimum Oil Burn (LOG-MOB) reliability rule requires the boilers under certain conditions to burn residual fuel oil (RFO) which increases NOx emissions and reduces the ability of the boilers to produce necessary offsets. Incremental operation of the boilers on gas during off peak hours could mitigate the impact of increased NOx emissions from LOG-MOB on the reduced hours of operation of the gas turbine.

5.1.2. Best Available Retrofit Technology (BART)

The class of steam electric units constructed between 1963 and 1977 are subject to continuing emission reductions required by the Clean Air Act. In New York, there are 15 units in service with 7,531 MW of summer capacity that are affected. Table 5-3 identifies the new emission limitations in place for these units[6].

[6] The table is not intended to include all emission limitations.

Table 5-3: New BART Emission Limits

Applicable Plants	Unit(s)	DMNC [1] (MW)	SO_2	NOx	Particulate Matter
Arthur Kill	ST 3	500	-	0.15 #/mmBTU; 24 Hours.	-
Bowline	1, 2	758	0.37% S RFO	0.15 #/mmBTU for gas, and 0.25 #/mmBTU for oil; 24 Hours	-
Barrett	ST 02	196	0.37% S RFO	0.1/0.2 #/mmBTU Gas/ Oil; 24 Hours	0.1 #/mmBTU
Northport	1,2,3,4	1,583	0.7% S RFO	0.1/0.2 #/mmBTU Gas/ Oil; 24 Hours	-
Oswego	5,6	1,574	0.75% S RFO	383/665 tons per year	-
Ravenswood	ST 01, ST 02 and ST 03	1,693	0.30% S RFO	0.15 #/mmBTU 30 Day	-
Roseton	1, 2	1,227	0.55#/mmBTU	-	-
Danskammer	4	237[2]	0.09#/mmBTU; 24 Hours	0.12#/mmBTU; 24 Hours	0.06 #/mmBTU; 1 Hour
2014 In-Service		7,531			

Notes:
1. Summer capability from 2014 Gold Book
2. Not included in 2014 In-Service total

The new BART limits identified in Table 5-3 are not expected to affect availability of these units during times of peak demand.

5.1.3. Mercury and Air Toxics Standards (MATS)

The USEPA Mercury and Air Toxics Standards (MATS) will limit emissions of mercury and air toxics through the use of Maximum Achievable Control Technology (MACT) for Hazardous Air Pollutants (HAP) from coal and oil fueled steam generators with a nameplate capacity of 25 MW or more. MATS will affect 23 units in the NYCA that represent 10,300 MW of nameplate capacity. Compliance requirements begin in March 2015 with an extension through March 2017 for Reliability Critical Units (RCU).

The majority of the New York coal fleet has installed emission control equipment that may place compliance within reach. One coal fired unit in New York is considering seeking an extension of the compliance deadline to March 2017.

The heavy oil-fired units will need to either make significant investments in emission control technology or switch to a cleaner mix of fuels in order to comply with the proposed standards. Given the current outlook for the continued attractiveness of natural gas compared to heavy oil, it is anticipated that compliance can be achieved by dual fuel units through the use of natural gas to maintain fuel ratios that are specified in the regulation[7].

5.1.4. Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units (MRP)

New York State also has a mercury emission limit program for coal fired units. Phase II of the program begins January 1, 2015. The allowable emission limit is half of the MATS standard. The impact of the MRP requirements is shown below Section 5.2.

5.1.5. Cross State Air Pollution Rule (CSAPR)

The CSAPR establishes a new allowance system for units with at least 25 MW nameplate capacity or more. Affected generators will need one allowance for each ton emitted in a year. In New York, CSAPR will affect 154 units that represent 25,900 MW of nameplate capacity. The USEPA estimated New York's annual allowance costs for 2012 at $65 million. There are multiple scenarios which show that New York's generation fleet can operate in compliance with the program in the first phase. Compliance actions for the second phase may include emission control retrofits, fuel switching, and new clean efficient generation. The US Supreme Court upheld the CSAPR regulation and remanded the case to the District of Columbia Circuit Court of Appeals to resolve the remaining litigation and work with the USEPA to develop a revised implementation schedule. Further, since the rule was finalized in 2012, two National Ambient Air Quality Standards, for SO2 and Ozone, have been promulgated. The USEPA may recognize these new standards, unit retirements, and/ or changes in load and fuel forecasts in updated modeling that may be necessary for implementation of the CSAPR. EPA has filed with the D.C. Circuit Court of Appeals requesting authority to implement the rule in January 2015.

While the CSAPR is updated and implementation plans are finalized, the Clean Air Interstate Rule (CAIR) remains in effect. CAIR also employs an allowance based system to reduce emissions of SO2 and NOx over time. The rule is designed to begin Phase II on January 1, 2015 with an approximate 50% reduction in emission allowances entering the marketplace. The CAIR marketplace is currently oversupplied with SO2 and NOx emissions allowances, which has resulted in prices that are relatively low. It is expected that the continued operation of CAIR will not impact either the amount of capacity available or the relative dispatch order.

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[7] The MATS regulation provides for an exemption for units that use oil for less than ten percent of heat input annually over a three year period, and less than 15 percent in any given year. The regulation provides for an exemption from emission limits for units that limit oil use to less than the amount equivalent to an eight percent capacity factor over a two year period.

5.1.6. Regional Greenhouse Gas Initiative (RGGI) and USEPA Proposed Carbon Rules

The Regional Greenhouse Gas Initiative established a cap over CO2 emissions from most fossil fueled units of 25 MW or more in 2009. Phase II of the RGGI program became effective January 1, 2014 and reduces the cap by 45% to 91,000,000 tons for 2014. Phase II then applies annual emission cap reductions of 2.5% until 2020. One RGGI Allowance is required for each ton of CO2 emitted during a three year compliance period. A key provision to keep the allowance and electricity markets functioning is the provision of a Cost Containment Reserve (CCR). If demand exceeds supply at predetermined trigger prices an additional 10,000,000 (5,000,000 in 2014) allowances will be added to the market. Trigger prices are set to rise to $10/ton in 2017 and escalate at 2.5% annually thereafter. RGGI Inc. modeling analyses show that the trigger prices will be reached on several occasions throughout the period. Coal units may be further handicapped by the cost of carbon emission allowances, which could add up to $5/MWh in cost compared to older combined cycle units and up to $10/MWh for non-emitting machines.

The USEPA is in the process of promulgating New Source Performance Standards designed to limit CO2 emissions from new fossil fueled steam generators and combined cycle units. While the proposed rule would present significant technological challenges for coal fired units; for gas fired units, the rules are generally less stringent than NYSDEC's existing Part 251 emission regulations. USEPA's rule does not apply to simple cycle turbines that limit their sales to the grid to less than one-third of their potential electrical output.

On June 2, 2014, the USEPA proposed a rule to limit CO2 emissions from existing power plants by 30% from 2005 levels[8]. The rule is designed to lower emission rates from 2012 as measured in terms of # CO2/MWh, however, it does allow states to develop mass based systems such as RGGI. The proposal calls for an initial reduction by 2020 while achievement of the final reductions will be required by 2030. State implementation plans can make use of: (i) coal fired plant efficiency improvements; (ii) shifts in dispatch patterns to increase production from natural gas fired combined cycle plants; (iii) increased construction and operation of low and non-emitting generators; and (iv) aggressive deployment of energy efficiency measures. The proposal calls for the continued operation of existing and completion of new nuclear plants.

[8] The proposed rule is extensive in length, broad in scope, and presents a complex approach to establishing base lines and future emission reduction requirements. The comment period closes in mid-October. The rule will be finalized in June of 2015. State Implementation Plans will be developed with public participation over the following year, or three year period if regional plans are proposed. The NYISO analysis will be a continuing effort over the next several years. At important points in the process, reports will be provided to stakeholders identifying the issues of importance to the NYISO.

5.1.7. RICE: NSPS and NESHAP

In January 2013, the USEPA finalized two new rules that apply to engine powered generators typically used as emergency generators. Some of the affected generators also participate in the NYISO's Special Case Resource (SCR) or Emergency Day-ahead Response (EDRP) Programs. EPA finalized National Emission Standards for Hazardous Air Pollutants (NESHAP), and New Source Performance Standards (NSPS), for Reciprocating Internal Combustion Engines (RICE). The new rules are designed to allow older emergency generators that do not meet the EPA's rules to comply by limiting operations in non-emergency events to less than 15 hours per year. These resources can participate in utility and NYISO emergency demand response programs; however the engine operation is limited to a maximum of 100 hours per year for testing and utility or the NYISO emergency demand response operations for which a Level 2 Energy Emergency Alert is called by the grid operator.

The New York DEC is also developing rules to control emissions of NOx and particulate matter (PM10 and 2.5) from engine driven generators that participate in the EDRP. The proposed rules will apply to all such generators above 150 kW in New York City and above 300 kW in the remainder of the State not already covered by a Title V Permit containing stricter NOx and PM limits. Depending on their specific types, it appears that engines purchased since 2005 and 2006 should be able to operate within the proposed limits. Older engines can be retrofitted with emission control packages, replaced with newer engines, or cease participation in the demand response programs. The proposed rule is generally comparable to rules already in place in a number of other states within the Ozone Transport Region. NYSDEC's estimated compliance schedule is still developing, with a currently contemplated compliance schedule of mid -2016.

5.1.8. Best Technology Available (BTA)

The USEPA has proposed a new Clear Water Act Section 316 b rule providing standards for the design and operation of power plant cooling systems. This rule will be implemented by NYSDEC, which has finalized a policy for the implementation of the Best Technology Available (BTA) for plant cooling water intake structures. This policy is activated upon renewal of a plant's water withdrawal and discharge permit. Based upon a review of current information available from NYSDEC, the NYISO has estimated that between 4,200-7,200 MW of nameplate capacity could be required to undertake major system retrofits, including closed cycle cooling systems. One high profile application of this policy is the Indian Point nuclear power plant. Table 5-4 shows the current status of plants under consideration for BTA determinations.

Table 5-4: NYSDEC BTA Determinations (as of March 2014)

Plant	Status
Arthur Kill	BTA Decision made, monitoring
Astoria	BTA Decision made, installing equipment
Barrett	Repowering Study underway, otherwise closed cycle
Bowline	BTA Decision made, capacity factor limited to 15% over 5 years
Brooklyn Navy Yard	BTA Decision made, installing upgrades
Cayuga	BTA Decision made, install screens, UPP accepted, Sierra Club challenged
Dunkirk	BTA Decision made, monitoring
East River	BTA installed, monitoring
Fitzpatrick	NYSDEC ready to issue BTA determination for offshore intake and screens
Fort Drum	BTA installed, monitoring
Ginna	BTA Decision 2015 or later
Huntley	BTA Decision capacity factor limited and variable speed pumps, NRG and Sierra Club have requested hearings
Indian Point	Hearings, BTA Decision 2016 at the earliest
Nine Mile Pt 1	Possible BTA determination this year
Northport	Possible BTA determination next year
Oswego	Lower priority for NYSDEC, possibly capacity factor limited
Port Jefferson	BTA installed, monitoring
Ravenswood	BTA installed, monitoring
Roseton	In hearings
Somerset	Possible BTA determination this year

The owners of Bowline have accepted a limit on the duration of operation of the plant as their compliance method. NYSDEC's BTA Policy allows units to operate with 15% capacity factor averaged over a five year period provided that impingement goals are met and the plant is operated in a manner that minimizes entrainment. Close inspection of the 2014 RNA MARS simulations shows that Bowline plant was committed at less than the 15% capacity factor limitation; thus imposing the BTA capacity factor limit does not degrade the NYCA LOLE.

More recently, a draft State Pollution Discharge Elimination System permit was issued for public comment for Huntley Station. The draft contained the 15% capacity factor limitation over the next five year period following finalization of the permit. If the proposed operating limitation were to become effective, the output of the plant would need to be significantly reduced over the five year period following finalization of the Huntley SPDES permit, as compared to recent production. The loss of output from Huntley could reduce transfer limits in the area, thereby altering production at Niagara and limiting imports from Ontario. To reflect the impact, the MARS topology for 2014 RNA implemented dynamic limit tables for Dysinger East and Zone A Group interfaces; details are described in Appendix D.

5.2. Summary of Environmental Regulation Impacts

Table 5-4 summarizes the impact of the new environmental regulations. Approximately 33,800 MW of nameplate capacity may be affected to some extent by these regulations. Compliance plans are in place for NOx RACT, BART, and RGGI. Reviewing publicly available information from USEPA and USEIA, most generators affected by MATS and MRP have demonstrated operations with emission levels consistent with the new regulations. BTA determinations are the result of extensive studies and negotiations that in most cases have not resulted in decisions requiring conversion to closed cycle cooling systems. These determinations are made on a plant specific schedule. The Indian Point Nuclear Plant BTA determination is the subject of an extensive hearing and Administrative Law Judge determination process that will continue through 2015.

Table 5-5: Impact of New Environmental Regulations

Program	Status	Compliance Deadline	Approximate Nameplate Capacity
NOx RACT	In effect	July 2014	27,100 MW (221 units)
BART	In effect	January 2014	8,400 MW (15 units)
MATS	In effect	April 2015/2016/2017	10,300 MW (23 units)
MRP	In effect	January 2015	1,500 MW (6 units)
CSAPR	Supreme Court validated USEPA rule	TBD	26,300 MW (160 units)
RGGI	In effect	In effect	25,800 MW (154 units)
BTA	In effect	Upon permit Renewal	16,400 MW (34 units)

Using publicly available information from USEPA and USEIA, the NYISO further identified the units that may experience significant operational impacts from the environmental regulations. The summary is provided below and in Table 5-6:

- *NOx RACT program*: It appears that compliance with each of the three NOx bubble limitation is achievable.
- *BART limits*: The Oswego Units #5 and #6 are estimated to be able to start and operate at maximum output for many more days than they have been committed historically. Accordingly, imposing these estimated BART operating limits does not change NYCA LOLE in 2014 RNA.
- *MATS/MRP Program*: Given the current outlook for the continued attractiveness of natural gas compared to heavy oil, it is anticipated that compliance can be achieved by dual fuel units through the use of natural gas to maintain fuel ratios that are specified in the regulation.
- *RGGI*: The impact of RGGI may increase the operating cost of all coal units. Should all coal units retire, loss of nearly 1,500 MW in upstate would cause LOLE to exceed 0.1/day in year 2017 or before, and cause reliability violations.

Table 5-6: Summary of Potentially Significant Operational Impacts due to New Environmental Regulations

Program	Status	Significant Operational Impacts	Future Operations Potentially Impacted	Capacity (MW)
NOx RACT	July 2014	Three NYC NOx bubbles	Arthur Kill, Astoria Gas Turbines, Astoria, Narrows, Gowanus, Ravenswood	5,300
BART	In effect	Emission caps	Oswego 5 & 6: limited number of days for operations at peak	1,600
MATS/MRP	April 2015/6/7	Oil use limits	Astoria, Ravenswood, Northport, Barrett, Port Jefferson, Bowline, Roseton, Oswego	8,800
CSAPR	Uncertain	Cost increases	Uncertain	
RGGI	In effect	Cost increases up to $10/MWH	All Coal units	1,450
BTA	Permit Renewal	Potential retirements or capacity factor limits	Indian Point, Bowline, and Huntley	3,200

6. Fuel Adequacy

6.1. Gas Infrastructure Adequacy Assessment

As the plentiful low cost gas produced in the Marcellus Shale makes its way into New York, the amount of electrical demand supplied and energy produced by this gas have steadily increased. The benefits of this shift in the relative costs of fossil fuels include reduced emissions, improved generation efficiency, and lower electricity prices. These benefits, however, are accompanied by a reduction in overall fuel diversity in NYCA. This reduction in fuel diversity has led to the Eastern Interconnection Planning Collaborative (EIPC) gas and electric infrastructure study and FERC proceedings addressing gas and electric system communications, and market coordination, all of which are intended to improve the knowledge base for electric and gas system planners, operators, and policy makers.

The NYISO has recently completed a study that examined the ability of the regional natural gas infrastructure to meet the reliability needs of New York's electric system. Specifically the study provided a detailed review of New York gas markets and infrastructure, assessed historic pipeline congestion patterns, provided an infrastructure and supply adequacy forecast and examined postulated contingency events. Importantly, the study concluded there will be no unserved gas demand for generation on the interstate gas pipeline systems throughout the next five years, even with the retirement of Indian Point and related replacement of that generation with 2,000 MW of new capacity in the Lower Hudson Valley.

The study did not examine the impact of intra-state pipeline deliverability constraints on the LDC systems. The study did document increasing congestion on key pipelines in New York resulting from increased gas demand in New England and to a lesser degree by in- state demand increases for generation. Gas fired generators located on constrained pipeline segments may continue to experience gas supply curtailments over the study horizon. Gas pipeline expansions under construction and planned will materially increase delivery capability and result in reduced delivery basis and future interruptions. The market for gas supply forward contracts has already made significant adjustment to recognize the future completion of these projects. The price difference between Henry Hub and the NYC represented by the Transco NY 6 delivery point has disappeared except for a small number of incidences in the winter months. Moreover, New York is fortunate to have dual fuel capability installed at the majority of its gas fired generators.

The NYISO conducted surveys in October 2012 and October 2013 to verify dual fuel capability. Based on the October 2013 survey results, it was determined that of 18,011 MW (Summer DMNC) dual fuel generators reported in the 2013 Gold Book, 16,983 MW have permits that allow them to operate on oil. In addition, there were 2,505 MW (Summer DMNC) oil-only generators reported in the 2013 Gold Book; based on the October 2013 Survey results, this has increased to 2,579 MW (Summer DMNC). Thus, the summer capability of oil and dual fuel units with oil permits totals 19,562 MW. These oil and dual fuel facilities represent a strong fleet of resources that can respond to delivery disruptions on the gas pipeline system during both summer and winter seasons.

6.2. Loss of Gas Supply Assessment

Loss of Gas Supply Assessment was conducted as part of the NYISO 2013 Area Transmission Review (ATR). The findings of the assessment are summarized below.

Natural gas-fired generation in NYCA is supplied by various networks of major gas pipelines, as described in Appendix O of the 2013 ATR. NYCA generation capacity has a balance of fuel mix which provides operational flexibility and reliability. Several generation plants have dual fuel capability. Based on the NYISO 2013 Gold Book, 8% of the generating capacity is fueled by natural gas only, 47% by oil and natural gas, and the remainder is fueled by oil, coal, nuclear, hydro, wind, and other.

The loss of gas supply assessment was performed using the winter 2018 50/50 forecast of the coincident peak load. The power flow base case was developed by assuming all gas only units and dual fuel units that do not have a current license to operate with the alternative fuel are not available due to a gas supply shortage. The total reduction in generating capacity was 4,251 MW; however, only 2,777 MW had to be redispatched due to the modeling assumptions in the base case. N-1 and N-1-1 thermal and voltage analysis was performed using the TARA program monitoring bulk system voltages and all 115 kV and above elements for post-contingency LTE thermal ratings.

No thermal or voltage violations are observed in addition to those already identified for the summer peak conditions for this extreme system condition. The only stability issue noted for this gas shortage scenario was an undamped response to a single-line to ground stuck breaker fault at Marcy on the Marcy – Volney 345kV line. Possible mitigation would be to balance the VAr flow from each plant at the Oswego complex or redispatching the Oswego complex.

The capacity of 2014-2015 winter is summarized in Table 6-1 below. In the event that NYCA loses gas-only units, the remaining capacity is sufficient to supply the load. However, in the extreme case that NYCA loses gas-only units, and simultaneously the oil inventory of all dual-fuel units has been depleted, a total capacity of 16,879 MW would be unavailable. As the consequence of such an extreme event, the remaining generation would not be sufficient to supply NYCA load.

Table 6-1: Loss of Gas Assessment for 2014-2015 Winter

2015 Winter Capacity (MW)	
Peak Load	24,737
NYCA winter capacity	40,220
If gas-only units lose gas supply	
Gas-only capacity	-3,568
Total remaining capacity	36,652
If gas-only and dual-fuel units lose gas supply and deplete oil	
Gas only capacity	-3,568
Dual-fuel capacity	-16,879
Total remaining capacity	19,773

6.3. Summary of Other Ongoing NYISO efforts

The NYISO has been working with stakeholders and other industry groups to identify and address fuel adequacy concerns. Most notably, the Electric Gas Coordination Working Group (EGCWG) and EIPC are actively studying related issues. The efforts are summarized in this section.

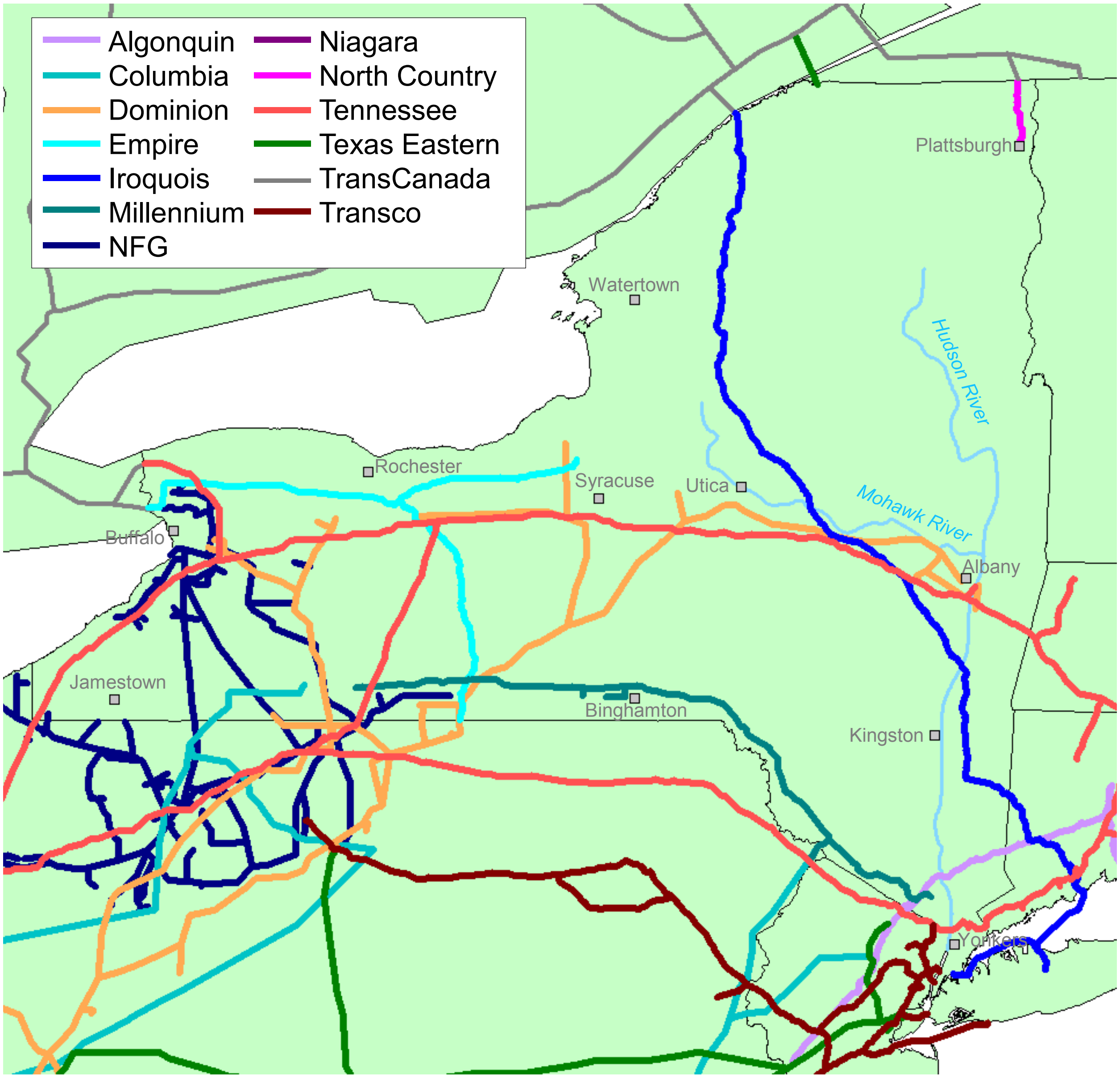
At EGCWG, the efforts are focusing on gas-electric coordination issues within NYCA. The NYISO retained Levitan & Associates (LAI) to prepare the following reports:

- "Fuel Assurance Operating and Capital Costs for Generation in NYCA" (Task 1)
- The "NYCA Pipeline Congestion and Infrastructure Adequacy Assessment" (Task 2)

The final study reports have been completed and are posted on the NYISO website[9]. The consolidated network of interstate pipelines serving New York is shown in Figure 6-1.

[9] Task 1 final report: http://www.nyiso.com/public/committees/documents.jsp?com=bic_egcwg&directory=2013-06-17
Task 2 final report:
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_egcwg/meeting_materials/2013-10-23/Levitan%20Pipeline%20Congestion%20and%20Adequacy%20Report%20Sep13%20-%20Final%20CEII%20Redacted.pdf

Figure 6-1: Natural Gas Pipeline Network in NYCA



At EIPC, six Participating Planning Authorities (PPAs) are actively involved in the Gas-Electric System Interface Study, which includes ISO-NE, NYISO, PJM, IESO, TVA, and MISO (includes the Entergy system). The efforts are focusing on gas-electric coordination issues in the region across the six PAs. The study has four targets:

1. Develop a baseline assessment that includes description of the natural gas-electric system interface(s) and how they impact each other.
2. Evaluate the capability of the natural gas system(s) to supply the individual and aggregate fuel requirement from the electric power sector over a five and ten year study horizon.
3. Identify contingencies on the natural gas system that could adversely affect electric system reliability and vice versa.
4. Review operational and planning issues and any changes in planning analysis and operations that may be impacted by the availability or non-availability of dual fuel capability at generating units.

Target 1 has been completed, and the report is posted on EIPC website[10]. Target 2 is currently underway, while Targets 3 and 4 are in the planning stage.

[10] http://www.eipconline.com/Gas-Electric_Documents.html

7. Observations and Recommendations

The 2014 Reliability Needs Assessment (RNA) assesses resource adequacy and both transmission security and adequacy of the New York Control Area (NYCA) bulk power transmission system from year 2015 through 2024, the study period of this RNA. The 2014 RNA identifies transmission security needs in portions of the bulk power transmission system, and a NYCA LOLE violation due to inadequate resource capacity located in Southeast New York (SENY).

The NYISO finds transmission security violations beginning in 2015, some of which are similar to those found in the 2012 RNA. The NYISO also identifies resource adequacy violations, which begin in 2019 and increase through 2024, if they are not resolved.

For transmission security, there are four primary regions with reliability needs: Rochester, Western & Central New York, Capital Region, and Lower Hudson Valley & New York City. These reliability needs are generally driven by recent and proposed generator retirements or mothballing combined with load growth. The New York transmission owners have developed plans through their respective local transmission planning processes to construct transmission projects to meet not only the needs identified in the previous RNA, but also any additional needs occurring since then and prior to this RNA. These transmission projects, subject to inclusion rules, have been modeled in the 2014 RNA base case. Reliability needs identified in this report exist despite the inclusion of the transmission projects in the base case. The transmission security needs in the Buffalo and Binghamton areas are influenced by whether the fuel conversion project can be completed for the Dunkirk Plant for it to return to service by 2016. As a result, this project was addressed as a sensitivity and the impact of the results are noted with the base case reliability needs.

While resource adequacy violations continue to be identified in SENY, the 2014 RNA is projecting the need year to be 2019, one year before the need year identified in the 2012 RNA. The most significant difference between the 2012 RNA and the 2014 RNA is the decrease of the NYCA capacity margin (the total capacity less the peak load forecast).

The NYISO expects existing and recent market rule changes to entice market participants to take actions that will help meet the resource adequacy needs in SENY, as identified by the 2012 RNA and the 2014 RNA. The resources needed downstream of the upstate New York to SENY interface is approximately 1,200 MW in 2024 (100 MW in 2019), which could be transmission or capacity resources. The new Zones G-J Locality will provide market signals for resources to provide service in this area. Capacity owners and developers are taking steps to return mothballed units to service, restore units to their full capability, or build new in the Zones G-J Locality. If some or all of these units return to service or are developed, the reliability need year would be postponed beyond 2019. In addition, New York State government is promoting transmission development to relieve the transmission constraints between upstate New York and SENY, which could also defer the need for additional resources. The NYISO anticipates that such potential solutions will be submitted for evaluation during the solutions phase of the Reliability Planning Process (RPP) and included in the upcoming 2014 Comprehensive Reliability Plan (CRP) if appropriate.

As a backstop to market-based solutions, the NYISO employs a process to define responsibility should the market fail to provide an adequate solution to an identified reliability need. Since there are transmission security violations in Zones A, B, C, E, and F within the study period, the transmission owners (TOs) in those zones (i.e., National Grid, RGE, and NYSEG) are responsible and will be tasked to develop detailed regulated backstop solutions for evaluation in the 2014 CRP.

Given the limited time between the identification of certain transmission security needs in this RNA report and their occurrence in 2015, the use of demand response and operating procedures, including those for emergency conditions, may be necessary to maintain reliability during peak load periods until permanent solutions can be put in place. Accordingly, the NYISO expects the TOs to present updates to their Local Transmission Owner Plans for these zones, including their proposed operating procedures pending completion of their permanent solutions, for review and acceptance by the NYISO and in the 2014 CRP.

The NYISO identified reliability needs for resource adequacy in SENY starting in the year 2019; therefore, the TOs in SENY (i.e., Orange & Rockland, Central Hudson, New York State Electric and Gas, Con Edison, and LIPA) are responsible to develop the regulated backstop solution(s). The study also identified a transmission security violation in 2022 on the Leeds-Pleasant Valley 345 kV circuit, and this circuit is the main constraint of the Upstate New York to Southeast New York (UPNY-SENY) interface identified in the resource adequacy analysis. Therefore, the violation could be resolved by solution(s) that respond to the resource adequacy deficiencies identified for 2019 – 2024.

If the resource adequacy solution is non-transmission, these reliability needs can only be most efficiently satisfied through the addition of compensatory megawatts in SENY because such resources need to be located below the UPNY-SENY interface constraint to be effective. Additions in Zones A through F could partially resolve these reliability needs. Potential solutions could include a combination of additional transfer capability by adding transmission facilities into SENY from outside those zones and/or resource additions at least some of which would be best located in SENY.

The RNA is the first step of the NYISO reliability planning process. As a product of this step, the NYISO documents the reliability needs in the RNA report, which is presented to the NYISO Board of Directors for approval. The NYISO Board approval initiates the second step, which involves the NYISO requesting proposed solutions to mitigate the identified needs to maintain acceptable levels of system reliability throughout the study period.

8. Historic Congestion

Appendix A of Attachment Y of the NYISO OATT states: "As part of its CSPP, the ISO will prepare summaries and detailed analysis of historic and projected congestion across the NYS Transmission System. This will include analysis to identify the significant causes of historic congestion in an effort to help Market Participants and other interested parties distinguish persistent and addressable congestion from congestion that results from onetime events or transient adjustments in operating procedures that may or may not recur. This information will assist Market Participants and other stakeholders to make appropriately informed decisions." The detailed analysis of historic congestion can be found on the NYISO Web site.[11]

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

Appendices A – D

Appendix A – 2014 Reliability Needs Assessment Glossary

Term	Definition
10-year Study Period	10-year period starting with the year after the study is dated and projecting forward 10 years. For example, the 2014 RNA covers the 10-year Study Period of 2015 through 2024.
Adequacy	Encompassing both generation and transmission, adequacy refers to the ability of the bulk power system to supply the aggregate requirements of consumers at all times, accounting for scheduled and unscheduled outages of system components.
Alternative Regulated Solutions	Regulated solutions submitted by a TO or other developer in response to a solicitation by the ARS, if the NYISO determines that there is a Reliability Need.
Annual Transmission Reliability Assessment (ATRA)	An assessment, conducted by the NYISO staff in cooperation with Market Participants, to determine the System Upgrade Facilities required for each generation and merchant transmission project included in the Applicable Reliability Standards, to interconnect to the New York State Transmission System in compliance with Applicable Reliability Standards and the NYISO Minimum Interconnection Standard.
Area Transmission Review (ATR)	The NYISO, in its role as Planning Coordinator, is responsible for providing an annual report to the NPCC Compliance Committee in regard to its Area Transmission Review in accordance with the NPCC Reliability Compliance and Enforcement Program and in conformance with the NPCC Design and Operation of the Bulk Power System (Directory #1).
Best Available Retrofit Technology (BART)	NYS DEC regulation, required for compliance with the federal Clean Air Act, applying to fossil fueled electric generating units built between August 7, 1962 and August 7, 1977. Emissions control of SO_2, NOx and PM may be necessary for compliance. Compliance deadline is January 2014.
Best Technology Available (BTA)	NYS DEC policy establishing performance goals for new and existing electricity generating plants for Cooling Water Intake Structures. The policy would apply to plants with design intake capacity greater than 20 million gallons/day and prescribes reductions in fish mortality. The performance goals call for the use of wet, closed-cycle cooling systems at existing generating plants.
New York State Bulk Power Transmission Facility (BPTF)	The facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to NPCC by the ISO pursuant to NPCC requirements.
Capability Period	The Summer Capability Period lasts six months, from May 1 through

Term	Definition
	October 31. The Winter Capability Period runs from November 1 through April 30 of the following year.
Capacity	The capability to generate or transmit electrical power, or the ability to reduce demand at the direction of the NYISO.
Capacity Resource Integration Service (CRIS)	CRIS is the service provided by NYISO to interconnect the Developer's Large Generating Facility or Merchant Transmission Facility to the New York State Transmission System in accordance with the NYISO Deliverability Interconnection Standard, to enable the New York State Transmission System to deliver electric capacity from the Large Generating Facility or Merchant Transmission Facility, pursuant to the terms of the NYISO OATT.
Class Year	The group of generation and merchant transmission projects included in any particular Annual Transmission Reliability Assessment (ATRA), in accordance with the criteria specified for including such projects in the assessment.
Clean Air Interstate Rule (CAIR)	USEPA rule to reduce interstate transport of fine particulate matter (PM) and ozone. CAIR provides a federal framework to limit the emission of SO_2 and NOx.
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 or other developers to pursue alternative regulated solutions to meet Reliability Needs, if market-based solutions will not be available by the need date. It is the second step in the Reliability Planning Process (RPP).
Comprehensive System Planning Process (CSPP)	A transmission system planning process that is comprised of three components: 1) Local transmission owner planning; 2) Compilation of local plans into the Reliability Planning Process (RPP), which includes developing a Comprehensive Reliability Plan (CRP); 3) Channeling the CRP data into the Congestion Assessment and Resource Integration Study (CARIS)
Congestion Assessment and Resource Integration Study (CARIS)	The third component of the Comprehensive System Planning Process (CSPP). The CARIS is based on the Comprehensive Reliability Plan (CRP).
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.

Term	Definition
Contingencies	Contingencies are individual electrical system events (including disturbances and equipment failures) that are likely to happen.
Cross-State Air Pollution Rule (CSARP)	This USEPA rule requires the reduction of power plant emissions that contribute to exceedances of ozone and/or fine particle standards in other states.
Dependable Maximum Net Capability (DMNC)	The sustained maximum net output of a generator, as demonstrated by the performance of a test or through actual operation, averaged over a continuous time period as defined in the ISO Procedures. The DMNC test determines the amount of Installed Capacity used to calculate the Unforced Capacity that the Resource is permitted to supply to the NYCA.
Electric System Planning Work 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 regulated reliability and/or economic projects, and related matters.
Energy Efficiency Portfolio Standard (EEPS)	A statewide program ordered by the NYDPS in response to the Governor's call to reduce New Yorkers' electricity usage by 15% of 2007 forecast levels by the year 2015, with comparable results in natural gas conservation.
Federal Energy Regulatory Commission (FERC)	The federal energy regulatory agency within the U.S. 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 715	Annual report that is required by transmitting utilities operating grid facilities that are rated at or above 100 kilovolts. The report consists of transmission systems maps, a detailed description of transmission planning Reliability Criteria, detailed descriptions of transmission planning assessment practices, and detailed evaluation of anticipated system performance as measured against Reliability Criteria.
Forced Outage	An unanticipated loss of capacity due to the breakdown of a power plant or transmission line. It can also mean the intentional shutdown of a generating unit or transmission line for emergency reasons.
Gap Solution	A solution to a Reliability Need that is designed to be temporary and to strive to be compatible with permanent market-based proposals. A permanent regulated solution, if appropriate, may proceed in parallel with a Gap Solution. The NYISO may call for a Gap Solution to

Term	Definition
	an imminent threat to reliability of the Bulk Power Transmission Facilities if no market-based solutions, regulated backstop solutions, or alternative regulated solutions can meet the Reliability Needs in a timely manner.
Gold Book	Annual NYISO publication of its Load and Capacity Data Report.
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. The Installed Capacity requirement, established by the New York State Reliability Council (NYSRC), includes a margin of reserve in accordance with the Reliability Rules.
Installed Reserve Margin (IRM)	The amount of installed electric generation capacity above 100% of the forecasted peak electric demand that is required to meet NYSRC resource adequacy criteria. Most studies in recent years have indicated a need for a 15-20% reserve margin for adequate reliability in New York.
Interconnection Queue	A queue of transmission and generation projects that have submitted an Interconnection Request to the NYISO to be interconnected to the New York State Transmission System. All projects must undergo three studies – a Feasibility Study (unless parties agree not to perform it), a System Reliability Impact Study (SRIS) and a Facilities Study – before interconnecting to the grid.
Local Transmission Plan (LTP)	The Local Transmission Owner Plan, developed by each Transmission Owner, which describes its respective plans that may be under consideration or finalized for its own Transmission District.
Local Transmission Owner Planning Process (LTPP)	The first step in the Comprehensive System Planning Process (CSPP), under which transmission owners in New York's electricity markets provide their local transmission plans for consideration and comment by interested parties.
Loss of load expectation (LOLE)	LOLE establishes the amount of generation and demand-side resources needed - subject to the level of the availability of those resources, load uncertainty, available transmission system transfer capability and emergency operating procedures - to minimize the probability of an involuntary loss of firm electric load on the bulk electricity grid. The state's bulk electricity grid is designed to meet an LOLE that is not greater than one occurrence of an involuntary load disconnection in 10 years, expressed mathematically as 0.1 days per year.
Market-Based Solutions	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

Term	Definition
	demand response Programs.
Market Monitoring Unit	A consulting or other professional services firm, or other similar entity, retained by the NYISO Board pursuant to ISO Services Tariff Section 30.4.6.8.1, Attachment O - Market Monitoring Plan.
Market Participant	An entity, excluding the ISO, that produces, transmits, sells, and/or purchases for resale Capacity, Energy and Ancillary Services in the Wholesale Market. Market Participants include: Transmission Customers under the ISO OATT, Customers under the ISO Services Tariff, Power Exchanges, Transmission Owners, Primary Holders, LSEs, Suppliers and their designated agents. Market Participants also include entities buying or selling TCCs.
Mercury and Air Toxics Standards (MATS)	The rule applies to oil and coal fired generators and establishes limits for HAPs, acid gases, mercury (Hg), and particulate matter (PM). Compliance is required by March 2015, with extensions to 2017 for reliability critical units.
Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units (MRP)	NYSDEC regulation of mercury emissions from coal-fired electric utility steam generating units with a nameplate capacity of more than 25 MW producing electricity for sale.
National Ambient Air Quality Standards (NAAQS)	Limits, set by the EPA, on pollutants considered harmful to public health and the environment.
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 State Department of Environmental Conservation (NYSDEC)	The agency that implements New York State environmental conservation law, with some programs also governed by federal law.
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 – an 11,056-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 Department of Public Service	As defined in the New York Public Service Law, it serves as the staff for the New York State Public Service Commission.

Term	Definition
(NYDPS)	
New York State Energy Research and Development Authority (NYSERDA)	A corporation created under the New York State Public Authorities law and funded by the System Benefits Charge (SBC) and other sources. Among other responsibilities, NYSERDA is charged with conducting a multifaceted energy and environmental research and development program to meet New York State's diverse economic needs, and administering state System Benefits Charge, Renewable Portfolio Standard, and Energy Efficiency Portfolio Standard programs.
New York State Public Service Commission (NYPSC)	The New York State Public Service Commission is the decision making body of the New York State Department of Public Service. The PSC regulates the state's electric, gas, steam, telecommunications, and water utilities and oversees the cable industry. The Commission has the responsibility for setting rates and ensuring that safe and adequate service is provided by New York's utilities. In addition, the Commission exercises jurisdiction over the siting of major gas and electric transmission facilities
New York State Reliability Council (NYSRC)	A not-for-profit entity that develops, maintains, and, from time-to-time, updates 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.
North American Electric Reliability Corporation (NERC)	A not-for-profit organization that develops and enforces reliability standards; assesses reliability annually via 10-year and seasonal forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is subject to oversight by the FERC and governmental authorities in Canada.
Northeast Power Coordinating Council (NPCC)	A not-for-profit corporation responsible for promoting and improving the reliability of the international, interconnected bulk power system in Northeastern North America.
Open Access Transmission Tariff (OATT)	Document of Rates, Terms and Conditions, regulated by the FERC, under which the NYISO provides transmission service. The OATT is a dynamic document to which revisions are made on a collaborative basis by the NYISO, New York's Electricity Market Stakeholders, and the FERC.
Order 890	Adopted by FERC in February 2007, Order 890 is a change to FERC's 1996 transmission 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-

Term	Definition
	discriminatory transmission service. Order 890 requires Transmission Providers – including the NYISO – to have a formal planning process that provides for a coordinated transmission planning process, including reliability and economic planning studies.
Order 1000	Order No. 1000 is a Final Rule that reforms the FERC electric transmission planning and cost allocation requirements for public utility transmission providers. The rule builds on the reforms of Order No. 890 and provides for transmission planning to meet transmission needs driven by Public Policy Requirements, interregional planning, opens transmission development for new transmission needs to non-incumbent developers, and provides for cost allocation and recovery of transmission upgrades.
Outage	The forced or scheduled removal of generating capacity or a transmission line from service.
Peak Demand	The maximum instantaneous power demand, measured in megawatts (MW), and also known as peak load, is usually measured and averaged over an hourly interval.
Reasonably Available Control Technology for Oxides of Nitrogen (NOx RACT)	Regulations promulgated by NYSDEC for the control of emissions of nitrogen oxides (NOx) from fossil fueled power plants. The regulations establish presumptive emission limits for each type of fossil fueled generator and fuel used as an electric generator in NY. The NOx RACT limits are part of the State Implementation Plan for achieving compliance with the National Ambient Air Quality Standard (NAAQS) for ozone.
Reactive Power Resources	Facilities such as generators, high voltage transmission lines, synchronous condensers, capacitor banks, and static VAr compensators that provide reactive power. Reactive power is the portion of electric power that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power is usually expressed as kilovolt-amperes reactive (kVAr) or megavolt-ampere reactive (MVAr).
Regional Greenhouse Gas Initiative (RGGI)	A cooperative effort by nine Northeast and Mid-Atlantic states (not including New Jersey or Pennsylvania) to limit greenhouse gas emissions using a market-based cap-and-trade approach.
Regulated Backstop Solutions	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.
Reliability Criteria	The electric power system planning and operating policies, standards, criteria, guidelines, procedures, and rules promulgated by the North American Electric Reliability Corporation (NERC), Northeast Power

Term	Definition
	Coordinating Council (NPCC), and the New York State Reliability Council (NYSRC), as they may be amended from time to time.
Reliability Need	A condition identified by the NYISO in the RNA as a violation or potential violation of Reliability Criteria.
Reliability Needs Assessment (RNA)	A biennial study which evaluates the resource adequacy and transmission system adequacy and security of the New York bulk power system over a ten year Study Period. Through this evaluation, the NYISO identifies Reliability Needs in accordance with applicable Reliability Criteria.
Reliability Planning Process (RPP)	The biennial process that includes evaluation of resource adequacy and transmission system security of the state's bulk electricity grid over a 10-year period and evaluates solutions to meet those needs. The RPP consists of two studies: the RNA, which identifies potential problems, and the CRP, which evaluates specific solutions to those problems.
Renewable Portfolio Standard (RPS)	Proceeding commenced by order of the NYDPS in 2004 which established the goal to increase renewable energy used in New York State to 30% of total New York energy usage (equivalent to approximately 3,700 MW of capacity) by 2015.
Responsible Transmission Owner (Responsible TO)	The Transmission Owner(s) or TOs designated by the NYISO, pursuant to the NYISO RPP, to prepare a proposal for a regulated solution to a Reliability Need or to proceed with a regulated solution to a Reliability Need. The Responsible TO will normally be the Transmission Owner in whose Transmission District the NYISO identifies a Reliability Need.
Security	The ability of the power system to withstand the loss of one or more elements without involuntarily disconnecting firm load.
Special Case Resources (SCR)	A NYISO 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 as SCRs are paid in advance for agreeing to cut power upon NYISO request.
State Environmental Quality Review Act (SEQRA)	NYS law requiring the sponsoring or approving governmental body to identify and mitigate the significant environmental impacts of the activity/project it is proposing or permitting.
Study Period	The 10-year time period evaluated in the RNA.
System Reliability Impact Study (SRIS)	A study, conducted by the NYISO in accordance with Applicable Reliability Standards, to evaluate the impact of a proposed interconnection on the reliability of the New York State Transmission System.
System Benefits	An amount of money, charged to ratepayers on their electric bills,

Term	Definition
Charge (SBC)	which is administered and allocated by NYSERDA towards energy-efficiency programs, research and development initiatives, low-income energy programs, and environmental disclosure activities.
Transfer Capability	The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission facilities (or paths) between those areas under specified system conditions.
Transmission Constraints	Limitations on the ability of a transmission system to transfer electricity during normal or emergency system conditions.
Transmission Owner (TO)	A public utility or authority that owns transmission facilities and provides Transmission Service under the NYISO's tariffs
Transmission Planning Advisory Subcommittee (TPAS)	An identified 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
Unforced Capacity Delivery Rights (UDR)	Unforced capacity delivery rights are rights that may be granted to controllable lines to deliver generating capacity from locations outside the NYCA to localities within NYCA.
Weather Normalized	Adjustments made to normalize the impact of weather when making energy and peak demand forecasts. Using historical weather data, energy analysts can account for the influence of extreme weather conditions and adjust actual energy use and peak demand to estimate what would have happened if the hottest day or the coldest day had been the typical, or "normal," weather conditions. "Normal" is usually calculated by taking the average of the previous 20 years of weather data.
Zone	One of the eleven regions in the NYCA connected to each other by identified transmission interfaces and designated as Load Zones A-K.

Appendix B - The Reliability Planning Process

This section presents an overview of the NYISO reliability planning process (RPP). A detailed discussion of the reliability planning process, including applicable Reliability Criteria, is contained in NYISO Manual entitled: “Reliability Planning Process Manual,” which is posted on the NYISO’s website.

The NYISO reliability planning process is an integral part of the NYISO’s overall Comprehensive System Planning Process (CSPP). The CSPP planning process is comprised of the Local Transmission Planning Process (LTPP), the RPP, and the Congestion Assessment and Resource Integration Study (CARIS). Each CSPP cycle begins with the LTPP. As part of the LTPP, local Transmission Owners perform transmission studies for their BPTFs in their transmission areas according to all applicable criteria. Links to the Transmission Owner’s LTPs can be found on the NYISO’s website. The LTPP provides inputs for the NYISO’s reliability planning process. During the RPP process, the NYISO conducts the Reliability Needs Assessment (RNA) and Comprehensive Reliability Plan (CRP). The RNA evaluates the adequacy and security of the bulk power system over a 10-year study period. In identifying resource adequacy needs, the NYISO identifies the amount of resources in megawatts (known as “compensatory megawatts”) and the locations in which they are needed to meet those needs. After the RNA is complete, the NYISO requests and evaluates market-based solutions, regulated backstop solutions and alternative regulated solutions that address the identified Reliability Needs. This step results in the development of the NYISO’s CRP for the 10-year study period. The CRP provides inputs for the NYISO’s economic planning process known as CARIS. CARIS Phase 1 examines congestion on the New York bulk power system and the costs and benefits of alternatives to alleviate that congestion. During CARIS Phase 2, the NYISO will evaluate specific transmission project proposals for regulated cost recovery.

The NYISO’s reliability planning process is a long-range assessment of both resource adequacy and transmission reliability of the New York bulk power system conducted over a 10-year planning horizon. There are two different aspects to analyzing the bulk power system’s reliability in the RNA: adequacy and security. Adequacy is a planning and probabilistic concept. A system is adequate if the probability of having sufficient transmission and generation to meet expected demand is equal to or less than the system’s standard, which is expressed as a loss of load expectation (LOLE). The New York State bulk power system is planned to meet an LOLE that, at any given point in time, is less than or equal to an involuntary load disconnection that is not more frequent than once in every 10 years, or 0.1 days per year. This requirement forms the basis of New York’s installed reserve margin (IRM) resource adequacy requirement.

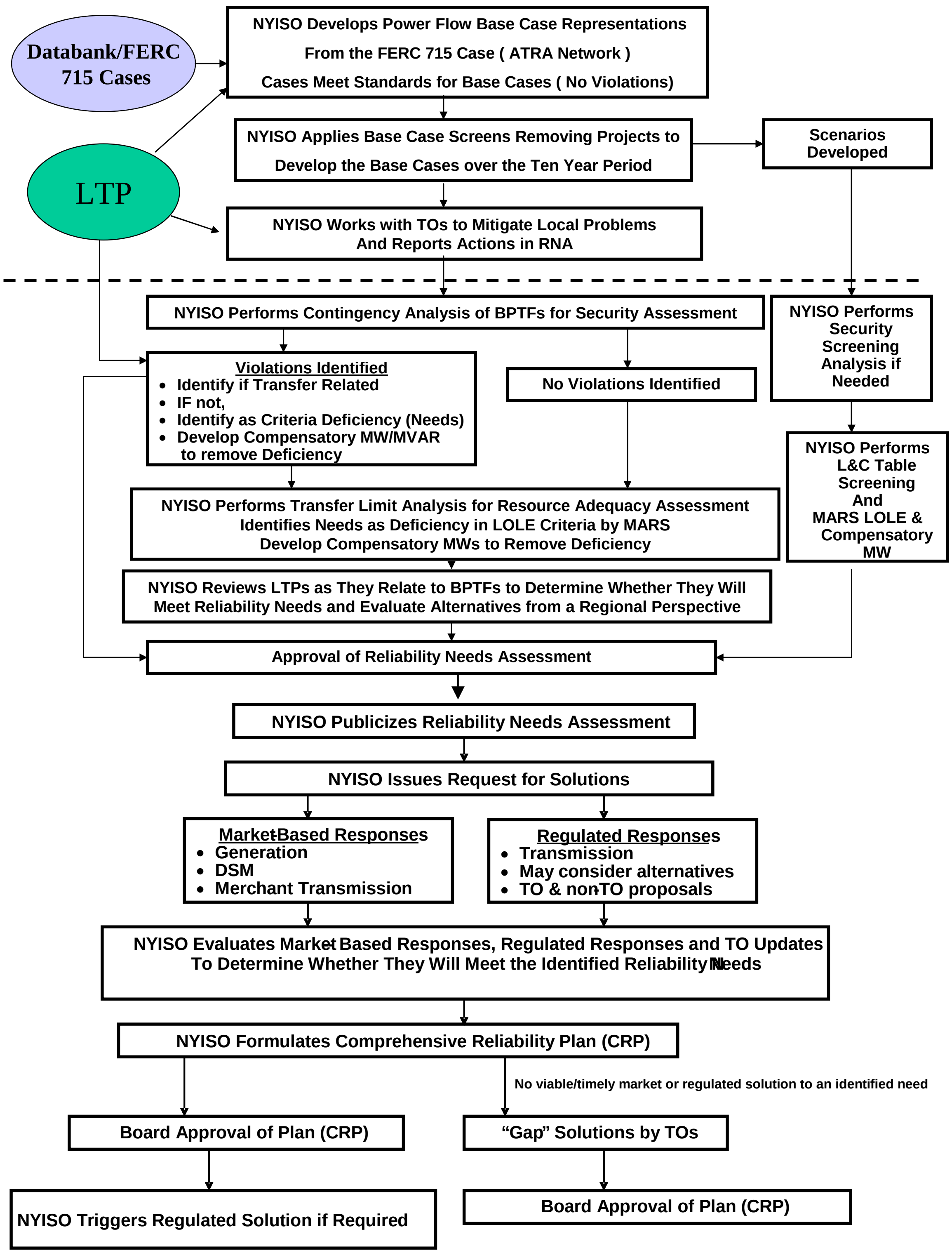
Security is an operating and deterministic concept. This means that possible events are identified as having significant adverse reliability consequences, and the system is planned and operated so that the system can continue to serve load even if these events occur. Security requirements are sometimes referred to as N-1 or N-1-1. N is the number of system components; an N-1 requirement means that the system can withstand single disturbance events (e.g., generator, bus section, transmission circuit, breaker failure, double-circuit tower) without violating thermal, voltage and stability limits or before affecting service to consumers. An N-1-1 requirement means that the Reliability Criteria apply after any critical element such as a generator, a transmission circuit, a transformer, series or shunt compensating device, or a high voltage direct current (HVDC) pole has already been lost. Generation and power flows can be adjusted by the use of 10-minute operating reserve, phase angle regulator control and HVDC control and a second single disturbance is analyzed.

The RPP is anchored in the market-based philosophy of the NYISO and its Market Participants, which posits that market solutions should be the preferred choice to meet the identified Reliability Needs reported in the RNA. In the CRP, the reliability of the bulk power system is assessed and solutions to Reliability Needs evaluated in accordance with existing Reliability Criteria of the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council, Inc. (NPCC), and the New York State Reliability Council (NYSRC) as they may change from time to time. These criteria and a description of the nature of long-term bulk power system planning are described in detail in the applicable planning manual, and are briefly summarized below. In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the NYISO designates the Responsible TO or Responsible TOs or developer of an alternative regulated solution to proceed with a regulated solution in order to maintain system reliability. Under the RPP, the NYISO also has an affirmative obligation to report historic congestion across the transmission system. In addition, the draft RNA is provided to the Market Monitoring Unit for review and consideration of whether market rules changes are necessary to address an identified failure, if any, in one of the NYISO's competitive markets. If market failure is identified as the reason for the lack of market-based solutions, the NYISO will explore appropriate changes in its market rules with its stakeholders and Independent Market Monitor. The RPP does not substitute for the planning that each TO conducts to maintain the reliability of its own bulk and non-bulk power systems.

The NYISO does not license or construct projects to respond to identified Reliability Needs reported in the RNA. The ultimate approval of those projects lies with regulatory agencies such as the FERC, the NYDPS, environmental permitting agencies, and local governments. The NYISO monitors the progress and continued viability of proposed market and regulated projects to meet identified needs, and reports its findings in annual plans. Figure B-1 below summarizes the RPP and Figure B-2 summarizes the CARIS which collectively comprise the CSPP process.

The CRP will form the basis for the next cycle of the NYISO's economic planning process. That process will examine congestion on the New York bulk power system and the costs and benefits of alternatives to alleviate that congestion.

NYISO Reliability Planning Process



Appendix C - Load and Energy Forecast 2014-2024

C-1. Summary

In order to perform the 2014 RNA, a forecast of summer and winter peak demands and annual energy requirements was produced for the years 2014 - 2024. The electricity forecast is based on projections of New York's economy performed by Moody's Analytics in January 2014. The forecast includes detailed projections of employment, output, income and other factors for twenty three regions in New York State. This appendix provides a summary of the electric energy and peak demand forecasts and the key economic input variables used to produce the forecasts. Table C-1 provides a summary of key economic and electric system growth rates from 2003 to 2024.

In June 2008, the New York Public Service Commission issued its Order regarding the Energy Efficiency Portfolio Standard. This proceeding set forth a statewide goal of a cumulative energy reduction of about 26,900 GWh. The NYISO estimates the peak demand impacts to be about 5500 MW. This goal is expected to be achieved by contributions from a number of state agencies, power authorities and utilities, as well as from federal codes and building standards.

Table C-1: Summary of Economic & Electric System Growth Rates – Actual & Forecast

	Average Annual Growth			
	2003-2008	2008-2013	2014-2019	2019-2024
Total Employment	0.70%	0.52%	0.93%	0.21%
Gross State Product	1.58%	1.85%	2.47%	1.75%
Population	0.08%	0.34%	0.19%	0.14%
Total Real_Income	2.53%	1.59%	2.77%	2.25%
Weather Normalized Summer Peak	1.40%	-0.10%	1.04%	0.63%
Weather Normalized Annual Energy	1.11%	-0.36%	0.14%	0.17%

C-2. Historic Overview

The New York Control Area (NYCA) is a summer peaking system and its summer peak has grown faster than annual energy and winter peak over this period. Both summer and winter peaks show considerable year-to-year variability due to the influence of peak-producing weather conditions for the seasonal peaks. Annual energy is influenced by weather conditions over the entire year, which is much less variable than peak-producing conditions.

Table C-2 shows the NYCA historic seasonal peaks and annual energy growth since 2001. The table provides both actual results and weather-normalized results, together with annual average growth rates for each table entry. The growth rates are averaged over the period 2003 to 2013.

Table C-2: Historic Energy and Seasonal Peak Demand - Actual and Weather-Normalized

	Annual Energy - GWh		Summer Peak - MW		Winter Peak - MW		
Year	Actual	Weather Normalized	Actual	Weather Normalized	Year	Actual	Weather Normalized
2003	158,130	157,523	30,333	31,410	2003-04	25,262	24,849
2004	160,211	160,832	28,433	31,401	2004-05	25,541	25,006
2005	167,207	163,015	32,075	33,068	2005-06	24,947	24,770
2006	162,237	163,413	33,939	32,992	2006-07	25,057	25,030
2007	167,339	166,173	32,169	33,444	2007-08	25,021	25,490
2008	165,613	166,468	32,432	33,670	2008-09	24,673	25,016
2009	158,777	161,908	30,844	33,063	2009-10	24,074	24,537
2010	163,505	161,513	33,452	32,458	2010-11	24,654	24,452
2011	163,330	162,628	33,865	33,019	2011-12	23,901	24,630
2012	162,843	163,458	32,547	33,106	2012-13	24,658	24,630
2013	163,493	163,473	33,956	33,502	2013-14	25,738	24,610
	0.33%	0.37%	1.13%	0.65%		0.19%	-0.10%

C-3. Forecast Overview

Table C-3 shows historic and forecast growth rates of annual energy for the different regions in New York. The Upstate region includes Zones A – I. The NYCA's two locality zones, Zones J (New York City) and K (Long Island) are shown individually.

Table C-3: Annual Energy and Summer Peak Demand - Actual & Forecast

	Annual Energy - GWh				Summer Coincident Peak - MW			
Year	Upstate Region	J	K	NYCA	Upstate Region	J	K	NYCA
2003	85,223	50,829	21,960	158,012	15,100	10,240	4,993	30,333
2004	85,935	52,073	22,203	160,211	14,271	9,742	4,420	28,433
2005	90,253	54,007	22,948	167,208	16,029	10,810	5,236	32,075
2006	86,957	53,096	22,185	162,238	17,054	11,300	5,585	33,939
2007	89,843	54,750	22,748	167,341	15,824	10,970	5,375	32,169
2008	88,316	54,835	22,461	165,612	16,223	10,979	5,231	32,433
2009	83,788	53,100	21,892	158,780	15,416	10,366	5,063	30,845
2010	85,469	55,114	22,922	163,505	16,408	11,213	5,832	33,453
2011	86,566	54,059	22,704	163,329	16,558	11,374	5,935	33,867
2012	87,051	53,487	22,302	162,840	16,608	10,722	5,109	32,439
2013	88,084	53,316	22,114	163,514	16,847	11,456	5,653	33,956
2014	87,456	53,498	22,207	163,161	16,621	11,643	5,402	33,666
2015	87,602	53,284	22,328	163,214	16,711	11,907	5,448	34,066
2016	87,983	53,402	22,522	163,907	16,850	12,070	5,492	34,412
2017	87,870	53,144	22,590	163,604	16,996	12,238	5,532	34,766
2018	87,987	53,046	22,720	163,753	17,120	12,421	5,570	35,111
2019	88,515	52,940	22,850	164,305	17,296	12,549	5,609	35,454
2020	89,089	52,969	23,043	165,101	17,369	12,638	5,649	35,656
2021	88,993	52,727	23,110	164,830	17,453	12,747	5,690	35,890
2022	89,113	52,622	23,240	164,975	17,560	12,836	5,731	36,127
2023	89,222	52,517	23,370	165,109	17,647	12,945	5,777	36,369
2024	89,600	52,556	23,565	165,721	17,730	13,029	5,821	36,580
2003-13	0.3%	0.5%	0.1%	0.3%	1.1%	1.1%	1.2%	1.1%
2014-24	0.2%	-0.2%	0.6%	0.2%	0.6%	1.1%	0.7%	0.8%
2003-08	0.7%	1.5%	0.5%	0.9%	1.4%	1.4%	0.9%	1.3%
2008-13	-0.1%	-0.6%	-0.3%	-0.3%	0.8%	0.9%	1.6%	0.9%
2014-19	0.2%	-0.2%	0.6%	0.1%	0.8%	1.5%	0.8%	1.0%
2019-24	0.2%	-0.1%	0.6%	0.2%	0.5%	0.8%	0.7%	0.6%

C-4. Forecast Methodology

The NYISO methodology for producing the long term forecasts for the Reliability Needs Assessment consists of the following steps.

Econometric forecasts were developed for zonal energy using monthly data from 2000 through 2013. For each zone, the NYISO estimated an ensemble of econometric models using population, households, economic output, employment, cooling degree days and heating degree days. Each member of the ensemble was evaluated and compared to historic data. The zonal model chosen for the forecast was the one which best represented recent history and the regional growth for that zone. The NYISO also received and evaluated forecasts from Con Edison and LIPA, which were used in combination with the forecasts we developed for Zones H, I, J and K.

The summer & winter non-coincident and coincident peak forecasts for Zones H, I, J and K were derived from the forecasts submitted to the NYISO by Con Edison and LIPA. For the remaining zones, the NYISO derived the summer and winter coincident peak demands from the zonal energy forecasts by using average zonal weather-normalized load factors from 2000 through 2013. The 2014 summer peak forecast was matched to coincide with the 2014 ICAP forecast.

C-4.1. Demand Side Initiatives

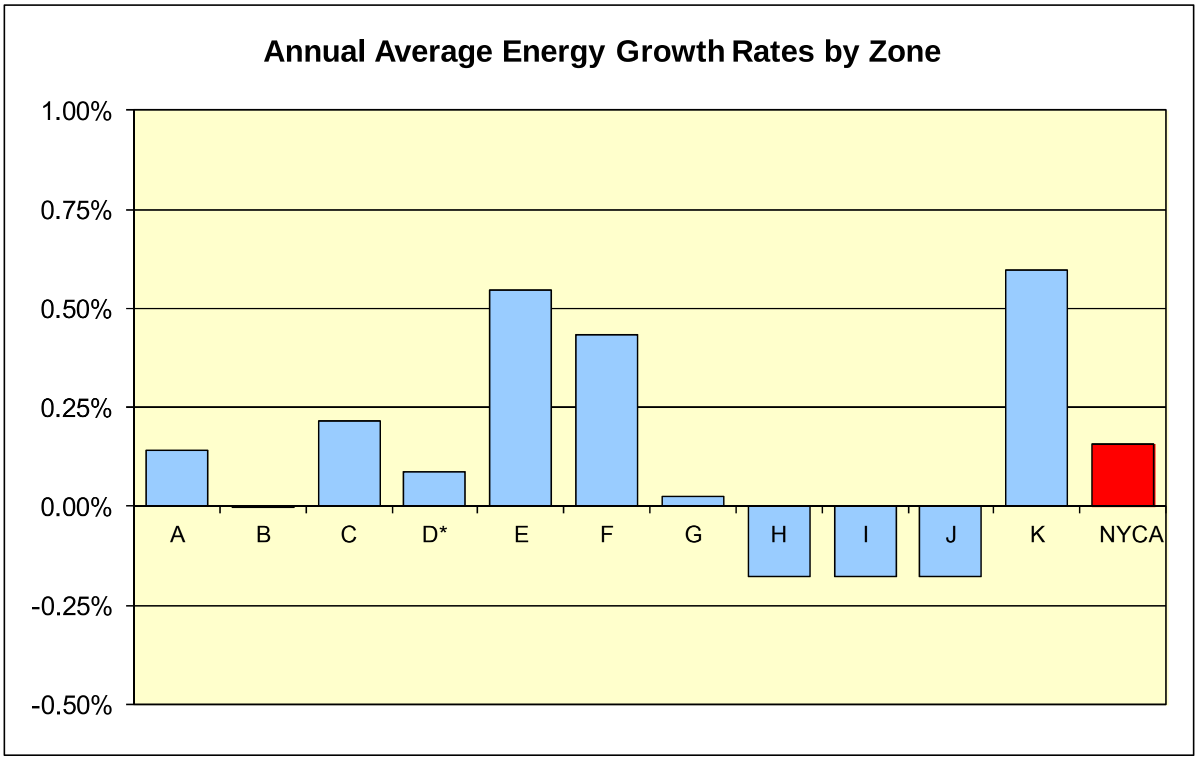
The Energy Efficiency Portfolio Standard (EEPS) is an initiative of the Governor of New York and implemented by the state's Public Service Commission. The goal of the initiative is to reduce electric energy usage by 15 percent from 2007 forecasted energy usage levels in the year 2015 (the 15x15 initiative), for a reduction of 26,880 GWh by 2015.

The NYS PSC directed a series of working groups composed of all interested parties to the proceeding to obtain information needed to further elaborate the goal. The NYS PSC issued an Order in June 2008, directing NYSERDA and the state's investor owned utilities to develop conservation plans in accordance with the EEPS goal. The NYS PSC also identified goals that it expected would be implemented by LIPA and NYPA.

The NYISO has been a party to the EEPS proceeding from its inception. As part of the development of the 2014 RNA forecast, the NYISO developed an adjustment to the 2014 econometric model that incorporated a portion of the EEPS goal. This was based upon discussion with market participants in the Electric System Planning Working Group. The NYISO considered the following factors in developing the 2014 RNA base case:

- NYS PSC-approved spending levels for the programs under its jurisdiction, including the Systems Benefit Charge and utility-specific programs
- Expected realization rates, participation rates and timing of planned energy efficiency programs
- Degree to which energy efficiency is already included in the NYISO's econometric energy forecast
- Impacts of new appliance efficiency standards, and building codes and standards
- Specific energy efficiency plans proposed by LIPA, NYPA and Consolidated Edison Company of New York, Inc. (Con Edison)
- The actual rates of implementation of EEPS based on data received from Department of Public Service staff
- Projected impact of customer-sited solar photovoltaic installations

Once the statewide energy and demand impacts were developed, zonal level forecasts were produced for the econometric forecast and for the base case.



* Zone D's average energy and peak demand growth is based on the last four years of the forecast, after industrial load in this zone is expected to return from a curtailment.

Figure C-1: Zonal Energy Forecast Growth Rates - 2014 to 2024

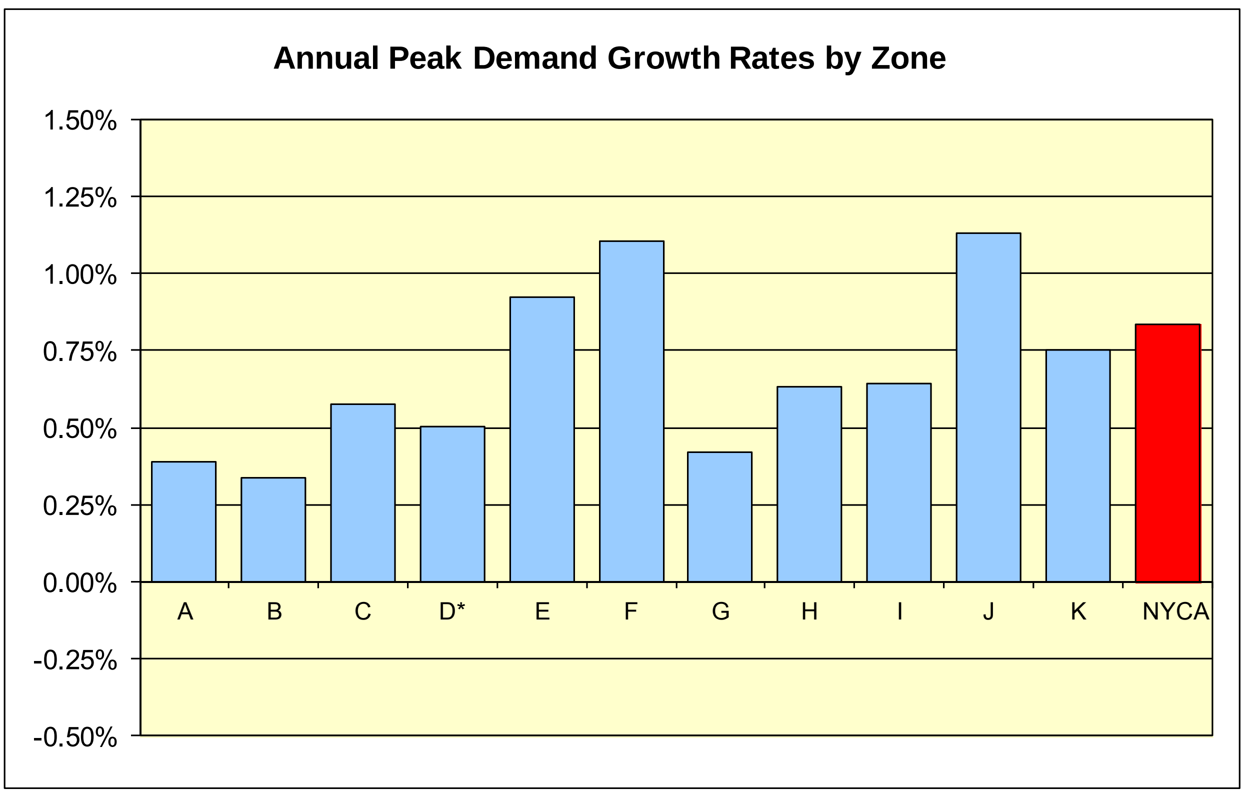


Figure C-2: Zonal Summer Peak Demand Forecast Growth Rates - 2014 to 2024

Table C-4: Annual Energy by Zone – Actual & Forecast (GWh)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2003	15,942	9,719	16,794	5,912	6,950	11,115	10,451	2,219	6,121	50,829	21,960	158,012
2004	16,102	9,888	16,825	5,758	7,101	11,161	10,696	2,188	6,216	52,073	22,203	160,211
2005	16,498	10,227	17,568	6,593	7,594	11,789	10,924	2,625	6,435	54,007	22,948	167,208
2006	15,998	10,003	16,839	6,289	7,339	11,337	10,417	2,461	6,274	53,096	22,185	162,238
2007	16,258	10,207	17,028	6,641	7,837	11,917	10,909	2,702	6,344	54,750	22,748	167,341
2008	15,835	10,089	16,721	6,734	7,856	11,595	10,607	2,935	5,944	54,835	22,461	165,612
2009	15,149	9,860	15,949	5,140	7,893	10,991	10,189	2,917	5,700	53,100	21,892	158,780
2010	15,903	10,128	16,209	4,312	7,906	11,394	10,384	2,969	6,264	55,114	22,922	163,505
2011	16,017	10,040	16,167	5,903	7,752	11,435	10,066	2,978	6,208	54,059	22,704	163,329
2012	15,595	10,009	16,117	6,574	7,943	11,846	9,938	2,930	6,099	53,487	22,302	162,840
2013	15,790	9,981	16,368	6,448	8,312	12,030	9,965	2,986	6,204	53,316	22,114	163,514
2014	15,837	10,011	16,342	6,027	8,153	11,993	9,979	2,957	6,157	53,498	22,207	163,161
2015	15,870	10,005	16,372	6,042	8,167	12,043	10,025	2,946	6,132	53,284	22,328	163,214
2016	15,942	10,025	16,441	6,072	8,214	12,128	10,062	2,953	6,146	53,402	22,522	163,907
2017	15,913	9,993	16,423	6,066	8,233	12,148	10,040	2,938	6,116	53,144	22,590	163,604
2018	15,925	9,988	16,447	6,075	8,277	12,201	10,038	2,931	6,105	53,046	22,720	163,753
2019	15,942	9,985	16,475	6,493	8,319	12,256	10,026	2,927	6,092	52,940	22,850	164,305
2020	16,012	10,009	16,553	6,721	8,395	12,334	10,042	2,927	6,096	52,969	23,043	165,101
2021	15,988	9,980	16,546	6,711	8,431	12,345	10,008	2,916	6,068	52,727	23,110	164,830
2022	15,998	9,979	16,583	6,717	8,480	12,391	9,999	2,910	6,056	52,622	23,240	164,975
2023	16,007	9,979	16,615	6,722	8,524	12,439	9,989	2,903	6,044	52,517	23,370	165,109
2024	16,060	10,009	16,696	6,744	8,608	12,525	10,004	2,905	6,049	52,556	23,565	165,721

Table C-5: Summer Coincident Peak Demand by Zone – Actual & Forecast (MW)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2003	2,510	1,782	2,727	671	1,208	2,163	2,146	498	1,395	10,240	4,993	30,333
2004	2,493	1,743	2,585	644	1,057	1,953	2,041	475	1,280	9,742	4,420	28,433
2005	2,726	1,923	2,897	768	1,314	2,164	2,236	592	1,409	10,810	5,236	32,075
2006	2,735	2,110	3,128	767	1,435	2,380	2,436	596	1,467	11,300	5,585	33,939
2007	2,592	1,860	2,786	795	1,257	2,185	2,316	595	1,438	10,970	5,375	32,169
2008	2,611	2,001	2,939	801	1,268	2,270	2,277	657	1,399	10,979	5,231	32,433
2009	2,595	1,939	2,780	536	1,351	2,181	2,159	596	1,279	10,366	5,063	30,845
2010	2,663	1,985	2,846	552	1,437	2,339	2,399	700	1,487	11,213	5,832	33,453
2011	2,556	2,019	2,872	776	1,447	2,233	2,415	730	1,510	11,374	5,935	33,867
2012	2,743	2,107	2,888	774	1,420	2,388	2,242	653	1,393	10,722	5,109	32,439
2013	2,549	2,030	2,921	819	1,540	2,392	2,358	721	1,517	11,456	5,653	33,956
2014	2,674	2,054	2,896	703	1,434	2,374	2,290	689	1,507	11,643	5,402	33,666
2015	2,688	2,062	2,916	705	1,449	2,405	2,309	684	1,493	11,907	5,448	34,066
2016	2,710	2,077	2,942	707	1,464	2,437	2,324	688	1,501	12,070	5,492	34,412
2017	2,733	2,093	2,972	710	1,483	2,475	2,336	688	1,506	12,238	5,532	34,766
2018	2,748	2,103	2,993	715	1,499	2,503	2,347	694	1,518	12,421	5,570	35,111
2019	2,756	2,110	3,009	789	1,512	2,529	2,355	702	1,534	12,549	5,609	35,454
2020	2,763	2,112	3,020	793	1,523	2,547	2,363	706	1,542	12,638	5,649	35,656
2021	2,769	2,115	3,033	797	1,536	2,570	2,370	709	1,554	12,747	5,690	35,890
2022	2,773	2,117	3,044	801	1,547	2,595	2,377	724	1,582	12,836	5,731	36,127
2023	2,777	2,121	3,055	805	1,558	2,624	2,383	730	1,594	12,945	5,777	36,369
2024	2,780	2,124	3,067	809	1,572	2,649	2,388	734	1,607	13,029	5,821	36,580

Table C-6: Winter Coincident Peak Demand by Zone – Actual & Forecast (MW)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2003-04	2,433	1,576	2,755	857	1,344	1,944	1,720	478	981	7,527	3,647	25,262
2004-05	2,446	1,609	2,747	918	1,281	1,937	1,766	474	939	7,695	3,729	25,541
2005-06	2,450	1,544	2,700	890	1,266	1,886	1,663	515	955	7,497	3,581	24,947
2006-07	2,382	1,566	2,755	921	1,274	1,888	1,638	504	944	7,680	3,505	25,057
2007-08	2,336	1,536	2,621	936	1,312	1,886	1,727	524	904	7,643	3,596	25,021
2008-09	2,274	1,567	2,533	930	1,289	1,771	1,634	529	884	7,692	3,570	24,673
2009-10	2,330	1,555	2,558	648	1,289	1,788	1,527	561	813	7,562	3,443	24,074
2010-11	2,413	1,606	2,657	645	1,296	1,825	1,586	526	927	7,661	3,512	24,654
2011-12	2,220	1,535	2,532	904	1,243	1,765	1,618	490	893	7,323	3,378	23,901
2012-13	2,343	1,568	2,672	954	1,348	1,923	1,539	510	947	7,456	3,399	24,658
2013-14	2,358	1,645	2,781	848	1,415	1,989	1,700	625	974	7,810	3,594	25,738
2014-15	2,382	1,575	2,608	858	1,323	1,905	1,554	538	935	7,529	3,530	24,737
2015-16	2,391	1,577	2,615	860	1,325	1,914	1,564	538	934	7,537	3,540	24,795
2016-17	2,399	1,580	2,621	863	1,327	1,925	1,568	540	939	7,544	3,550	24,856
2017-18	2,406	1,583	2,628	862	1,332	1,935	1,572	539	937	7,552	3,560	24,906
2018-19	2,413	1,587	2,636	863	1,338	1,947	1,576	540	937	7,559	3,570	24,966
2019-20	2,423	1,591	2,645	934	1,345	1,961	1,580	540	938	7,567	3,580	25,104
2020-21	2,433	1,596	2,654	937	1,355	1,972	1,583	542	941	7,574	3,590	25,177
2021-22	2,444	1,602	2,667	936	1,365	1,985	1,589	542	940	7,582	3,600	25,252
2022-23	2,455	1,608	2,679	936	1,377	2,000	1,597	542	940	7,590	3,610	25,334
2023-24	2,468	1,617	2,692	937	1,389	2,017	1,607	542	941	7,597	3,620	25,427
2024-25	2,484	1,628	2,709	939	1,402	2,037	1,618	543	942	7,605	3,630	25,537

Appendix D - Transmission System Security and Resource Adequacy Assessment

The analysis performed during the Reliability Needs Assessment requires the development of base cases for transmission security analysis and for resource adequacy analysis. The power flow system model is used for transmission security assessment and the development of the transfer limits to be implemented in the Multi-Area Reliability Simulation (MARS) model. A comprehensive assessment of the transmission system is conducted through a series of steady-state power flow, transient stability, and short circuit studies.

In general, the RNA analyses indicated that the bulk power transmission system can be secured under N-1 conditions, but that transfer limits for certain key interfaces must be reduced below their thermal limits, in order to respect voltage criteria. However, a reduction in transfer limits on a limiting interface can result in higher LOLE, and/or needs occurring earlier than they otherwise would. To quantify this potential impact, LOLE analysis was conducted for the RNA base case, a case modeling voltage limited interfaces using the higher thermal limits (NYCA Thermal), and also a case without any internal NYCA transmission limits (NYCA Free Flow). These cases were simulated to demonstrate the impact that transmission limits have on the LOLE results. The results from this analysis are reported in Table 4-7.

The MARS model was used to determine whether adequate resources would be available to meet the NYSRC and NPCC reliability criteria of one day in ten years (0.1 days/year). The results showed a deficiency in years 2019 – 2024 (See Section 4.2.3 of this report.) The MARS model was also used to evaluate selected scenarios (Section 4.3) and it was used to determine compensatory MW requirements for identified Reliability Needs (See Section 4.2.5).

D-1 2014 RNA Assumption Matrix

D-1.1 Assumption Matrix for Resource Adequacy Assessment

Parameter	2014 IRM Model Assumptions Recommended	Basis for IRM Recommendation	2014 RNA Model Change
Load Parameters			
Peak Load	October 1 , 2013 forecast: NYCA 33,655 MW, NYC 11,740 MW, LI 5,461 MW	Forecast based on examination of 2013 weather normalized peaks. Top three external Area peak days aligned with NYCA	2014 Gold Book, NYCA loads similar to Oct 2013 forecast, NYC and LI lower
Load Shape	Multiple Load Shapes Model using years 2002, 2006, and 2007	See white paper	Same, Multiple Load Shapes Model using years 2002, 2006, and 2007
Load Forecast Uncertainty	Zonal model updated to reflect current data	Based on collected data and input from LIPA, Con Ed, and NYISO. (See attachment A)	Same
Capacity Parameters			
Existing Generating Unit Capacities	2013 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2013 Gold Book publication	2014 Gold Book, capacity similar to 2013 Gold Book
Proposed New Non-Wind Units	76.9 MW of capacity was repowered or returned to service (see Attachment B)	Units built since the 2013 Gold Book and those non-renewable units with Interconnection Agreements signed by August 1.	Consistent with Inclusion Rules, capacity repowered or returned to service plus Taylor Biomass included in the base case
Retirement Units*	164 MW retirements reported, See Attachment B3	Policy 5 guidelines on retirement disposition in IRM studies	2014 Gold Book Section IV, not modeled in the base case
Mothball Units*			2014 Gold Book Section IV, Cayuga modeled 2015 and 2016 only. Not modeled in the base case: Dunkirk 1, 2, 3, and 4, 9/10/2012, TC Ravenswood GT 7, 3/13/2014, and Selkirk I & II, 9/1/2014
ICAP Ineligible Forced Outage Units			N/A
Forced Outage Units			Modeled in the base case with EFOR reflecting the outage
Forced and Partial Outage Rates	Five-year (2008-2012) GADS data for each unit represented. Those units with less than five years – use representative data. See attachments C and C1	T. Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2008-2012)	Update for most recent five year period, 2009-2013
Planned Outages	Based on schedules received by the NYSIO and adjusted for history	Updated schedules, currently, data from last year is being used	Same

Parameter	2014 IRM Model Assumptions Recommended	Basis for IRM Recommendation	2014 RNA Model Change
Summer Maintenance	Nominal 50 MW – divided equally between upstate and downstate	Review of most recent data	Same
Combustion Turbine Derates	Derates based on temperature correction curves provided	Operational history indicates the derates are in-line with manufacturer's curves	Same
Proposed New Wind Units	No new wind, See Attachment B1	Renewable units based on RPS agreements, interconnection Queue and ICS input	2014 Gold Book IV, no new wind units
Wind Resources	Wind Capacity – 1366.6 MW	Number decrease due to a (2013 IRM) forecast not participating in NY Capacity market (Marble River Wind).	2014 Gold Book Section III and IV
Wind Shape	Actual hourly plant output of the 2012 calendar year. Summer Peak Hour availability of 17%	Testing results and White Paper	Same
Solar Resources	Solar Capacity of 31.5 MW plus 12.5 MW of new units. See Attachment B-2	Based on collected hourly solar data, Summer Peak Hour capacity factor based on June 1 – Aug 31, hours HB14 – HB18	2014 Gold Book, as reflected in Load Forecast
Non-NYPA Hydro Resources	Derated by 45%	Review of unit production and hydrological conditions including recognized forecasts (i.e. NOAA)	Same
Capacity Purchases	Grandfathered amounts: PJM – 1080 MW, HQ – 1090 MW, All contracts model as equivalent contracts	Grandfathered Rights, ETCNL, and other FERC identified rights	Modeled same as in 2012 RNA
Capacity Sales	Long Term firm sales (279 MW)	These are long term federally monitored contracts	
UDRs	No new UDRs		Updated to most current UDRs
Topology Parameters			
Interface Limits	All changes reviewed and commented on by TPAS. See Attachment E.	Based on 2013 Operating Study, 2013 Operations Engineering Voltage Studies, 2013 Comprehensive Planning Process, and additional analysis including interregional planning initiatives	updated analysis extended for ten years
New Transmission	None Identified	Based on TO provided models and NYISO review	2014 Gold Book Section VII that are consistent with the inclusion rules Firm projects in-service within three years are modeled, such as TOTS (2016), Five Mile Road (2015), Mainesburg (2015), Farmers Valley (2016), etc.

Parameter	2014 IRM Model Assumptions Recommended	Basis for IRM Recommendation	2014 RNA Model Change
Cable Forced Outage Rates	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	Based on TO analysis	Same transition rate as provided by TO and held constant over ten years
Emergency Operating Procedure Parameters			
Special Case Resources	July 2014 – 1195 MW based on registrations and modeled as 758 MW of effective capacity. Monthly variation based on historical experience (no Limit on number of calls)	Those sold for the program discounted to historic availability. Summer values calculated from July 2013 registrations (see attachment F).	2014 Gold Book, registration ICAP is similar to IRM but UCAP is higher
EDRP Resources	July 2013 – 93.9 MW registered model as 12.8 MW in July and proportional to monthly peak load in other months. Limit to five calls per month	Those sold for the program discounted to historic availability. Summer values calculated from July 2013 registrations and forecast growth.	2014 Gold Book, registration ICAP and UCAP are both similar to IRM
Other EOPs	721 MW of non-SCR/non-EDRP resources See Attachment D	Based on TO information, measured data, and NYISO forecasts	Updated as available
External Control Areas Parameters			
PJM	Load and Capacity data provided by PJM/NPCC CP-8, and may be adjusted per NYSRC Policy 5		LOLE adjusted to between 0.1 and 0.15 for every year of ten year period
ISONE	Load and Capacity data provided by PJM/NPCC CP-8, and may be adjusted per NYSRC Policy 5		LOLE adjusted to between 0.1 and 0.15 for every year of ten year period
HQ	Load and Capacity data provided by PJM/NPCC CP-8, and may be adjusted per NYSRC Policy 5		LOLE adjusted to between 0.1 and 0.15 for every year of ten year period
IESO	Load and Capacity data provided by PJM/NPCC CP-8, and may be adjusted per NYSRC Policy 5		LOLE adjusted to between 0.1 and 0.15 for every year of ten year period
Reserve Sharing	All NPCC Control Areas and PJM interconnection indicate that they will share reserves equally among all members	Per NPCC CP-8 WG	Same
Miscellaneous			
MARS Model Version	Version 3.16.5	Per benchmark testing and ICS recommendation	Version 3.18
Environmental Initiatives	No estimated impacts based on review of existing rules and retirement trends	An analysis of generator plans to comply with new regulations in 2014	Updated to most recent NYSDEC BTA determination

*Treatment of retired or mothballed units for purposes of RNA modeling: Any generating units that, pursuant to the PSC Orders in Case 05-E-0889, have provided a notice of Retirement, Mothball, etc., by the study lock-down date, were assumed not to be available for the RNA study period.

D-1.2 Assumption Matrix for Transmission Security Assessment

Parameter	Modeling Assumptions	Source
Peak Load	NYCA baseline coincident summer peak forecast	2014 Gold Book
Load model	ConEd: voltage varying Rest of NYCA: constant power	2014 FERC 715 filing
System representation	Per updates received through Databank process (Subject to RNA base case inclusion rules)	NYISO RAD Manual, 2014 FERC 715 filing
Inter-area interchange schedules	Consistent with ERAG MMWG interchange schedule	2014 FERC 715 filing, MMWG
Inter-area controllable tie schedules	Consistent with applicable tariffs and known firm contracts or rights	2014 FERC 715 filing
In-city series reactors	Consistent with ConEdison operating protocol (All series reactors in-service for summer)	2014 FERC 715 filing, ConEd protocol
SVCs, FACTS	Set at zero pre-contingency; allowed to adjust post-contingency	NYISO T&D Manual
Transformer & PAR taps	Taps allowed to adjust pre-contingency; fixed post-contingency	2014 FERC 715 filing
Switched shunts	Allowed to adjust pre-contingency; fixed post-contingency	2014 FERC 715 filing
Fault current analysis settings	Per Fault Current Assessment Guideline	NYISO Fault Current Assessment Guideline
Model Version	Power flow: PSS/E v32.2.1, PSS/MUST v11.0, TARA v735 Dynamics: PSS/E v32.2.1 Short Circuit: ASPEN v12.2	

D-2 RNA Power Flow Base Case Development and Thermal Transfer Limit Results

D- 2.1 Development of RNA Power Flow Base Cases

The base cases used in analyzing the performance of the transmission system were developed from the 2014 FERC 715 filing power flow case library. The load representation in the power flow model is the summer peak load forecast reported in the 2014 Gold Book Table 1-2a baseline forecast of coincident peak demand. The system representation for the NPCC Areas in the base cases is from the 2013 Base Case Development (BCD) libraries compiled by the NPCC SS-37 Base Case Development working group. The PJM system representation was derived from the PJM Regional Transmission Expansion Plan (RTEP) planning process models. The remaining models are from the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) 2013 power flow model library.

The 2014 RNA base case model of the New York system representation includes the following new and proposed facilities:

1. TO LTPs for non-bulk transmission facilities and NYPA transmission plans for non-bulk power facilities which are reported to the NYISO as firm transmission plans will be included,
2. TO bulk power system projects not in-service or under construction will be included if:
   a. the project is the regulated solution triggered in a prior year, or
   b. the project is required in connection with any projects and plans that are included in the Study Period base case, or
   c. the project is part of a TO LTP or the NYPA transmission plan, and reported to the NYISO as a firm transmission plan(s), and is expected to be in service within 3 years, and has an approved SRIS or an approved SIS (as applicable), and has received NYPSC certification (or other required regulatory approvals and reviews).
3. Other projects that are in-service or under construction will be included,
4. Other projects not already in-service or under construction will be included and modeled at the contracted-for capacity if they have:
   a. an approved SRIS or an approved SIS (as applicable), and
   b. a NYPSC certificate, or other required regulatory approvals and complete review under the State Environmental Quality Review Act ("SEQRA") where the NYPSC siting process is not applicable, and
   c. an executed contract with a credit worthy entity for at least half of the project capacity.

The RNA base case does not include all projects currently listed on the NYISO's interconnection queue or those shown in the 2014 Gold Book. It includes only those which meet the screening requirements for inclusion. The firm transmission plans included in 2014 RNA base case are included in Table D-1 below.

Table D-1: Firm Transmission Plans included in 2014 RNA Base Case

Transmission Owner	Terminals		Line Length in Miles	Expected In-Service Date/Yr Prior to	Expected In-Service Date/Yr Year	Nominal Voltage in kV Operating	Nominal Voltage in kV Design	# of ckts	Thermal Ratings Summer	Thermal Ratings Winter	Project Description / Conductor Size	Class Year / Type of Construction
CHGE	North Catskill	Feura Bush	Series Reactor	S	2014	115	115	1	1280	1560	Reactor impedance increase from 12% to 16%	-
CHGE	Pleasant Valley	Todd Hill	5.53	W	2015	115	115	1	1280	1563	Rebuild line with 1033 ACSR	OH
CHGE	Todd Hill	Fishkill Plains	5.23	W	2015	115	115	1	1280	1563	Rebuild line with 1033 ACSR	OH
CHGE	Hurley Ave	Saugerties	11.40	S	2020	115	115	1	1114	1359	1-795 ACSR	OH
CHGE	Saugerties	North Catskill	12.46	S	2020	115	115	1	1114	1359	1-795 ACSR	OH
CHGE	St. Pool	High Falls	5.61	S	2020	115	115	1	1114	1359	1-795 ACSR	OH
CHGE	High Falls	Kerhonkson	10.03	S	2020	115	115	1	1114	1359	1-795 ACSR	OH
CHGE	Kerhonkson	Honk Falls	4.97	S	2020	115	115	2	1114	1359	1-795 ACSR	OH
CHGE	Modena	Galeville	4.62	S	2020	115	115	1	1114	1359	1-795 ACSR	OH
CHGE	Galeville	Kerhonkson	8.96	S	2020	115	115	1	1114	1359	1-795 ACSR	OH
ConEd	Dunwoodie South	Dunwoodie South	Phase shifter	S	2014	138	138	2	Nominal 132 MVA		PAR Retirement	-
ConEd	Dunwoodie South	Dunwoodie South	Phase shifter	S	2014	138	138	1	Nominal 300 MVA		PAR Replacement	-
ConEd	Goethals	Goethals	Reconfiguration	S	2014	345	345		N/A	N/A	Reconfiguration	-
ConEd	Rock Tavern	Sugarloaf	13.70	S	2016	345	345	1	1811 MVA	1918 MVA	2-1590 ACSR	OH
ConEd	Goethals	Gowanus	12.95	S	2016	345	345	2	632 MVA	679 MVA	Additional Cooling	UG
ConEd	Gowanus	Farragut	4.05	S	2016	345	345	2	800 MVA	844 MVA	Additional Cooling	UG
ConEd	Goethals	Linden Co-Gen	-1.50	S	2016	345	345	1	2504	2504	Feeder Seperation	UG
ConEd	Goethals	Linden Co-Gen	1.50	S	2016	345	345	1	1252	1252	Feeder Seperation	UG
ConEd	Goethals	Linden Co-Gen	1.50	S	2016	345	345	1	1252	1252	Feeder Seperation	UG
ConEd	Greenwood	Greenwood	Reconfiguration	S	2018	138	138		N/A	N/A	Reconfiguration	-
LIPA	Holtsville DRSS	West Bus	N/A	S	2014	138	138	-	150 MVAR	150 MVAR	Dynamic Reactive Support System (DRSS)	
LIPA	Randall Ave	Wildwood	N/A	S	2014	138	138	-	150 MVAR	150 MVAR	Dynamic Reactive Support System (DRSS)	
NGRID	Dunkirk	Dunkirk	Cap Bank	W	2014	115	115	1	67 MVAR	67 MVAR	Capacitor Bank 2 - 33.3 MVAR	-
NGRID	Rome	Rome	-	W	2014	115	115	-	N/A	N/A	Station Rebuild	-
NGRID	Porter	Porter	-	W	2014	115	115	-	N/A	N/A	Rebuild 115kV Station	-
NGRID	Homer City	Stolle Road	-204.11	S	2015	345	345	1	1013	1200	New Five Mile substation	OH
NGRID	Homer City	Five Mile Rd (New Station)	151.11	S	2015	345	345	1	1013	1200	New Five Mile substation	OH
NGRID	Five Mile Rd (New Station)	Stolle Road	53.00	S	2015	345	345	1	1013	1200	New Five Mile substation	OH
NGRID	Gardenville	Homer Hill	-65.69	S	2015	115	115	2	584	708	New Five Mile substation	OH
NGRID	Gardenville	Five Mile Rd (New Station)	58.30	S	2015	115	115	2	129MVA	156MVA	New Five Mile substation	OH
NGRID	Five Mile Rd (New Station)	Five Mile Rd (New Station)	xfmr	S	2015	345/115	345/115	-	478MVA	590MVA	New Five Mile substation	-
NGRID	Five Mile Rd (New Station)	Homer Hill	8.00	S	2015	115	115	2	129MVA	156MVA	New Five Mile substation	OH
NGRID	Clay	Clay	xfmr	S	2015	345/115	345/115	1	478MVA	590MVA	Replace Transformer	-
NGRID	Rotterdam	Bear Swamp	-43.64	S	2015	230	230	1	1105	1284	795 ACSR	OH
NGRID	Rotterdam	Eastover Road (New Station)	23.20	S	2015	230	230	1	1114	1284	Rotterdam-Bear Swamp #E205 Loop (0.8 miles new)	OH
NGRID	Eastover Road (New Station)	Bear Swamp	21.88	S	2015	230	230	1	1105	1347	Rotterdam-Bear Swamp #E205 Loop (0.8 miles new)	OH

Transmission Owner	Terminals		Line Length in Miles	Expected In-Service Date/Yr Prior to	Year	Nominal Voltage in kV Operating	Design	# of ckts	Thermal Ratings Summer	Winter	Project Description / Conductor Size	Class Year / Type of Construction
NGRID	Eastover Road (New Station)	Eastover Road (New Station)	xfmr	S	2015	230/115	230/115	1	345MVA	406MVA	Transformer	-
NGRID	Luther Forest	North Troy	-18.30	S	2015	115	115	1	937	1141	1033.5 ACSR	
NGRID	Luther Forest	Eastover Road (New Station)	17.50	S	2015	115	115	1	937	1141	Luther Forest-North Troy Loop (0.9 miles new)	OH
NGRID	Eastover Road (New Station)	North Troy	2.60	S	2015	115	115	1	937	1141	Luther Forest-North Troy Loop (0.9 miles new)	OH
NGRID	Battenkill	North Troy	-22.39	S	2015	115	115	1	916	1118	605 ACSR	
NGRID	Battenkill	Eastover Road (New Station)	21.59	S	2015	115	115	1	937	1141	Battenkill-North Troy Loop (0.9 miles new)	
NGRID	Eastover Road (New Station)	North Troy	2.60	S	2015	115	115	1	916	1118	Battenkill-North Troy Loop (0.9 miles new)	
NGRID/NYSE	Homer City	Five Mile Rd (New Station)	-151.11	S	2016	345	345	1	1013	1200	New Five Mile substation	OH
NGRID/NYSE	Homer City	Farmers Valley	120.00	S	2016	345	345	1	1013	1200	New Farmer Valley substation	OH
NGRID/NYSE	Farmers Valley	Five Mile Rd (New Station)	31.00	S	2016	345	345	1	1013	1200	New Farmer Valley substation	OH
NGRID	Clay	Dewitt	10.24	W	2017	115	115	1	193MVA	245MVA	Reconductor 4/0 CU to 795ACSR	OH
NGRID	Clay	Teall	12.75	W	2017	115	115	1	220 MVA	239MVA	Reconductor 4/0 CU to 795ACSR	OH
NYPA	Moses	Willis	-37.11	S	2014	230	230	2	876	1121	795 ACSR	OH
NYPA	Moses	Willis	37.11	S	2014	230	230	1	876	1121	795 ACSR	OH
NYPA	Moses	Willis	37.11	S	2014	230	230	1	876	1121	795 ACSR	OH
NYPA	Moses	Moses	Cap Bank	W	2014	115	115	1	100 MVAR	100 MVAR	Cap Bank Installation to Replace Moses Synchronous Condensers	-
NYPA	Moses	Moses	Cap Bank	W	2015	115	115	1	100 MVAR	100 MVAR	Cap Bank Installation to Replace Moses Synchronous Condensers	-
NYPA	Marcy	Coopers Corners	Series Comp	S	2016	345	345	1	1776 MVA	1793 MVA	Installation of Series Compensation on UCC2-41	-
NYPA	Edic	Fraser	Series Comp	S	2016	345	345	1	1793 MVA	1793 MVA	Installation of Series Compensation on EF24-40	-
NYPA	Fraser	Coopers Corners	Series Comp	S	2016	345	345	1	1494 MVA	1793 MVA	Installation of Series Compensation on FCC33	-
NYPA	Niagara	Rochester	-70.20	W	2016	345	345	1	2177	2662	2-795 ACSR	OH
NYPA	Niagara	Station 255 (New Station)	66.40	W	2016	345	345	1	2177	2662	2-795 ACSR	OH
NYPA	Station 255 (New Station)	Rochester	3.80	W	2016	345	345	1	2177	2662	2-795 ACSR	OH
NYPA	Dysinger Tap	Rochester	-44.00	W	2016	345	345	1	2177	2662	2-795 ACSR	OH
NYPA	Dysinger Tap	Station 255 (New Station)	40.20	W	2016	345	345	1	2177	2662	2-795 ACSR	OH
NYPA	Station 255 (New Station)	Rochester	3.80	W	2016	345	345	1	2177	2662	2-795 ACSR	OH
NYSEG	Meyer	Meyer	Cap Bank	S	2014	115	115	1	18 MVAR	18 MVAR	Capacitor Bank Installation	-
NYSEG	Wood Street	Katonah	11.70	W	2014	115	115	1	775	945	477 ACSR	OH
NYSEG	Ashley Road	Ashley Road	Cap Bank	W	2014	115	115	1	150 MVAR	150 MVAR	Capacitor Bank (DOE)	-
NYSEG	Big Tree	Big Tree	Cap Bank	W	2014	115	115	1	50 MVAR	50 MVAR	Capacitor Bank (DOE)	-
NYSEG	Coopers Corners	Coopers Corners	Shunt Reactor	W	2014	345	345	1	200 MVAR	200 MVAR	Shunt Reactor Installation	-
NYSEG	Watercure Road	Watercure Road	xfmr	W	2015	345/230	345/230	1	426 MVA	494 MVA	Transformer	-
NYSEG	Goudey	AES Westover	reconfig	W	2014	115	115	-	N/A	N/A	substation separation	-
NYSEG	Jennison	AES Oneonta	reconfig	W	2014	115	115	-	N/A	N/A	substation separation	-
NYSEG	Homer City	Watercure Road	-177.00	S	2015	345	345	1	1549	1552	2156 ACR	OH
NYSEG	Watercure Road	Mainesburg	26.00	S	2015	345	345	1	1549	1552	2156 ACR	OH
NYSEG	Mainesburg	Homer City	151.00	S	2015	345	345	1	1549	1552	2156 ACR	OH
NYSEG	Wood Street	Carmel	1.34	W	2015	115	115	1	775	945	477 ACSR	OH

Transmission Owner	Terminals		Line Length in Miles	Expected In-Service Date/Yr Prior to	Expected In-Service Date/Yr Year	Nominal Voltage in kV Operating	Nominal Voltage in kV Design	# of ckts	Thermal Ratings Summer	Thermal Ratings Winter	Project Description / Conductor Size	Class Year / Type of Construction
NYSEG	Carmel	Katonah	13.04	S	2016	115	115	1	1079	1079	convert 46kV to 115kV	OH
NYSEG	Fraser	Coopers Corners	21.80	S	2016	345	345	1	2500	3000	ACCR 1742-T9 Reconductor	OH
NYSEG	Wood Street	Wood Street	xfmr	S	2016	345/115	345/115	1	280 MVA	300 MVA	Transformer	-
NYSEG	Elbridge	State Street	14.50	W	2016	115	115	1	250 MVA	305 MVA	1033 ACSR	OH
NYSEG	Gardenville	Gardenville	xfmr	S	2017	230/115	230/115	1	200 MVA	225 MVA	Transformer	-
NYSEG	Klinekill Tap	Klinekill	<10	W	2017	115	115	1	>=124 MVA	>=150 MVA	477 ACSR	OH
NYSEG	Stephentown	Stephentown	xfmr	W	2017	115/34.5	115/34.5	1	37 MVA	44MVA	Transformer	-
NYSEG	Colliers	Colliers	xfmr	W	2019	115/46	115/46	1	42 MVA	55 MVA	Transformer	-
NYSEG	Colliers	Colliers	xfmr	W	2019	115/46	115/46	1	63 MVA	75 MVA	Transformer	-
NYSEG	Carmel	Carmel	xfmr	W	2019	115/46	115/46	1	80 MVA	96MVA	Transformer	-
O & R	Ramapo	Sugarloaf	16.00	S	2014	138	345	1	1089	1298	2-1590 ACSR	OH
O & R	New Hempstead	-	Cap Bank	S	2014	138	138	1	32 MVAR	32 MVAR	Capacitor bank	-
O & R	Hartley	-	Cap Bank	S	2014	69	69	1	32 MVAR	32 MVAR	Capacitor bank	-
O & R	Summit (RECO)	-	Cap Bank	W	2015	69	69	1	32 MVAR	32 MVAR	Capacitor bank	-
O & R	Ramapo	Sugarloaf	16.00	S	2016	345	345	1	3030	3210	2-1590 ACSR	OH
O & R	Sugarloaf	Sugarloaf	xfmr	S	2016	345/138	345/138	1	400 MVA	400 MVA	Transformer	OH
O & R	Little Tor	-	Cap Bank	S	2016	138	138	1	32 MVAR	32 MVAR	Capacitor bank	-
O & R	O&R's Line 26	Sterling Forest	xfmr	S	2016	138/69	138/69	1	175 MVA	175 MVA	Transformer	
O & R	Burns	Corporate Drive	5.00	S	2016	138	138	1	1980	2120	1272 ACSS	OH
O & R	Harings Corner (RECO)	Tappan (NY)	-	S	2015	69	69	1	1096	1314	Three-way switch station	OH
O & R	West Nyack (NY)	Harings Corner (RECO)	7.00	W	2019	69	138	1	1604	1723	795 ACSS	OH
O & R	Ramapo	Sugarloaf	17.00	W	2020	138	138	1	1980	2120	1272 ACSS	OH
O & R	Montvale (RECO)	-	Cap Bank	S	2021	69	69	1	32 MVAR	32 MVAR	Capacitor bank	-
RGE	Station 69	Station 69	Cap Bank	S	2014	115	115	1	20 MVAR	20 MVAR	Capacitor Bank (DOE)	
RGE	Station 67	Station 418	3.5	W	2014	115	115	1	1255	1255	New 115kV Line	OH
RGE	Station 251	Station 251	xfmr	W	2014	115/34.5	115/34.5	2	30 MVA	33.8 MVA	Transformer	
RGE	Mortimer	Station 251	1	W	2014	115	115	2	1396	1707	New 115kV Line	OH
RGE	Station 251	Station 33	0.98	W	2014	115	115	2	1396	1707	New 115kV Line	OH
RGE	Station 23	Station 23	xfmr	S	2015	115/34.5	115/34.5	2	75 MVA	84 MVA	Transformer	
RGE	Station 23	Station 23	xfmr	S	2015	15/11.5/11	5/11.5/11	2	75 MVA	84 MVA	Transformer	
RGE	Station 42	Station 23	Phase Shifter	S	2015	115	115	1	253 MVA	285 MVA	Phase Shifter	
RGE	Station 168	Station 168	xfmr	S	2015	115/34.5	115/34.5	1	100 MVA	112 MVA	Transformer	
RGE	Station 262	Station 262	xfmr	S	2015	115/34.5	115/34.5	1	56 MVA	63 MVA	Transformer	
RGE	Station 33	Station 262	2.97	W	2015	115	115	1	2008	2409	Underground Cable	UG
RGE	Station 262	Station 23	1.46	W	2015	115	115	1	2008	2409	Underground Cable	UG
RGE	Station 255 (New Station)	Rochester	3.80	W	2016	345	345	1	2177	2662	2-795 ACSR	OH
RGE	Station 255 (New Station)	Station 255 (New Station)	xfmr	W	2016	345/115	345/115	2	400 MVA	450 MVA	Transformer	
RGE	Station 255 (New Station)	Station 418	9.60	W	2016	115	115	1	1506	1807	New 115kV Line	OH
RGE	Station 255 (New Station)	Station 23	11.10	W	2016	115	115	1	1506	1807	New 115kV Line	OH+UG

D-2.2 Emergency Thermal Transfer Limit Analysis

The NYISO performed analyses of the RNA base case to determine emergency thermal transfer limits for the key interfaces to be used in the MARS resource adequacy analysis. Table D-1 reports the emergency thermal transfer limits for the RNA base system conditions:

Table D-1: Emergency Thermal Transfer Limits

Interface	2015		2016		2017		2018		2019	
Dysinger East	2200	1	2150	1	2100	1	2075	1	2050	1
Volney East	5650	2	5650	2	5650	2	5650	2	5650	2
Moses South	2650	3	2650	3	2650	3	2650	3	2650	3
Central East MARS	4025	4	4500	5	4500	5	4500	5	4500	5
F to G	3475	6	3475	6	3475	6	3475	6	3475	6
UPNY-SENY MARS	5150	6	5600	6	5600	6	5600	6	5600	6
I to J (Dunwoodie South MARS)	4400	7	4400	7	4400	7	4400	7	4400	7
I to K (Y49/Y50)	1290	8	1290	8	1290	8	1290	8	1290	8

	Limiting Facility	Rating	Contingency
1	Huntley-Gardenville 230 kV (80)	755	Huntley-Gardenville 230 kV (79)
2	Oakdale-Fraser 345kV	1380	Edic-Fraser 345kV
3	Marcy 765/345 T2 transformer	1971	Marcy 765/345 T1 transformer
4	New Scotland-Leeds 345kV	1724	New Scotland-Leeds 345kV
5	Porter-Rotterdam 230kV	560	Porter-Rotterdam 230kV
6	Leeds-Pleasant Valley 345 kV	1725	Athens-Pleasant Valley 345 kV
7	Mott Haven-Rainey 345 kV	786	Pre-disturbance
8	Dunwoodie-Shore Rd 345 kV	653	Pre-disturbance

Table D-1a: Dynamic Limit Tables

Year	Interface	Oswego Complex Units*				
		All available	any 1 out	any 2 out	any 3 out	any 4 out
2015	Central East MARS	3250	3200	3140	3035	2920
	CE Group	4800	4725	4640	4485	4310
2016 - 2024	Central East MARS	3100	3050	2990	2885	2770
	CE Group	5000	4925	4840	4685	4510

* 9 Mile Point 1, 9 Mile Point 2, Fitzpatrick, Oswego 5, Oswego 6, Independence (Modeled as one unit in MARS)

Year	Interface	Huntley / Dunkirk Units				
		All available	any 1 out	any 2 out	any 3 out	4 out
2015	Dysinger East	2950	2650	2200	1575	950
	Zone A Group	3450	2850	2300	1550	775
2016	Dysinger East	2900	2600	2150	1525	900
	Zone A Group	3425	2825	2275	1525	750
2017	Dysinger East	2850	2550	2100	1475	850
	Zone A Group	3400	2800	2250	1500	725
2018	Dysinger East	2825	2525	2075	1450	825
	Zone A Group	3375	2775	2225	1475	700
2019	Dysinger East	2800	2500	2050	1425	800
	Zone A Group	3350	2750	2200	1450	675

* Huntley 67, Huntley 68, Dunkirk 3, Dunkirk 4

Year	Interface	Barrett Steam units (1 and 2)		
		Both available	Any 1 out	Both out
2015-2024	LI Sum	297	260	144
	CE-LIPA (towards Zone J)	510	403	283

Year	Interface	Staten Island Units*			
		All available	AK 3 on, and any one of AK 2, Linden Cogen 1 or Linden Cogen 2 out	AK3 out	Any 2 (or more) out
2015	Dummy Zone J3 to J	200	500	700	815

Year	Interface	Staten Island Units*	
		All available	Any out
2016-2024	Dummy Zone J3 to J	600	815

* Arthur Kill 2, Arthur Kill 3, Linden Cogen (Modeled as 2 units in MARS)

Year	Interface	PSEG units*			
		All available	any 1 out	Any 2 out	All out
2015-2024	Dummy Zone J2 to J	1000	600	500	400
	PJM East to Dummy Zone J2	1000	600	500	400

* Hudson 2, Bergen 2 CC, Linden 2 CC (PJM)

Year	Interface	Northport Units	
		All available	Any out
2015-2024	Norwalk CT to K (NNC)	388	428

D-3 2014 RNA MARS Model Base Case Development

The system representation for PJM, Ontario, New England, and Hydro Quebec modeled in the 2014 RNA base case was developed from the NPCC CP-8 2012 Summer Assessment. In order to avoid overdependence on emergency assistance from the external areas, the emergency operating procedure data was removed from the model for each External Area. In addition, the capacity of the external areas was further modified such that the LOLE value of each Area was a minimum value of 0.10 and capped at a value of 0.15 through the year 2024. The external area model was then frozen for the remaining study years (2015 – 2024). Because the load forecast in the NYCA continues to increase for the years 2015 – 2024, the LOLE for each of the external areas can experience increases despite the freeze of external loads and capacity.

The topology used in the MARS model is represented in Figures D-1 and D-2 for the year 2015, and Figures D-3 and D-4 for the year 2016. The internal transfer limits modeled are the summer emergency ratings derived from the RNA Power Flow cases discussed above. The external transfer limits are developed from the NPCC CP-8 Summer Assessment MARS database with changes based upon the RNA base case assumptions.

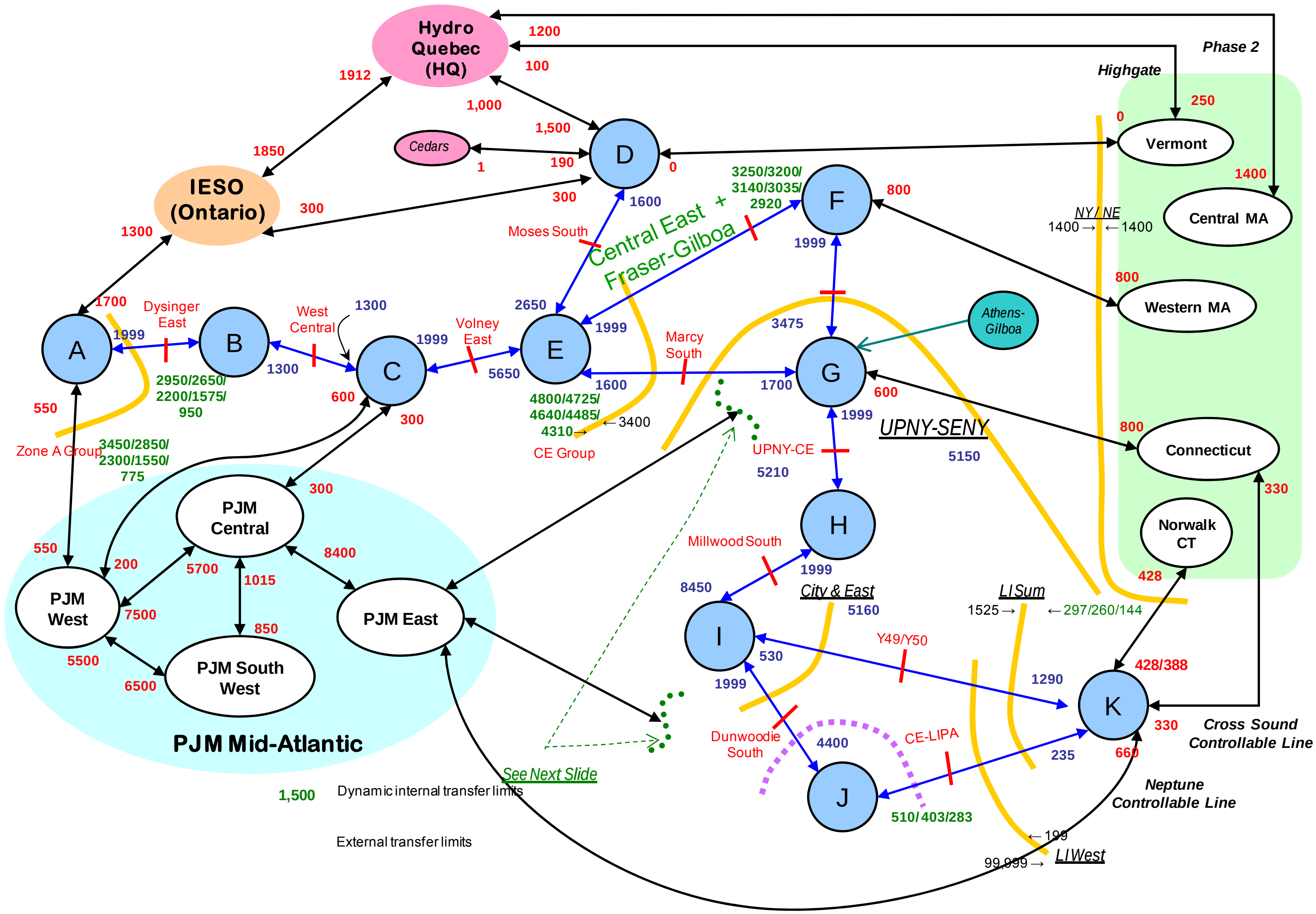
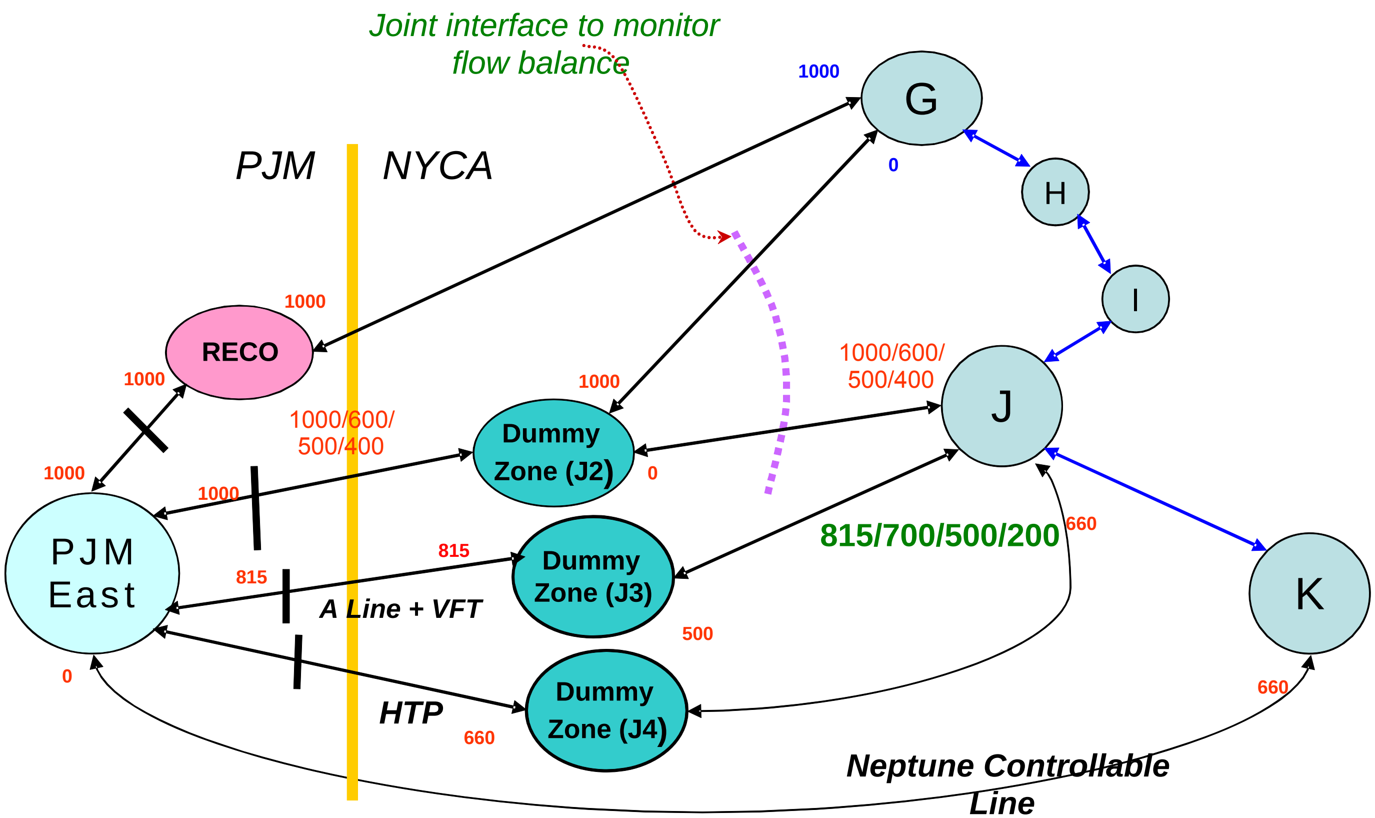


Figure D-1: MARS Topology for Year 2015



<u>*(PJM East to RECO) +(PJM East to J2) + (PJM East to J3) + (PJM East to J4) = 3075 MW*</u>

Figure D-2: PJM-SENY MARS Topology for Year 2015

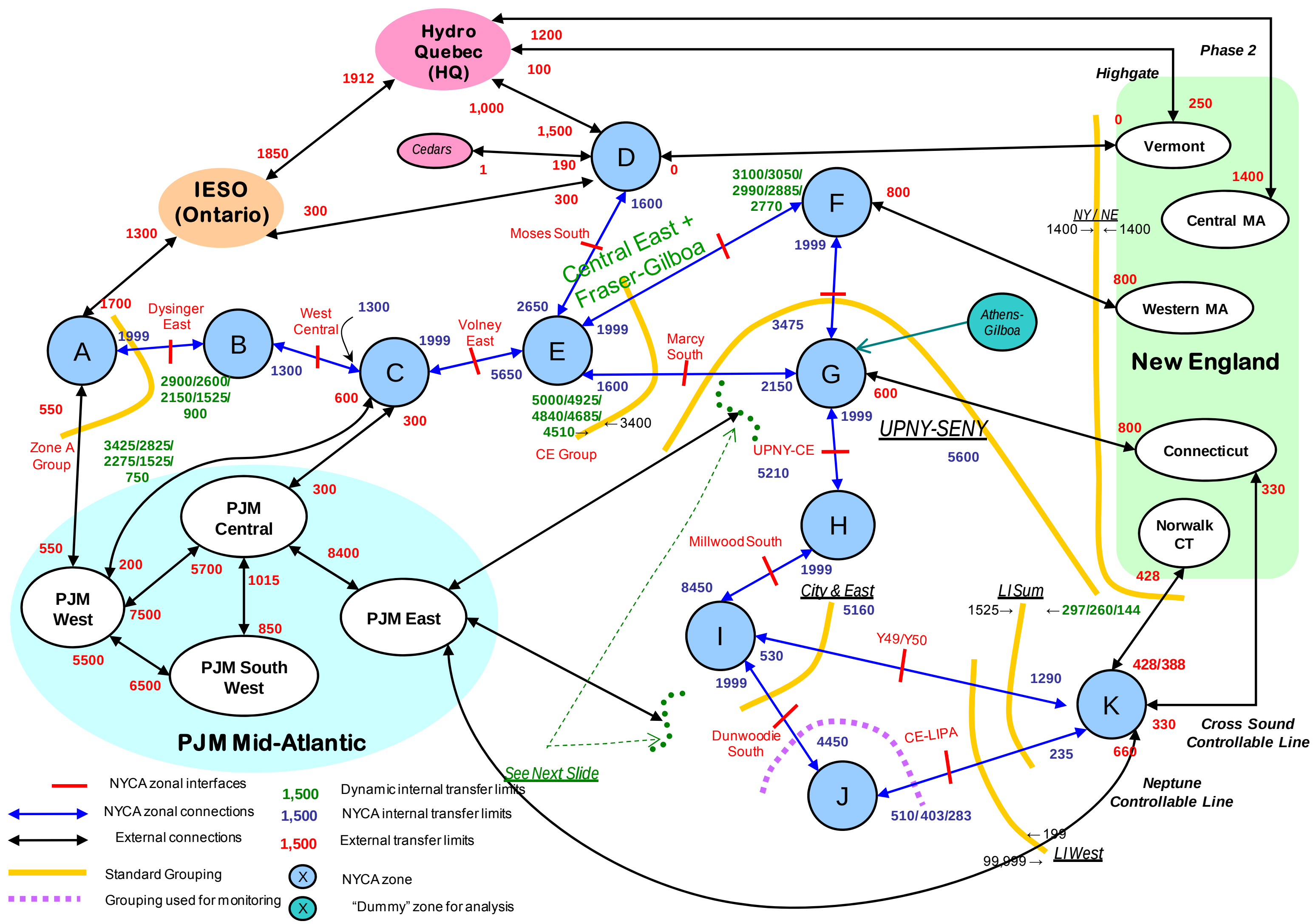


Figure D-3: MARS Topology for Year 2016

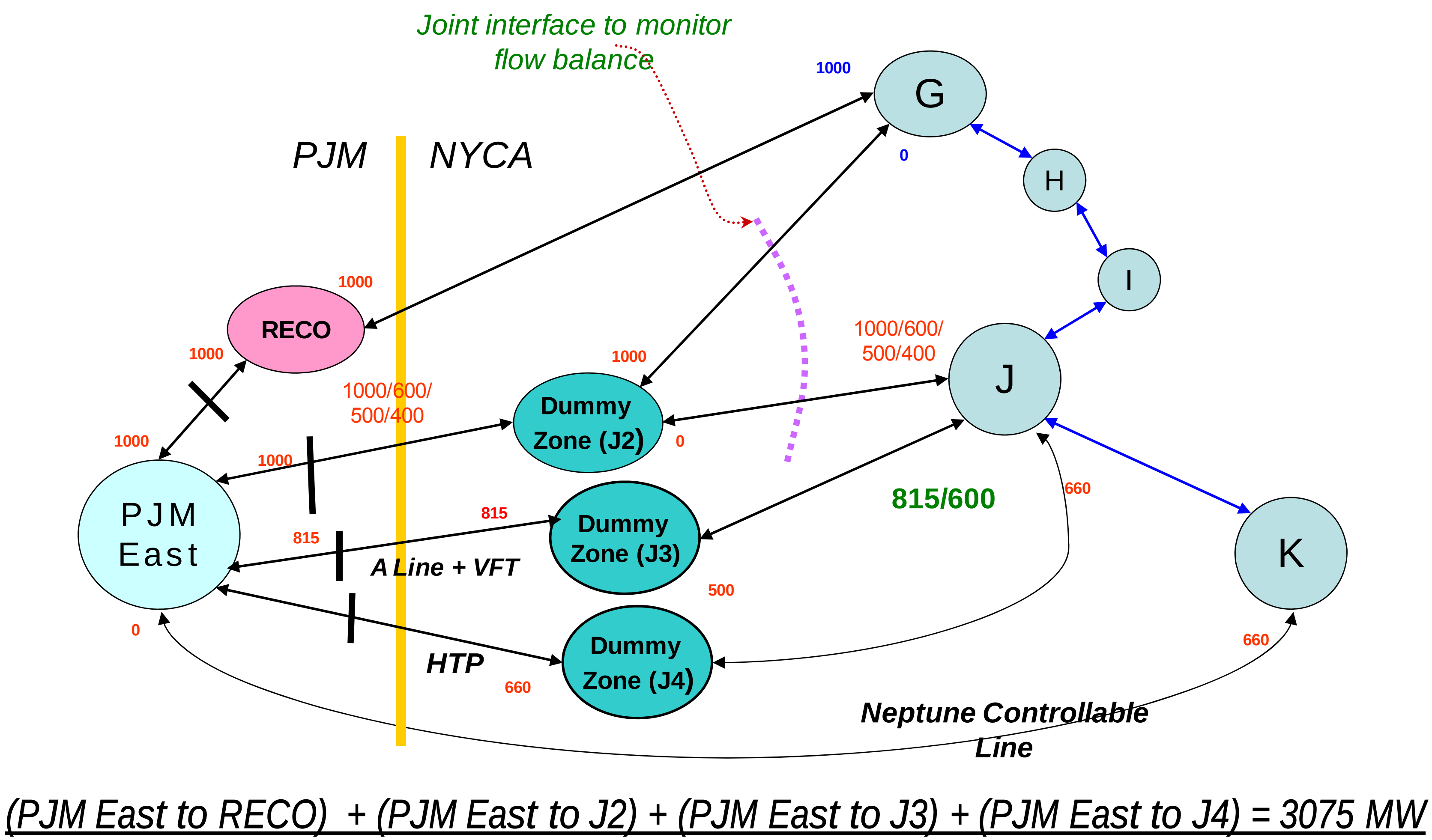


Figure D-4: PJM-SENY MARS Topology for Year 2016

D-4 Short Circuit Assessment

Table D-2 provides the results of NYISO's short circuit screening test. Individual breaker assessment (IBA) is required for any breakers whose rating is exceeded by the maximum fault current. Either NYISO or the Transmission Owner may complete the IBA.

Table D-2: 2014 RNA Fault Current Analysis Summary Table

Substation Name	Nominal kV	Lowest Rated Circuit Breaker	TO number	2014 RNA Maximum Bus Fault	IBA Required	Breaker(s) Overdutied
Academy	345	63	2	32.6	N	N
Adirondack	230	25	5	9.6	N	N
AES Somerset	345	32	4	17.9	N	N
Alps	345	40	5	17.5	N	N
Astoria East	138	63	2	52.2	N	N
Astoria West	138	45	2	46.6	Y	N
Astoria Annex	345	63	2	47.4	N	N
Athens	345	50.2	5	33.9	N	N
Barrett	138	57.8	3	49.3	N	N
Bowline 2	345	40	6	27.6	N	N
Bowline 1	345	40	6	27.8	N	N
Brookhaven	138	37	3	27.1	N	N
Buchanan N.	345	63	2	29.7	N	N
Buchanan S.	345	40	2	39	N	N
Buchanan	138	40	2	15.9	N	N
Stony Creek	230	40	4	9.5	N	N
Canandaiagua	230	40	4	6.5	N	N
Chases Lake	230	40	5	9.1	N	N
Clarks Corners	345	40	4	11.7	N	N
Clay	115	46.7	5	36	N	N
Clay	345	49	5	32.8	N	N
Coopers Corners	345	32	4	17.2	N	N
Corona	138	63	2	52.5	N	N
Dewitt	345	40	5	18.9	N	N
Duley	230	40	7	7.4	N	N
Dunwoodie No.	138	40	2	34.5	N	N
Dunwoodie So.	138	40	2	30.7	N	N
Dunkirk	230	29	5	9.9	N	N
Dunwoodie	345	63	2	50.6	N	N
East 13th	138	63	2	48	N	N
East 179th	138	63	2	48.6	N	N

Substation Name	Nominal kV	Lowest Rated Circuit Breaker	TO number	2014 RNA Maximum Bus Fault	IBA Required	Breaker(s) Overdutied
East 75 ST	138	63	2	9.1	N	N
East Fishkill	345	50	2	38.9	N	N
E River	69	50	2	50	Y	N
Eastview	138	63	2	36.9	N	N
Edic	345	41.6	5	32.7	N	N
East Garden City	345	63	7	25.4	N	N
East Garden City	138	80	3	70.5	N	N
Elbridge	345	40	5	16	N	N
ELWOOD 1	138	56.6	3	38.5	N	N
ELWOOD 2	138	56.6	3	38.2	N	N
Farragut	345	63	2	61.8	N	N
Fitzpatrick	345	37	7	41.4	Y	N
Fox Hills	138	40	2	33.7	N	N
Fresh Kills	345	63	2	36.1	N	N
Fresh Kills	138	40	2	27.1	N	N
Fraser	345	29.6	4	19.2	N	N
Freeport	138	63	3	35.9	N	N
Gardenville	230	31.2	5	21.6	N	N
Gilboa	345	40	7	25	N	N
Goethals	345	63	2	29.5	N	N
Gowanus	345	63	2	28.3	N	N
Greenlawn	138	63	3	29.2	N	N
Greenwood	138	63	2	49.8	N	N
Haupague	138	63	3	22.5	N	N
Hellgate	138	63	2	42.8	N	N
High Sheldon	230	40	4	10.5	N	N
Hillside	230	28.6	4	13.2	N	N
Holbrook	138	52.2	3	49	N	N
Holtsgt	138	63	3	45.4	N	N
Hudson E	138	63	2	39.4	N	N
Huntley	230	30.5	5	26.6	N	N
Hurley Avenue	345	30.4	9	17.1	N	N
Independence	345	44.5	5	38.4	N	N
Jamaica	138	63	2	49.2	N	N
Ladentown	345	63	6	40.4	N	N
Lafayette	345	40	5	17.8	N	N
Leeds	345	37.7	5	34.5	N	N
Lake Success	138	57.8	3	38.7	N	N
Marcy	345	63	7	31.9	N	N
Marcy	765	63	7	9.8	N	N

Substation Name	Nominal kV	Lowest Rated Circuit Breaker	TO number	2014 RNA Maximum Bus Fault	IBA Required	Breaker(s) Overdutied
Massena	765	63	7	7.9	N	N
Meyer	230	28.6	4	7.1	N	N
Middletown Tap	345	63	7	18.6	N	N
Millwood	138	40	2	19.4	N	N
Millwood	345	63	2	44.8	N	N
Mott Haven	345	63	2	51.3	N	N
Newbridge Road	138	80	3	69.4	N	N
Newbridge Road	345	40	3	8.6	N	N
Niagara	345	63	7	33.8	N	N
Niagara E	230	63	7	56.8	N	N
Niagara W	230	63	7	56.8	N	N
Nine Mile Point 1	345	50	5	43.4	N	N
Northport	138	56.2	3	60.8	Y	N
New Scotland 77B	345	41.5	5	31	N	N
New Scotland 99B	345	32.9	5	31	N	N
Oakdale	345	29.6	4	12.8	N	N
Oakwood	138	57.8	3	28.3	N	N
Oswego	345	44.3	5	32.4	N	N
Packard	230	48.6	5	43.7	N	N
Patnode	230	63	7	9.4	N	N
Pilgrim	138	63	3	60.2	N	N
Pleasant Valley	345	63	2	40.4	N	N
Porter	115	41.1	5	41.3	Y	Y
Porter	230	18.4	5	19.6	Y	Y
Port Jefferson	138	63	3	32.7	N	N
Pleasantville	345	63	2	22	N	N
Queensbridge	138	63	2	44.8	N	N
Rainey	345	63	2	58.4	N	N
Ramapo	345	63	2	45	N	N
Reynolds Road	345	40	5	14.8	N	N
Riverhead	138	63	3	19.1	N	N
Robinson Road	230	34.4	4	14.4	N	N
Rock Tavern	345	57.9	9	31.4	N	N
Roseton	345	63	9	35.4	N	N
Rotterdam 66H	230	39.4	5	13.3	N	N
Rotterdam 77H	230	23.6	5	13.2	N	N
Rotterdam 99H	230	23.4	5	13.3	N	N
Ruland	138	63	3	45.9	N	N
Ryan	230	63	7	10.6	N	N
South Ripley	230	40	5	9.6	N	N

Substation Name	Nominal kV	Lowest Rated Circuit Breaker	TO number	2014 RNA Maximum Bus Fault	IBA Required	Breaker(s) Overdutied
South Mahwah-A	345	40	6	35	N	N
South Mahwah- B	345	40	6	34.7	N	N
Station 80	345	32	8	17.7	N	N
Station 122	345	32	8	16.7	N	N
Springbrook TR N7	138	63	2	26.9	N	N
Springbrook TR S6	138	63	2	29.1	N	N
Scriba	345	55.3	5	46.8	N	N
Sherman Creek	138	63	2	45.5	N	N
Shore Road	345	63	3	27.8	N	N
Shore Road1	138	57.8	3	48.2	N	N
Shoreham1	138	52.2	3	28.2	N	N
Sprain Brook	345	63	2	51.9	N	N
St. Lawrence	230	37	7	33.7	N	N
Stolle Road	345	32	4	14.2	N	N
Stolle Road	230	28.6	4	5.1	N	N
Stoneyridge	230	40	4	7.1	N	N
Syosset	138	38.9	3	34.3	N	N
Tremont1	138	63	2	42.7	N	N
Tremont2	138	63	2	42.6	N	N
Motthaven	138	50	2	13.4	N	N
Vernon East	138	63	2	44.3	N	N
Vernon West	138	63	2	34.9	N	N
Valley Stream	138	63	3	53.7	N	N
Volney	345	45.1	5	36.5	N	N
West 49th Street	345	63	2	52.7	N	N
Wadngrv1	138	56.4	3	26.1	N	N
Watercure	230	26.4	4	13.2	N	N
Watercure	345	29.6	4	9	N	N
Weathersfield	230	40	4	9.1	N	N
Wildwood	138	63	3	28.2	N	N
Willis	230	37	7	12.7	N	N

Tables D-3 provides the results of NYISO's IBA for Fitzpatrick 345kV, Porter 230 kV, Astoria West 138 kV, Porter 115 kV, and Northport 138 kV.

Table D-3: NYISO IBA for 2014 RNA Study

Fitzpatrick 345 kV

Circuit Breaker	Rating	3LG	2LG	1LG	Overduty
10042	37 kA	32.4	34.5	34.1	N

Astoria W. 138 kV

Circuit Breaker	Rating	3LG	2LG	1LG	Overduty
G1N	45	38.9	42.38	44.15	N
G2N	45	38.9	42.38	44.15	N

Northport 138 kV

Circuit Breaker	Rating	3LG	2LG	1LG	Overduty
1310	56.2	52.02	52.5	50.98	N
1320	56.2	52.04	52.08	50.96	N
1450	56.2	49.01	50.83	51.82	N
1460	56.2	26.97	29.38	30.86	N
1470	56.2	31.94	32.43	32.67	N

East River 69 kV

Circuit Breaker	Rating	3LG	2LG	1LG	Overduty
53	50	42.8	44.9	46.1	N
63	50	44.9	44.8	46.1	N
73	50	42.7	44.9	46.1	N
83	50	42.8	45.5	47.1	N
GGT-2	50	39.7	41.6	42.8	N
Gen6	50	39.5	42.2	43.8	N

Porter 115 kV

BREAKER	DUTY_P	DUTY_A	BKR_CAPA	OVERDUTY
R10 LN1	102.1	43911.4	43000	Y
R100 TB3	85.1	36595.3	43000	N
R130 LN13	103	44307.7	43000	Y
R20 LN2	102.1	43910.7	43000	Y
R200 TB4	82.2	35336.9	43000	N
R30 LN3	101.8	43753.4	43000	Y
R40 LN4	101.7	43713.7	43000	Y
R50 LN5	101.7	43732.8	43000	Y
R60 LN6	103.1	44312.4	43000	Y
R70 LN7	101.1	43468.7	43000	Y
R80 LN8	102	43874.6	43000	Y
R8105 BUSTIE	87.7	41846.5	47714.9	N
R90 LN9	103.1	44317.5	43000	Y

Porter 230 kV

BREAKER	DUTY_P	DUTY_A	BKR_CAPA	OVERDUTY
R110 B-11	109.1	26023.6	23857.4	Y
R120 B-12	109.1	26023.6	23857.4	Y
R15 B-TB1	109.1	26023.6	23857.4	Y
R170 B-17	109.1	26023.6	23857.4	Y
R25 B-TB2	109.1	26023.6	23857.4	Y
R300 B-30	54.2	21686.3	40000	N
R310 B-31	54.2	21686.3	40000	N
R320 B-30	109.1	26023.6	23857.4	Y
R825 31-TB2	104.2	24870.9	23857.4	Y
R835 12-TB1	105.1	25082.5	23857.4	Y
R845 11-17	104.1	24825.9	23857.4	Y

D-5 Transmission Security Violations of the 2014 RNA Base Case

Zone	Owner	Monitored Element	Normal Rating (MVA)	LTE Rating (MVA)	STE Rating (MVA)	First Contingency	Second Contingency	2015 Flow (%)	2019 Flow (%)	2024 Flow (%)
A	N.Grid	Packard-Huntley (#77) 230 (Packard-Sawyer)	556	644	704	HUNTLEY - PACKARD 78 230	SB:ROBI230	-	-	100.75
A	N.Grid	Packard-Huntley (#78) 230 (Packard-Sawyer)	556	644	746	HUNTLEY - PACKARD 77 230	SB:ROBI230	-	-	100.73
A	N.Grid	Huntley-Gardenville (#79) 230 (Huntley-Sawyer)	566	654	755	HUNTLEY - GARDENVILL 80 230	SB:ROBI230	-	-	101.54
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755	HUNTLEY - GARDENVILL 79 230	SB:ROBI230	-	101.06	102.72
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755	ROBINSON - STOLLRD 65 230	HUNTLEY - GARDENVILL 79 230	-	100.47	106.6
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755	NIAGARA - ROBINSON 64 345	HUNTLEY - GARDENVILL 79 230	-	-	106.54
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755	LEEDS - HURLEY 301 345	HUNTLEY - GARDENVILL 79 230	-	-	103.79
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755	ATHENS - PV 91 345	HUNTLEY - GARDENVILL 79 230	-	-	103.33
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755	HQ-NY 765	HUNTLEY - GARDENVILL 79 230	-	-	103.32
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755	LEEDS - PV 92 345	HUNTLEY - GARDENVILL 79 230	-	-	103.32
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755	OS - EL - LFYTE 17 345	HUNTLEY - GARDENVILL 79 230	-	-	102.82
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755	NIAGARA - ROBINSON 64 345	T:78&79	-	-	102.79
A	N.Grid	Huntley-Gardenville (#80) 230 (Huntley-Sawyer)	566	654	755	ROBINSON - STOLLRD 65 230	T:78&79	-	-	102.56
B	RGE	Pannell 345/115 1TR	228	282	336	GEN:GINNA	SB:PANN345_1X12282	131.56	-	-
B	RGE	Pannell 345/115 1TR	228	282	336	GEN:GINNA	SB:ROCH_2T8082	103.97	-	-
B	RGE	Pannell 345/115 1TR	228	282	336	GEN:GINNA	PANL 345/115 2TR	103.84	-	-
B	RGE	Pannell 345/115 2TR	228	282	336	GEN:GINNA	SB:PANN345_3T12282	131.56	-	-
B	RGE	Pannell 345/115 2TR	228	282	336	GEN:GINNA	SB:ROCH_2T8082	103.97	-	-
B	RGE	Pannell 345/115 2TR	228	282	336	GEN:GINNA	PANL 345/115 1TR	103.84	-	-
B	RGE	Pannell 345/115 2TR	228	282	336	GEN:GINNA	SB:PANN345_3802	103.54	-	-
B	RGE	Pannell-Quaker (#914) 115	207.1	246.9	284.8	GEN:GINNA	PANL 345/115 3TR	120.41	-	-
B	RGE	Pannell-Quaker (#914) 115	207.1	246.9	284.8	GEN:GINNA	SB:PANN345_1X12282	100.73	-	-
B	RGE	Pannell-Quaker (#914) 115	207.1	246.9	284.8	GEN:GINNA	SB:PANN345_3T12282	100.73	-	-
C	N.Grid	Clay 345/115 1TR	478	637	794	OS - EL - LFYTE 17 345	SB:CLAY345_R130	-	111.53	118.77
C	N.Grid	Clay-Dewitt (#3) 115 (Clay-Bartell Rd)	116	120	145	CLAY - DEW 13 345	SB:OSWE_R985	104.57	-	-
C	N.Grid	Clay-Dewitt (#3) 115 (Clay-Bartell Rd)	116	120	145	OS - EL - LFYTE 17 345	CLAY - DEW 13 345	104.06	-	-
C	N.Grid	Clay-Dewitt (#3) 115 (Clay-Bartell Rd)	116	120	145	CLAY - DEW 13 345	T:17&11	102.89	-	-
C	N.Grid	Clay-Dewitt (#3) 115 (Clay-Bartell Rd)	116	120	145	CLAY - DEW 13 345	B:ELBRIDGE	102.87	-	-
C	N.Grid	Clay-Dewitt (#3) 115 (Clay-Bartell Rd)	116	120	145	CLAY - DEW 13 345	OS - EL - LFYTE 17 345	102.87	-	-
C	N.Grid	Clay-Dewitt (#3) 115 (Clay-Bartell Rd)	116	120	145	OS - EL - LFYTE 17 345	SB:CLAY345_R925	102.71	-	-
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	SB:OSWE_R985	N/A	121.61	135.18	139.48
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	SB:LAFA_ELB	N/A	121.51	133.23	139.79
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	B:ELBRIDGE	N/A	105.72	119.2	122.53
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	OS - EL - LFYTE 17 345	N/A	105.72	119.2	122.53

Zone	Owner	Monitored Element	Normal Rating (MVA)	LTE Rating (MVA)	STE Rating (MVA)	First Contingency	Second Contingency	2015 Flow (%)	2019 Flow (%)	2024 Flow (%)
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	ELBRIDGE 345/115 1TR	N/A	105.3	118.66	121.9
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	T:17&11	N/A	104.98	118.4	121.43
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	ELBRIDGE 345/115 1TR	Base Case	-	119.63	122.96
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	OS - EL - LFYTE 17 345	Base Case	-	119.14	120.84
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	CLAY - WOOD 17 115	SB:LAFA_ELB	137.49	169.93	180.03
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	CLAY - WOOD 17 115	SB:OSWE_R985	136.45	169.38	176.78
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	LFYTE - CLARKCRNS 36A 345	SB:OSWE_R985	127.59	149.95	158.11
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	ELBRIDGE 345/115 1TR	SB:CLAY115_R845	123.88	155.12	159.98
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	OS - EL - LFYTE 17 345	SB:CLAY115_R845	121.84	154.98	157.7
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	CLAY - WOOD 17 115	B:ELBRIDGE	119.37	151.94	157.77
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	CLAY - WOOD 17 115	OS - EL - LFYTE 17 345	119.37	151.94	157.77
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	ELBRIDGE 345/115 1TR	CLAY - WOOD 17 115	118.63	148.2	153.03
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	ELBRIDGE 345/115 1TR	S:CLAY115_WOOD_17	118.63	148.2	153.03
C	N.Grid	Clay-Lockheed Martin (#14) 115	116	120	145	HUNTLEY - GARDENVILL 79 230	SB:OSWE_R985	118.51	142.91	143.55
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	116	120	145	CLAY - TEAL 11 115	SB:DEWI345_R220	109.2	-	-
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	116	120	145	CLAY - TEAL 11 115	SB:DEWI345_R915	109.18	-	-
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	116	120	145	CLAY - TEAL 11 115	SB:DEWI345_R130	109.17	-	-
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	116	120	145	DEWITT 345/115 2TR	SB:CLAY115_R855	107.41	-	-
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	116	120	145	DEWITT 345/115 2TR	CLAY - TEAL 11 115	106.88	-	-
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	116	120	145	DEWITT 345/115 2TR	S:CLAY115_TEAL_11	106.88	-	-
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	116	120	145	CLAY - TEAL 11 115	DEWITT 345/115 2TR	105.34	-	-
C	N.Grid	Clay-Teall (#10) 115 (Clay-Bartell Rd-Pine Grove)	116	120	145	CLAY - DEW 13 345	SB:OSWE_R985	103.87	-	-
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	SB:LAFA_ELB	N/A	-	-	105.15
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	CLAY - LM 14 115	SB:LAFA_ELB	-	119.2	126.66
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	CLAY - LM 14 115	SB:OSWE_R985	-	113.05	118.41
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	GEN:GINNA	SB:LAFA_ELB	-	110.13	111.87
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	NIAGARA - ROBINSON 64 345	SB:LAFA_ELB	-	108.52	108.45
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	EDIC - FRASER 345 SC	SB:LAFA_ELB	-	107.88	112.72
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	ROBINSON - STOLLRD 65 230	SB:LAFA_ELB	-	107.67	107.96
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	HUNTLEY - GARDENVILL 79 230	SB:LAFA_ELB	-	106.9	108.4
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	OS - EL - LFYTE 17 345	SB:CLAY115_R865	-	106.49	108.46
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	PANL - CLAY PC-1 345	SB:LAFA_ELB	-	106.18	112.4
C	N.Grid	Clay-Woodard (#17) 115 (Euclid-Woodward)	174	174	174	PANL - CLAY PC-2 345	SB:LAFA_ELB	-	106.17	112.45
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	104	104	104	CLAY 345/115 1TR	SB:CLAY345_R130	-	109.56	112.9
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	104	104	104	OSW - VOL 12 345	T:17&11	-	-	107.75
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	104	104	104	CLAY 345/115 2TR	SB:CLAY345_R35	-	100.01	103.54
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	104	104	104	CLAY 345/115 1TR	SB:CLAY345_R60	-	-	102.35
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	104	104	104	CLAY 345/115 2TR	SB:CLAY345_R260	-	-	102

Zone	Owner	Monitored Element	Normal Rating (MVA)	LTE Rating (MVA)	STE Rating (MVA)	First Contingency	Second Contingency	2015 Flow (%)	2019 Flow (%)	2024 Flow (%)
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	104	104	104	OS - EL - LFYTE 17 345	SB:CLAY345_R130	-	-	101
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	104	104	104	CLAY 345/115 2TR	SB:CLAY345_R80	-	-	100.96
C	N.Grid	S. Oswego-Clay (#4) 115 (S. Oswego-Whitaker)	104	104	104	CLAY 345/115 1TR	SB:CLAY345_R45	-	-	100.87
C	N.Grid	Oakdale 345/115 2TR	428	556	600	OKDLE 345/115 3TR	Base Case	-	102.85	103.75
C	N.Grid	Oakdale 345/115 2TR	428	556	600	FRASER 345/115 2TR	SB:OAKD345_31-B322	-	103.2	105.42
C	N.Grid	Oakdale 345/115 2TR	428	556	600	WATERCURE 345/230 1TR	SB:OAKD345_B3-3222	102.88	-	-
C	N.Grid	Oakdale 345/115 3TR	428	556	600	OKDLE 345/115 2TR	Base Case	-	-	102.22
E	N.Grid	Porter-Oneida (#7) 115 (Porter-W. Utica)	116	120	145	OS - EL - LFYTE 17 345	SB:CLAY345_R130	-	101.87	104.16
E	N.Grid	Porter-Oneida (#7) 115 (Porter-W. Utica)	116	120	145	CLAY - DEW 13 345	SB:OSWE_R985	-	-	104.73
E	N.Grid	Porter-Oneida (#7) 115 (Porter-W. Utica)	116	120	145	PTR YAHN 115	SB:OSWE_R985	-	101.06	-
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	OS - EL - LFYTE 17 345	SB:CLAY345_R130	106.37	117.17	118.53
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	CLAY - DEW 13 345	SB:OSWE_R985	104.82	115.54	119.01
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	CLAY 345/115 1TR	SB:CLAY345_R130	100.43	113.63	113.46
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	OS - EL - LFYTE 17 345	SB:CLAY345_R925	-	108.25	108.91
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	CLAY 345/115 1TR	SB:OSWE_R985	-	107.77	108.23
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	CLAY 345/115 2TR	SB:OSWE_R985	-	107.53	108.02
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	CLAY - DEW 13 345	B:ELBRIDGE	-	106.13	108.79
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	CLAY - DEW 13 345	OS - EL - LFYTE 17 345	-	106.13	108.79
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	CLAY - DEW 13 345	T:17&11	-	105.85	108.52
F	N.Grid	New Scotland 345/115 1TR	458	570	731	GEN:BETHSTM	Base Case	-	-	106.05
E	N.Grid	Porter-Yahnundasis (#3) 115 (Porter-Kelsey)	116	120	145	PTR TRMNL 115	S:PTR115_SCHLR	-	-	110.12
F	N.Grid	New Scotland 345/115 1TR	458	570	731	GEN:BETHSTM	B:N.S._77	110.56	115.54	146.76
F	N.Grid	New Scotland 345/115 1TR	458	570	731	GEN:BETHSTM	N.SCOT77 345/115 2TR	106	110.45	128.17
F	N.Grid	New Scotland 345/115 1TR	458	570	731	N.SCOT77 345/115 2TR	G:BETHSTM	-	108.85	125.99
F	N.Grid	New Scotland 345/115 1TR	458	570	731	GEN:BETHSTM	S:Reynolds-Rey 345/115	-	-	120.76
F	N.Grid	New Scotland 345/115 1TR	458	570	731	GEN:BETHSTM	S:EMPIRE	-	-	119.66
F	N.Grid	New Scotland 345/115 1TR	458	570	731	N.SCOT99 - LEEDS 94 345	B:N.S._77	-	-	111.99
F	N.Grid	Reynolds 345/115	459	562	755	GEN:BETHSTM	Base Case	107.06	108.49	127.15
F	N.Grid	Reynolds 345/115	459	562	755	EASTOVER - BEARSWMP 230	G:BETHSTM	-	-	126.12
F	N.Grid	Reynolds 345/115	459	562	755	EASTOVER 230/115 1XTR	GEN:BETHSTM	-	-	121.86
F	N.Grid	Reynolds 345/115	459	562	755	GEN:BETHSTM	N.SCOT77 345/115 1TR	-	-	120.57
F	N.Grid	Reynolds 345/115	459	562	755	N.SCOT77 345/115 2TR	GEN:BETHSTM	-	-	117.66
F	N.Grid	Reynolds 345/115	459	562	755	N.SCOT77 345/115 1TR	GEN:BETHSTM	-	-	115.31
F	N.Grid	Reynolds 345/115	459	562	755	LEEDS - HURLEY 301 345	ALPS - REYNOLDS 1 345	-	-	101.44
F	N.Grid	Rotterdam 230/115 7TR	300	355	402	EASTOVER 230/115 1XTR	SB:ROTT_230_R84	123.31	112.59	122.44
F	N.Grid	Rotterdam 230/115 7TR	300	355	402	ROTTERDAM 230/115 1XTR	ROTTERDAM 230/115 3XTR	-	-	116.41
F	N.Grid	Rotterdam 230/115 7TR	300	355	402	ROTTERDAM 230/115 3XTR	ROTTERDAM 230/115 1XTR	-	-	116.32

Zone	Owner	Monitored Element	Normal Rating (MVA)	LTE Rating (MVA)	STE Rating (MVA)	First Contingency	Second Contingency	2015 Flow (%)	2019 Flow (%)	2024 Flow (%)
F-G	N.Grid	Athens-Pleasant Valley (#91) 345	1331	1538	1724	LEEDS - PV 92 345	T:41&33	-	-	102.98
F-G	N.Grid	Athens-Pleasant Valley (#91) 345	1331	1538	1724	LEEDS - PV 92 345	T:34&42	-	-	100.74
F-G	N.Grid	Leeds-Pleasant Valley (#92) 345	1331	1538	1724	ATHENS - PV 91 345	T:41&33	-	-	103.2
F-G	N.Grid	Leeds-Pleasant Valley (#92) 345	1331	1538	1724	ATHENS - PV 91 345	T:34&42	-	-	100.94

Exhibit No. NYT-11

PUBLIC VERSION
PRIVILEGED AND CONFIDENTIAL INFORMATION REMOVED
PURSUANT TO 18 C.F.R. § 388.112

Exhibit No. NYT-12

PUBLIC VERSION
PRIVILEGED AND CONFIDENTIAL INFORMATION REMOVED
PURSUANT TO 18 C.F.R. § 388.112

Exhibit No. NYT-13

PUBLIC VERSION
PRIVILEGED AND CONFIDENTIAL INFORMATION REMOVED
PURSUANT TO 18 C.F.R. § 388.112

Exhibit No. NYT-14

Major Project Permits and Approvals

Government Agency or Regulatory Body	Permit or Approval Required	AC Projects: Edic-Pleasant Valley 345kV Line	AC Projects: 2nd Oakdale-Fraser 345kV Line	TOTS Projects: 2nd Ramapo-Rock Tavern 345kV Line	TOTS Projects: Fraser-Coopers Corners Reconductoring	TOTS Projects: Staten Island Unbottling (SIU)
US ACE	Sec. 404 – Clean Water Act Permit	Y	Y	Y	Y	N
USFWS	Threatened & Endangered Species – Decision of No Impacts	Y	Y	N	Y	N
FAA	Notice of Construction or Alteration	Y	N	N	N	N
NY PSC	Certificate of Environmental Compatibility and Public Need	Y	Y	Y	N	N
NY PSC	Environmental Management & Construction Plan approval	Y	Y	Y	N	N
NY DEC	State 401 Water Quality Certificate	Y	Y	Y	N	N
NY DEC	General Permit for Stormwater Discharges from construction activities (SWPPP)	Y	Y	Y	N	Y
NY DEC	Application for Temporary Revocable Permit – provides for temporary use of NY State Lands (Catskill Park)	N	N	N	Y	N
NY DEC	SEQRA – Seeking a negative declaration which is a determination that no significant adverse environmental impact will occur from construction of the project	N	N	N	Y	N
NY DOT	Utility Work Permit	Y	Y	Y	Y	N
NY OPRHP	Finding of no significant adverse effects on cultural resources (National Historic Preservation Act)	Y	Y	Y	Y	N
NJ DEP	Waterfront Development Law, wetlands act	N	N	N	N	Y

Major Project Permits and Approvals

		AC Projects		TOTS Projects		
Government Agency or Regulatory Body	Permit or Approval Required	Edic-Pleasant Valley 345kV Line	2nd Oakdale-Fraser 345kV Line	2nd Ramapo-Rock Tavern 345kV Line	Fraser-Coopers Corners Reconductoring	Staten Island Unbottling (SIU)
NYC DEP	SWPPP Approval	N	N	N	Y	N
NYC Department of Buildings	Building Permits	N	N	N	N	Y
NYC Zoning Board	Land use approval	N	N	N	N	Y
Delaware River Basin Commission	Project review	N	N	N	Y	N
Orange County Parks, Recreation & Conservation	Access approval	N	N	Y	N	N
Orange County Soil & Water Conservation District	Project review	N	N	Y	N	N
Rockland County Drainage Agency	Project review	N	N	Y	N	N
Rockland County Soil & Water Conservation District	Project review	N	N	Y	N	N
County DPW (various)	Highway Work Permit	Y	Y	Y	Y	N
Delhi, Town of	Special Use Permit/Site Plan Review	N	N	N	Y	N
Ramapo, Town of	Building Permit	N	N	Y	N	N
Town, City, Village (various)	Municipal Stormwater Review	Y	Y	N	N	N
Railroad Company (various)	ROW Entry Permit	Y	N	Y	N	N
Railroad Company (various)	ROW Construction Authorization	Y	N	Y	N	N

Exhibit No. NYT-15

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
Albany on October 23, 2014

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Garry A. Brown
Gregg C. Sayre
Diane X. Burman

CASE 13-T-0586 – Petition of Consolidated Edison Company of New York, Inc. for Approval of Environmental Management and Construction Plan for Sugarloaf to Rock Tavern Segment of Second Ramapo to Rock Tavern 345 kV Transmission Line (Feeder 76). (Formerly Cases 25845 and 25741).

ORDER APPROVING ENVIRONMENTAL MANAGEMENT & CONSTRUCTION PLAN
SEGMENT II

(Issued and Effective October 27, 2014)

BY THE COMMISSION:

INTRODUCTION AND BACKGROUND

In 1972, the Commission granted Consolidated Edison Company of New York, Inc. (Con Edison or the Company), a Certificate of Environmental Compatibility and Public Need (Certificate)[1] for the construction and operation of approximately 64 miles of 345 kV transmission lines through portions of Rockland, Orange and Sullivan counties in southeastern New York. One segment, known as the North-South

[1] Cases 25845 and 25741, Consolidated Edison Company of New York, Inc., Opinion No. 72-2, Opinion and Order Granting Certificate of Environmental Compatibility and Public Need with Conditions (issued January 25, 1972).

leg, as proposed by Con Edison, was approximately 26 miles long connecting the Orange and Rockland Utilities, Inc.'s (ORU) Ramapo Substation in Rockland County with a Central Hudson Gas & Electric Corporation (Central Hudson) Substation at Rock Tavern, Town of New Windsor, Orange County. The East-West leg connected the Rock Tavern substation with the New York State Electric and Gas Corporation (NYSEG) Coopers Corners substation in the Town of Thompson, Sullivan County. The East-West leg was constructed and has been in operation since the mid-1970's. The North-South leg is in consideration. Originally, Con Edison requested approval for a single 345 kV circuit between Ramapo and Rock Tavern with sufficient right-of-way (ROW) for an additional single circuit to be constructed in the future. However, the Commission approved the construction of a single 345 kV circuit on double-circuit structures between Ramapo and Rock Tavern. The expectation was that the second 345 kV circuit would be needed no later than the late 1980's and no earlier than the late 1970's if construction of Con Edison's anticipated generation plants were delayed. The Commission's Order in Case 25741, clause 2.C., stated that "…the second circuit may be strung after prior notice to the Commission." The second circuit did not become necessary until 2008 when Con Edison and ORU filed for the proposed leasehold transfer and the subsequent EM&CP approval on June 9, 2010.

The joint petition of Con Edison and ORU was subsequently amended on September 1, 2010, after which the Commission approved the transfer of a portion of the Certificate to ORU, authorized ORU to install, operate, and maintain an additional circuit on existing transmission towers in Con Edison's ROW, and approved the EM&CP for the stringing of the second circuit between the Ramapo and Sugarloaf substations.[2] The Commission also approved a lease agreement permitting the use of Con Edison's towers.[3] By petition filed July 3, and amended July 9, 2013, ORU requested the Commission amend a condition contained in the January 2011 Order that required ORU to obtain all required permits and approvals and submit copies to the Secretary of the Commission prior to commencing construction. ORU requested authorization to commence construction prior to obtaining the permit to cross the New York State Thruway as it was a contractual obligation of the electrical contractor to secure the permit. The Commission granted the petition.[4] Segment I of the approved EM&CP is presently under construction and slated for completion by June 1, 2016.

On December 31, 2013, Con Edison filed and served the proposed EM&CP for the Feeder 76 segment from the Sugarloaf Substation to the Rock Tavern Substation.[5] On January 27, 2014, the New York State Department of Environmental Conservation (DEC) requested an extension to file comments on the EM&CP for the Sugarloaf to Rock Tavern segment. The Commission Secretary granted all parties a comment extension to March 3, 2014.

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[2] Case 10-T-0283, Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., Order Approving Transfer and Environmental Management and Construction Plan (issued January 24, 2011).

[3] Case 08-M-0772, Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., Order Approving Lease Transaction (issued January 24, 2011).

[4] Case 10-T-0283, supra, Order Approving Petition (issued July 16, 2013).

[5] The Company supplemented the EM&CP on May 27, 2014 and served the supplement as required.

Comments on the EM&CP were received from DEC, the New York State Department of Agriculture and Markets (DAM), Central Hudson, and Entergy Nuclear Fitzpatrick, Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc. (collectively referred to as Entergy). The Staff of the Department of Public Service (DPS) provided informal comments to Con Edison. Additional comments on the supplement were received from DAM on June 30, 2014.

Con Edison submitted the Storm Water Pollution Prevention Plan Notice of Intent to DEC on August 22, 2014. On August 28, 2014, Con Edison submitted a revised EM&CP for our review and approval and requested a Water Quality Certification (WQC) pursuant to §401 of the Federal Water Pollution Control Act 33 U.S.C. §1341.

SUMMARY OF COMMENTS AND RESPONSES

DEC requested several revisions to the EM&CP text and drawings regarding identification and protection of natural resources that included: identification of streams and wetlands and the revised measures to protect them; prohibition of the use of fords for temporary access across streams; requirement to clean all mats used in wetlands and streams before removal; employment of an experienced Timber Rattlesnake monitor (biologist) during construction, between Structures S99 and S116, from April 1 to October 31; tree clearing from October 31 to March 31 only, due to proximity of a known Hibernacula for Indiana bats;[6] avoidance of Bog turtle and potential Bog turtle wetland habitats or, in the alternative, adherence to the particular "Avoidance and Minimization Measures" specified by

[6] A United States Fish and Wildlife Service fact sheet is provided with the comments.

DEC including employment of an experienced on-site monitor during construction; and, application of protection measures for critical habitat to Con Edison's Long-Range Right-of-Way Management Plan, filed in accordance with 16 NYCRR §84.2.

In response, Con Edison agreed to brush clean construction mats before removal to minimize the unintentional transportation of invasive plant species. The company noted, however, that if mats cannot adequately support equipment across wetlands, filter fabric and stone would be used for work in those areas. If used, the fabric and stone would be removed and the area would be regraded and seeded to preconstruction conditions. It also agreed to avoid the use of temporary fords for access.

The Company further responded that Sections 3.4.3.2 and 3.4.4.4 of the EM&CP, with notes placed upon the drawings, were revised to indicate that an experienced Timber rattlesnake monitor would be employed during construction in this area from April 1 to October 31, or that a seasonal work window of November 1 to March 31 would be observed, including the area between structures S99 and S116 (inclusive). Sections 3.4.4.4 and 4.1.1 of the EM&CP were revised (with notes on the EM&CP drawings) to indicate that any tree clearing would be conducted from October 31 to March 31. For any tree clearing that is necessary outside the stated time period, Con Edison explained that it would consult with DEC.

The Company also agreed to avoid wetlands labeled 'Bog turtle' and 'potential bog turtle' and those wetlands where further turtle surveys are not planned. Sections 3.4.3.2, 3.4.4.4 and 4.1.1 of the EM&CP were revised (with notes on the EM&CP drawings) to describe the avoidance and impact minimization measures to be employed when accessing the transmission structures in these wetlands.

Finally, Con Edison asserted that its present ROW management practices already include controls such as seasonal timing restrictions to protect critical habitat and consultation with the Regional DEC Offices to ensure the Company's practices avoid or minimize adverse impacts.

DAM suggested that EM&CP Section 3 of the Assessment of Environmental Conditions and Impacts be revised to include impacts to agricultural land use and to identify all agricultural areas on the Plan and Profile drawings. In the General Cleanup and Restoration section, DAM requested that the section explain how the environmental monitor will determine if decompaction of active agricultural soils is necessary. DAM proposed that all construction work areas in agricultural land be decompacted with rocks 4-inches or larger removed before topsoil replacement and seeding.

In its June 30, 2014 comments, DAM reiterated comments made in its January 28, 2014 letter that all agricultural areas should be identified on the EM&CP drawings. DAM stated that there is general information on land use on the EM&CP drawings but the drawings do not provide site-specific land use information and do not appear to be accurate. DAM pointed out that transmission structures #117 and #118, located in Orange County Agricultural Districts, are in actively used agricultural fields and that conductor installation would require a stringing and anchor site in an agricultural field presently used as a pasture. DAM asked that the EM&CP drawings show the access across the pasture to the stringing site and that the text describe the measures to be taken to keep livestock out of the work site.

In response, Con Edison noted that Figures 3.1-1 through 3.1-10 depict known agricultural land uses and indicate that existing access roads will be used, with construction vehicles confined to those roads and work areas. The restoration of actively used agricultural fields, the methods of determining soil compaction and fence repair and replacement were revised and are addressed in Section 12.2 of the EM&CP text. The Company explained that all work areas in agriculturally used land will be decompacted, with rocks that are 4 inches in diameter or larger removed from subsoil and topsoil prior to seeding. Regarding the pasture to be crossed to reach the stringing site, Con Edison stated that it plans to fence and install a gate or contact the property owner to relocate any cattle grazing in the area during the conductor stringing operations.

Entergy's comments alleged that Con Edison's submission of the EM&CP was procedurally deficient due to the lack of service of the Ramapo to Rock Tavern Petition on the parties to Cases 12-E-0503 and 13-E-0488.[7] Entergy requested that the Commission direct Con Edison to amend its petition to specify that it would seek the approval of the Federal Energy Regulatory Commission (FERC) for the cost allocation and recovery associated with Feeder 76 (also known as the Ramapo to Rock Tavern 345 kV transmission facility). Entergy further alleged that Con Edison's conclusory statements were not sufficient to demonstrate substantive compliance with local laws and noted that, to the extent that the EM&CP does not comply with local laws, Con Edison must petition for an amendment to its Article VII Certificate. Entergy further asserted that the proposed project would exceed the Commission's electric field standards for 14 of the 178 spans of the Ramapo to Rock Tavern 345 kV transmission facility.

[7] Case 12-E-0503, Generation Contingency Retirement Plans; Case 13-E-0488, Alternating Current Transmission Upgrades - Comparative Proceeding.

In response, Con Edison noted that it served its proposed EM&CP on parties to Cases 13-M-0457 and 13-E-0488.[8] The proposed EM&CP presents Con Edison's review of local legal requirements. According to the Company, it shows that electrostatic fields of greater than 1.6 kV/m would occur less than 0.1% of the time that the transmission facility is in operation.

Central Hudson's comments related to the Rock Tavern substation. Specifically, it requested that the expansion of the Rock Tavern substation be shown on the Plan and Profile drawings and that the existing access road along the western and southern perimeter of the existing substation be extended and improved and correctly noted on the Plan and Profile drawings. It also requested that the new tower for the relocated Circuit 77 transmission line be located outside the substation fence and correctly depicted on the drawings. Con Edison addressed Central Hudson's comments in its revised EM&CP filed August 28, 2014.

DPS Staff provided informal comments to the Company, seeking clarification and additional information on a number of construction and design related issues. Specifically, DPS requested: Identification of the structures that required reinforcement of steel members and/or foundations; provision of catalog cut sheets showing the original and proposed hardware if original hardware is no longer available for exact matches; provision of the site plans, elevations, grading and drainage for the Sugarloaf 345/138 kV substation and step-down transformer; provision of the drawings showing the relocation of the 69 kV circuit to accommodate the 345/138 kV substation;

[8] Case 13-M-0457, New York Transmission Owners; Case 13-E-0488, Supra.

provision of the construction drawings and site plans for the Ramapo, Sugarloaf, and Rock Tavern substations including new terminal structures, expanded substation bays and control rooms; provision of additional information that shows the off ROW access tie-in to public roads; a showing on construction drawings of no equipment access between structures and off ROW access, the location of access roads to structures and work areas, removal of multiple access roads where one road is necessary, gate installation, the block of all terrain vehicle access to the ROW, identification of measures (regarding safety and public protection) to be taken when stringing operations (the pulling of lead lines and conductor) will cross municipal highways; provision of measurements of the preexisting noise levels before the construction of the Sugarloaf substation; performance of a noise impact analysis following the guidelines provided by DPS and DEC's noise policy; provision of ground elevations, a substation site grading plan, transformer and emergency generator enclosure dimensions, sound power or pressure levels for the transformer and emergency generator, a topographical map with the substation property boundaries and nearby residential receptors, assumed ground (sound) absorption, temperatures, and relative humidity, as well as an explanation on how prominent tones would be addressed for the proposed transformer; provision of supplemental information on construction noise and mitigation following the guidelines; a plan on how complaints due to construction noise will be handled; specification of whether or not construction activities will take place on weekends or holidays; and clarification of whether the metric for the 45 dBA indoor reference value is the DLN (or Ldn, as defined and recommended by EPA-550/9-74-00413) and clarification of any plans proposed for the Sugarloaf

345/138 kV substation site. DPS Staff asked Con Edison to indicate its plans for the site.

In response to the informal comments of DPS, Con Edison made several revisions to the proposed EM&CP. The Company also provided a significant amount of supporting information. Because Con Edison determined that the 69 kV circuit would not have to be relocated to accommodate the location of the substation, it did not provide drawings showing the relocation. Issues relating to noise are addressed in detail further below.

DISCUSSION AND CONCLUSION

Con Edison appropriately revised Sections 3 and 4 of the EM&CP text and the Plan and Profile drawings to reflect DEC's comments. As for DEC's comments on the Company's Long Range Right-of-Way Management Plan, they are appropriately dealt with in Case 04-E-0822,[9] not in this proceeding dealing with the approval of the EM&CP regarding a specific transmission line. Similarly, Con Edison appropriately responded to the comments of DAM and Central Hudson by making necessary revisions to the EM&CP.

We reject Entergy's claim that Con Edison should have served its proposed EM&CP on parties to Case 12-E-0503 because that case does not involve the manner in which transmission lines will be constructed. Because the Ramapo to Rock Tavern project was listed as one of the projects to be considered in Case 13-E-0488, Con Edison served its proposed EM&CP on parties

[9] Case 04-E-0822, New York State's Electric Utility Transmission Right-of-Way Management Practices, filed in C 27605.

to that case and Case 13-M-0457, supra.[10] Moreover, the Secretary invited comments on the proposed EM&CP from parties to those cases. We also reject Entergy's request that we direct Con Edison to seek FERC approval for the cost allocation and recovery associated with Feeder 76. A requirement to file for a cost allocation and recovery mechanism is outside the scope of this proceeding, which deals with the specifics of the Company's construction plans.

In connection with Entergy's comment regarding the need to comply with local laws, such laws and ordinances were reviewed by Con Edison and further reviewed by DPS Staff to ensure that the Company would comply with them. Sections 5 through 13 of the EM&CP show how compliance with the substantive parts of the local laws and ordinances will be assured. As for Entergy's comment that the proposed project would exceed the Commission's electric field standards for 14 of the 178 spans of the Ramapo to Rock Tavern 345 kV transmission facility, we note that the addition of the second 345kV circuit actually causes a cancelling effect of the electric field values due to phasing. When measured four feet from the conductor, the Commission's standard of 1.6kV/m at the edge of the ROW is met.

With respect to noise, Con Edison provided surveyed ambient sound levels and estimated noise impacts at two locations on the western Sugarloaf property line. It also provided estimated noise impacts from the proposed substation at one location approximately 215 feet east of the transformer on the easterly Sugarloaf substation property line. The Commission is advised that the modeling resulted in a noise level of 37.3

[10] Con Edison withdrew its Ramapo to Rock Tavern transmission line project from consideration in Cases 13-M-0457 and 13-E-0488, supra, on September 11, 2014.

dBA Leq. Con Edison supplied the modeling result on the easterly property line to DPS Staff for informational purposes, but did not include it in the revised noise report. The Company provided a substation site grading plan showing the property boundaries and locations of nearby residential noise receptors, as well as substantially all of the requested information. Con Edison has requested bids for a transformer that produces an overall noise emission performance specification meeting 67dBA Leq at a distance of one meter with no prominent tones. When the bids are received and evaluated, Con Edison will provide DPS Staff with a copy of the accepted performance specification. Con Edison also informed DPS Staff, based on the computer noise model, that the sound level at 50 feet from the proposed transformer will be 49 dBA.

Con Edison indicated that construction is not generally scheduled for weekends or holidays. It will make the necessary arrangements with the local agencies in compliance with local ordinances and will notify DPS Staff and community representatives at least 24 hours in advance of any planned weekend or holiday work. The Town of Chester's land use controls and ordinances do not provide specific sound levels for noise-producing equipment, such as the Sugarloaf Substation's 345 kV/138 kV stepdown transformer; however, the Town of Chester Zoning Ordinance §98-17, Prohibited Uses, states land uses prohibited are those that are "… noxious, offensive or objectionable … by reason of the creation of noise, … [that] cause injury, annoyance or disturbance to any of the surrounding properties or to their owners and occupants, and any other process or use which is unwholesome and noisome and may be dangerous or prejudicial to health, safety or general welfare." Given that Con Edison stated that it would comply with the substantive requirements of the local ordinances, we will require the Company to revise its operational noise study to contain not only all of the measured ambient sound levels, but also modeled sound levels and impacts for the Sugarloaf substation at the most critical property lines.

Con Edison supplied a combined noise analysis of the 345 kV/138 kV substation transformer and emergency generator. According to the Company, the modeling indicates that operating the transformer and generator simultaneously will be lower than the 6 dBA threshold mentioned in DEC's Noise Policy. Con Edison stated that the emergency generator with muffler and enclosure had been specified for 60 dBA at 1 meter and that the noise levels at 50 feet are 39 dBA as extracted from the computer model. While existing ambient noise levels should be described in terms of the L90 statistical descriptor instead of the Leq noise descriptor, the Applicant conservatively selected low values of the Leq; thus the use of the L90 descriptor may arrive at similar results in this case. When Con Edison undertakes the operational noise study, we expect these issues to be addressed in the required report.

Recent wetland delineation by ORU in the vicinity of Tower S95 and the planned Sugarloaf step-down transformer indicated a potential Federal jurisdictional wetland. By letter dated August 27, 2014, attached to the EM&CP supplement, Con Edison requested that a WQC be issued under Section 401 of the Federal Clean Water Act (CWA) for activities related to the construction of the facilities associated with the installation of the second circuit on the existing Sugarloaf-Rock Tavern Transmission facility. The CWA requires a federal permit to discharge dredged or fill material into navigable waters (33 U.S.C. §§ 1311(a) and 1342 (a) and requires an applicant for a permit to provide certification from the State that the discharge will comply with the State's water quality standards.

CWA §410 defines “navigable waters” as waters of the United States, including the territorial seas (33U.S.C. §1362(7)). The U. S. Army Corps of Engineers (USACE), which issues the permits, defines these waters to include tributaries and other types of water sources. Con Edison is presently seeking a USACE Nationwide Permit No. 12 and will apply for other federal permits if required.

Appropriate conditions will be imposed in accordance with the discussion above to assure that the Company complies with applicable state water quality standards. Given the ministerial nature of the decisions to grant WQCs and the normal 60-day period for granting the certifications established in 33 CFR §325.2(b)(1)(ii), the Commission has delegated the responsibility for granting WQCs in connection with Article VII Certificates to the Director of the Office of Energy Efficiency and the Environment. As requested, the Director will issue the WQC after the issuance of this Order.

The Commission orders:

1. The Environmental Management and Construction Plan (EM&CP) for the installation of the second circuit, known as Line 76, between the new Sugarloaf substation and the Rock Tavern substation (including work at the Ramapo, Sugarloaf and Rock Tavern Substations) filed on August 28, 2014, by Consolidated Edison Company of New York, Inc., (the Company) is approved, subject to the following conditions and modifications:

a. The Company shall report any proposed changes to the approved EM&CP to Staff. Staff will refer any proposed changes that will not result in any increase in adverse environmental impacts or are not directly related to contested issues decided during the proceeding to the Director of the Office of Energy

Efficiency and the Environment (OEEE) for approval. Staff will refer all other proposed changes to the Commission for approval. Upon being advised that Staff will refer a proposed change to the Commission, the Company shall notify all parties to this proceeding, as well as property owners and lessees whose property is affected by the proposed change. The notice shall: (1) describe the original conditions and the requested change; (2) state that documents supporting the request are available for inspection at specified locations, and (3) state that persons may comment by writing or calling (followed by written confirmation) to the Commission within twenty-one (21) days of the notification date. Any delay in receipt of written confirmation will not delay Commission action on the proposed change. The Company shall not execute any proposed change until it has received oral or written approval, except in emergency situations threatening personal injury, property, or severe adverse environmental impact. Any oral approval from Staff will be followed by written approval from the Director of OEEE or the Commission;

b. The company shall designate a full-time supervisor with stop-work authority over all aspects of this project; the supervisor shall be onsite during all phases of construction and restoration; the full-time supervisor and the environmental and construction monitors shall be equipped with sufficient documentation, transportation, and communication equipment to effectively monitor contractor compliance with provisions of this Order: applicable sections of the Public Service Law and the EM&CP; the names and qualifications of the Company's construction supervisor and environmental monitor(s) shall be submitted to Staff at least 15 days prior to the start of construction for review and approval;

c. The Company shall provide construction contractors with complete copies of the EM&CP, the Storm Water Pollution Prevention Plan (SWPPP) and any site-specific plans;

d. The Company shall notify all construction contractors that the Commission may seek to recover penalties for violations of its Orders, not only from the Company, but also from its construction contractors; construction contractors may also be liable for other fines, penalties and environmental damage;

e. The Company shall notify the Secretary to the Commission (Secretary) of the proposed commencement date at least 10 days prior to the start of construction;

f. At least 10 days prior to the start of construction, the Company shall hold a pre-construction meeting. An agenda, location and attendee list shall be agreed upon between Staff and the Company. The Company shall provide draft minutes from this meeting to all attendees; the attendees may offer corrections or comments, and the Company, in consultation with Staff, shall issue the finalized meeting minutes to all attendees.

g. Should culturally significant resources be encountered during construction, the Company shall stabilize the area and cease construction in the immediate vicinity of the find and protect the same from further damage. The Company shall notify Staff and the New York State Office of Parks, Recreation and Historic Preservation Field Services Bureau to determine the best course of action. No construction activities shall be permitted in the vicinity of the find until such time as the significance of the resource has been evaluated and the need and scope of impact mitigation has been determined;

h. Before construction begins, the Company shall provide the Secretary with a signed copy of the New York State Department of Environmental Conservation's approval of the Company's SWPPP and a copy of the U.S. Army Corps of Engineers Nationwide permit approval;

i. Construction equipment coming onto the right-of-way (ROW) for the first time shall be cleaned prior to arrival at the construction site. Construction equipment leaving the construction site(s) for the final time shall be cleaned as well;

j. The certified work is subject to inspection by authorized representatives of Staff;

k. Prior to construction in the affected areas, the Company shall provide to the Secretary a copy of each local, state and federal permit affecting such area;

l. In order to comply with the New York State Uniform Fire Prevention and Building Code (UFPBC):

(1) Before the start of construction of the expanded control buildings at the Ramapo and Rock Tavern substations and the new control building at the Sugarloaf Substation, the Company shall first obtain review and written certification by a public entity recognized by the Department of State (DOS) as having the requisite training or

qualifications that the construction plans are in compliance with the UFPBC;

(2) Within 10 days of receiving any written certification as described in "(1)" above, the Company shall file a copy of such certification with the Secretary;

(3) During the construction, the Company shall obtain periodic inspections of the construction work by a public entity recognized by the DOS as having the requisite training or qualifications to inspect such work for compliance with the UFPBC;

(4) Prior to the use or occupancy of the expanded control buildings at the Ramapo and Rock Tavern substations and the new control building at the Sugarloaf Substation, the Company shall first obtain written certification by a public entity recognized by the DOS as having the requisite training or qualifications that the construction was completed in compliance with the UFPBC; and

(5) Within 10 days of receiving any written certification as described in "(4)" above, the Company shall file a copy of such certification with the Secretary;

m. the Company shall comply with applicable requirements of Sections 301, 302, 303, 306 and 307 of the Federal Water Pollution Control Act, as amended, and applicable New York State water quality standards, limitations, criteria and other requirements set forth in 6 NYCRR § 608.9(c) and Parts 701 through 704;

n. Within 10 days after the ROW is completely restored, the Company shall notify Staff and the Secretary in writing;

o. Within 45 days after the commencement of operation of the Sugarloaf substation, the Company shall file with the Secretary a report from an independent acoustical consultant, in sufficient detail for Staff to determine any increase in ambient sound levels at the property lines and any residential receptor, with the substation working under the worst operational noise conditions, with and without the emergency generator running under testing operation; the noise survey supporting the report shall be performed at daytime and nighttime, by following a sound protocol previously submitted and approved by Staff; the sound protocol shall contain, among other items, instrumentation requirements, selected measurement locations, acceptable weather conditions, noise descriptors, frequencies of interest, duration, times of testing, and any other relevant and applicable topics from American National Standards Institute standards related to sound instrumentation and measurement of sound; and

p. If the noise survey and report show that the noise produced by the Sugarloaf substation causes an increase in the ambient sound levels at any existing residential receptor or property line of 6 dBA or more, including a 5 dBA penalty on measured sound levels if a prominent tone occurs at the evaluated receptors, or if excessive low frequency noise produced by the emergency generator, muffler and enclosure causes airborne induced vibrations on any residential building, the Company shall, within 180 days after commencement of operation of the Sugarloaf substation, provide noise mitigation such as noise barriers, berms, enclosures or silencers, and reduce any of these conditions; the Company shall submit mitigation plans to Staff and resubmit a post-mitigation noise survey demonstrating that any of these conditions are resolved.

2. The Company shall not commence construction until it has received a "Notice to Proceed with Construction" sent by the director of OEEE.

3. The Secretary in her sole discretion may extend the deadlines set forth in this Order. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

4. This proceeding is continued.

By the Commission,

Kathleen H. Burgess

Digitally Signed by Secretary
New York Public Service Commission

KATHLEEN H. BURGESS
Secretary

Exhibit No. NYT-16

PUBLIC VERSION
PRIVILEGED AND CONFIDENTIAL INFORMATION REMOVED
PURSUANT TO 18 C.F.R. § 388.112

Exhibit No. NYT-17

PUBLIC VERSION
PRIVILEGED AND CONFIDENTIAL INFORMATION REMOVED
PURSUANT TO 18 C.F.R. § 388.112