Indian Point Energy Center: Effects of the Implementation of Closed-Cycle Cooling on New York Emissions and Reliability

CO_2, SO_2 and NO_X emissions and reliability considerations under different IPEC outage scenarios and New York electric power sector input assumptions, for the period 2015-2025

Prepared for Riverkeeper

Prepared for Filing with the New York State Department of Environmental Conservation in the Matter of a Renewal and Modification of a State Pollutant Discharge Elimination System ("SPDES") Permit by Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, Permittee (DEC # 3-5522-0011/00004/ SPDES # NY-0004472)

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1. INTRODUCTION AND SUMMARY FINDINGS

1.1. Introduction

Background

The cooling water intake structures associated with the generation of electricity at the Indian Point Energy Center (IPEC) are subject to regulation by the New York Department of Environmental Conservation (NYSDEC) pursuant to Section 316(b) of the federal Clean Water Act (CWA) and 6 NYCRR § 704.5 via the State Pollutant Discharge Elimination System (SPDES) permit program. IPEC also requires a water quality certification (WQC) from NYSDEC pursuant to Section 401 of the CWA and 6 NYCRR § 608.9 in connection with the renewal of IPEC's Nuclear Regulatory Commission (NRC) operating licenses.

As pertinent to this report, NYSDEC issued a Draft SPDES permit renewal for IPEC on November 12, 2003, which required IPEC to reduce its cooling water intake capacity in order to minimize the entrainment of aquatic organisms and determined that closed cycle cooling represented the best technology available (BTA) to achieve the required reductions in entrainment and thereby minimize adverse environmental impacts associated with IPEC's cooling water withdrawals. Pending the construction of closed cycle cooling, the Draft SPDES also required interim compliance schedule measures which included the imposition of interim fish protection outages. NYSDEC has also since provided an offer of proof dated November 12, 2013 which addressed permanent outages (i.e., "Fish Protection Outage Days" or "protective outages") as a BTA alternative.[1]

In connection with the SPDES permit proceeding and CWA § 401 WQC proceeding, this report addresses the question of whether any adverse environmental effects in terms of air pollution from New York State electric power sector emissions and/or electric system reliability impacts may be associated with the NYSDEC's final closed-cycle cooling BTA alternative. That is, this report analyzes emissions and reliability impacts in relation to closed cycle cooling construction-related outages. The report includes assessment of emission and reliability effects if IPEC was fully out of service, a "bookend" analytical case. This report addresses electric power sector emissions effects and reliability impacts for anticipated IPEC closed cycle cooling construction outage scenarios, and focuses on assessing different system effects under different outage scenarios.

Energy owns and operates two pressurized water reactors (PWR), units 2 and 3 of the Indian Point Energy Center. Unit 1, the first reactor operated at Indian Point was retired from service in 1974. Unit 2

[1] NY DEC Department Staff Offer of Proof on Permanent Forced Outages/Seasonal Protective Outages, November 12, 2013. It is anticipated that seasonal fish protection outages may be required during periods which would include May through August of each year, a time period which also coincides with the period when electric demand reaches its annual peak in the New York and surrounding regions, usually occurring within the narrower window of July/August.

(1,024.5 MW, summer rated capacity) and unit 3 (1,044.2 MW, summer rated capacity)[2] have been operating since 1974 and 1976, respectively.

The electrical output from IPEC is directly interconnected to the New York electric power system, controlled by the New York Independent System Operator (NYISO, or NY ISO). The New York electric power system is directly and synchronously[3] interconnected to the New England, PJM, and Ontario electric power grid, and directly (though asynchronously)[4] to the Quebec power grid. Direct physical transfer of electric power occurs regularly among these larger entities, backed by financial arrangements between suppliers and customers in the region. Generally, electricity among these regions is physically shared according to the laws of physics and the fundamentals of electric power economics as they apply within and across the regions.

When any given unit is out of service, the rest of the generating supply resources on the grid respond and provide replacement power, generally according to short-run economic signals and in observance of the physical constraints across the grid, such as limited transmission transfer paths. At any given time, there is a single unit or a set of units that is "on the margin," i.e. being the resource that increases output or decreases output as demand increases or decreases. Over longer time periods, generating resources are constructed, generating resources are retired, transmission infrastructure is replenished (and often increased) and the mix of resources (and/or the fuel used by those resources) serving load gradually changes.

In the near term, if or when one or both IPEC units are out of service for any reason, replacement power is sourced from the aggregate of units available in New York and in the region according to short-run economics and transmission system transfer limitations. In the longer term, replacement power for an IPEC closed cycle cooling construction outage scenario will come from the collective set of existing and new resources connected to the grid, and will reflect any changes in ultimate demand that may occur due to changes in energy efficiency and/or demand response capability. In this report, we look at the interplay between requirements to reliably supply the region's load, and the set of power plants available to provide that supply. That interplay—which we model as electric power dispatch—leads to electric power sector output emissions. We also review the reliability implications associated with potential IPEC outages by examining NYISO reliability studies and recent New York State Public Service Commission (NYSPSC) inquiries into contingency plans for reliability in the event of IPEC retirement and potential transmission infrastructure investment to increase New York State's transmission capability.

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[2] NY ISO 2013 Gold Book, page 30.

[3] Synchronous interconnection essentially means all electrical generators in the defined region are in electrical synchronicity with each other; practically speaking, this means their operations must be coordinated by central controllers (such as the New York Independent System Operator, or NY ISO) to ensure a balance of power flow around the regions such that frequency and voltage are kept within defined ranges to ensure reliability, and transmission limits are respected.

[4] Quebec's interconnections with neighboring regions are through DC interties. This allows for more direct and scheduled control of power flows between its region and its trading partners compared to "free flowing ties" that accompany synchronously-interconnected systems.

We assess how replacement assets planned or considered would impact system emissions and system reliability under differeing IPEC closed cycle cooling construction outage scenarios.

Scope of Work

Riverkeeper engaged Synapse to conduct an electric power sector modeling analysis of the New York and adjoining electric power regions. This analysis focused on determining electric power output (MWh) and emissions (for CO_2, SO_X, and NO_X) that result under different closed cycle cooling construction scenarios where one or both units at IPEC are out of service for different periods of time. Synapse conducted this analysis for annual periods between 2015 and 2025, using the Ventyx PROSYM modeling tool, which was licensed for this specific analytical project. The PROSYM modeling tool allows unit-specific output and emissions to be determined for a given set of inputs, and those units are contained within specific zonal areas of New York and adjoining areas. Input assumptions can vary significantly in these types of analyses, and modeling multiple scenarios allows the user to gauge differential impacts for different closed cycle cooling construction scenarios tested. This report explains the rationale behind the assumption sets used, especially for load, energy efficiency, demand response, supply-side resources, and transmission topology, for each of the years modeled.

Synapse was also charged with conducting a review of the reliability circumstances that would surround IPEC closed cycle cooling construction outage scenarios. Synapse reviewed various New York Independent System Operator (NYISO) reports, NY PSC Orders and Rulings, New York utility filings, and related material to assess the status of reliability in the region in scenarios where one or both of the IPEC units were out of service for different periods of time for closed cycle cooling construction or even fully out of service in the alternative event of permanent closure. This assessment was limited to review of materials available primarily through the NYSPSC and the NYISO. In particular, the NYISO's 2012 Reliability Needs Assessment (RNA)[5] and the filings and orders in the NY PSC dockets on both the IPEC contingency plan and AC transmission upgrades informed our assessment.

Synapse's scope of work also includes appearing at the NYSDEC's SPDES and CWA § 401 WQC joint proceeding hearings and presenting expert testimony based on the analysis and findings in this emissions and reliability report.

1.2. Summary Findings

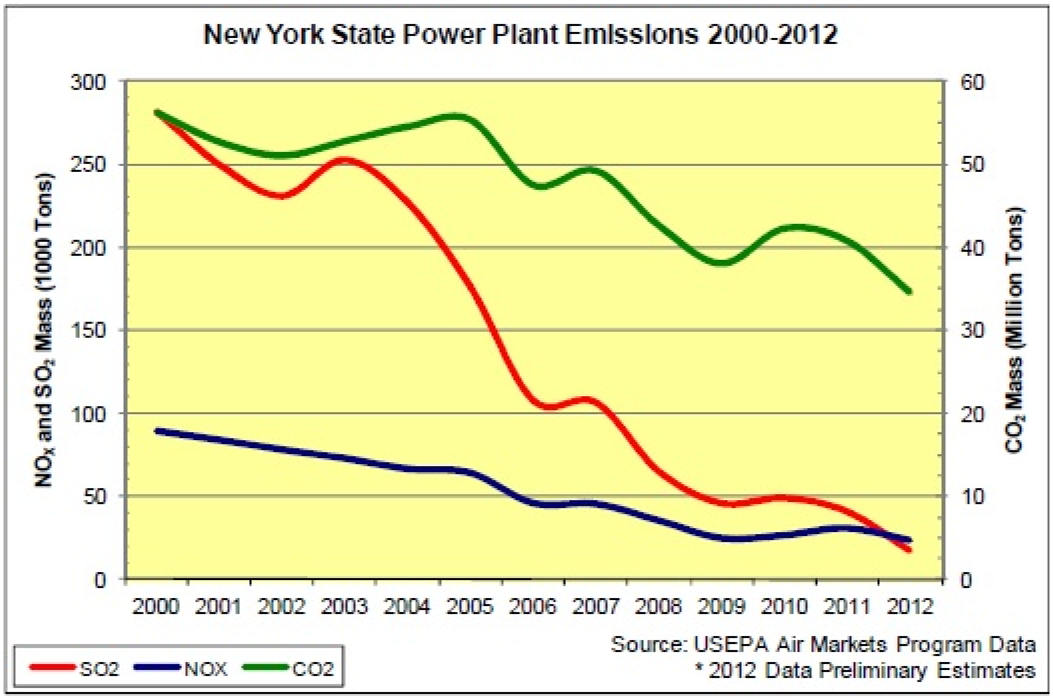
This section summarizes our emissions modeling and reliability assessment results.

[5] As noted in this report, the 2012 RNA predates the reliability contingency planning and transmission reinforcement planning work undertaken in the NYS PSC dockets. While the 2012 RNA informed out assessment, its sensitivity assessment of reliability in the absence of Indian Point was based on power flow model runs whose inputs are now in need of updating. To some extent, information filed by ConEd and NYPA in the reliability contingency planning docket at the NYS PSC addressed these issues.

Emissions Modeling

New York State has seen its electric power sector emissions decline considerably over the past decade. Electricity production from coal and oil-fired generation has declined, gas-fired generation has increased, efficiency of production has increased, and load increases have been mitigated by increasing levels of energy efficiency and the effects of economic recession. Figure 1 below, taken from a recent NYISO presentation, shows this decline.

Figure 1. New York State Electric Power Sector Emission Trends, 2000-2012



Source: NYISO presentation, "Environmental Regulations Set to Arrive," Peter Carney, Project Manager, Environmental Studies, New York Independent System Operator, NYSRC Installed Capacity Subcommittee, June 5, 2013. Available at http://www.nysrc.org/pdf/MeetingMaterial/ICSMeetingMaterial/ICS_Agenda148/Env%20impacts%206_%205_%202013%20final.pdf.

Synapse modeled future electric power sector emissions under 10 different scenarios of varying IPEC output and varying assumption sets for other key factors that influence emission levels. The next section of this report contains detailed information on this modeling process, which used the PROSYM production cost model, and the assumptions used. A high-level summary of our results is provided below.

Figures 2, 3, and 4 on the following pages show the projected pattern of carbon dioxide (CO_2), sulfur dioxide (SO_2), and Nitrogen Oxide (NO_X) emissions in New York State between 2015-2025 for the 10 scenarios analyzed.

The figures illustrate that even though a range of potential emission patterns from New York State electric generation exists over the period 2015-2025, the overall declining trend for NO_X and SO_2 emissions will likely continue, particularly with various scenarios where Indian Point is out of service for a closed cycle cooling retrofit or even in the event of permanent retirement. CO_2 emissions as modeled exhibit a flatter trend in the out years of our analysis (that is, post-2019), though we have not analyzed all reasonable longer-term resource scenarios, which could lead to ongoing CO_2 emission declines.

Figure 2 reflects anticipated CO_2 emissions under the scenarios analyzed, and contains a reference line indicating roughly what the New York State Regional Greenhouse Gas Initiative (RGGI) cap and trade budget will be for carbon dioxide emissions. As seen, the IPEC in-service “base line” emission level tracks, but is above, the RGGI benchmark levels.[6] With increases in energy efficiency up to New York State’s 15x15 target[7], the CO_2 emission are significantly lower, reflecting the compounding beneficial effects of energy efficiency installations. For a closed cycle cooling construction outage scenario with increases in energy efficiency, wind and solar photo voltaic (PV) (scenario 34), the CO_2 emission levels remain roughly on track with the RGGI benchmark levels. As expected, CO_2 emissions would be highest if no increases (beyond the baseline) in energy efficiency or deployment of renewable resources were seen, and IPEC was fully out-of-service for the entire time 2016-2025 timeframe (scenario 11). Also as expected, and as seen in our bookend scenario (scenario 41), the lowest level of CO_2 emissions was seen with incremental levels of energy efficiency, wind, solar PV, and IPEC in service.

Figure 3 shows the continuing decline in SO_2 emissions as coal and oil use for electric power generation continues to decline in New York. For a few scenarios of increased energy efficiency, high wind, and high solar PV installations, we assumed additional retirement of low-use coal-fired generation in New York. In these instances, SO_2 emission levels drop even further than the trends seen in the other scenarios.

Figure 4 shows the pattern of NO_X emissions in New York State. NO_X emissions decline as the share of energy from older gas-fired resources is replaced with energy from newer, lower-emitting combined cycle generation, from the new Champlain Hudson Power Express (presumed in service in 2018 in all scenarios), and from wind, solar, and energy efficiency resources in all scenarios—and NO_X emissions are even lower in the high energy efficiency, high wind, and high PV scenarios.

In all cases, transmission system improvements help improve the overall efficiency of the power system in New York State by allowing less expensive and, in many instances, lower-emitting resources (e.g., upstate wind power) to flow more easily (i.e., with reduced patterns of congestion).

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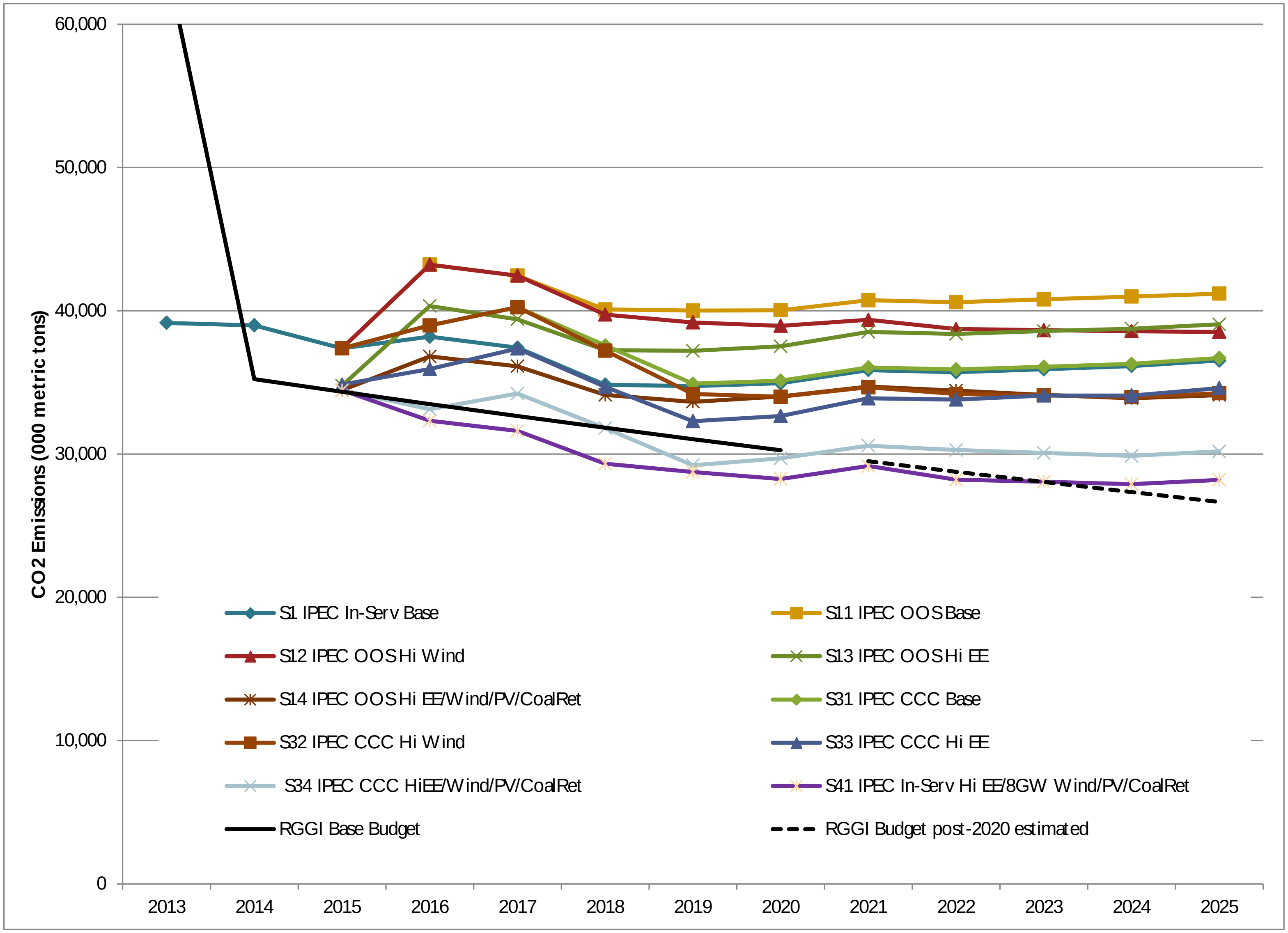
[6] The benchmark level included in this graph is the base budget for the adjusted RGGI CO_2 budget. New York Department of Environmental Conservation, State Environmental Quality Review Findings Statement, November 25, 2013, pages 1-2.

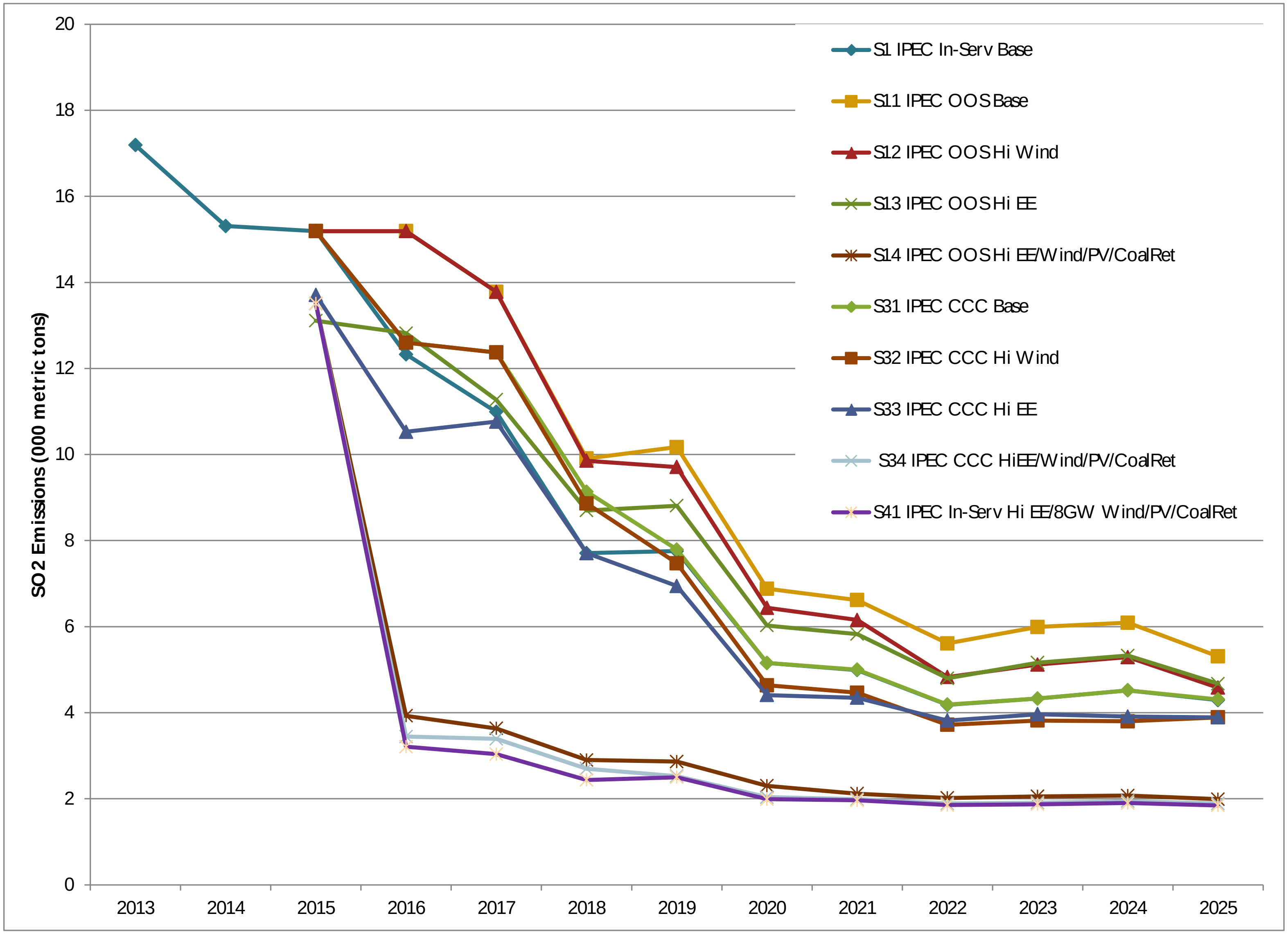
[7] New York State’s energy efficiency policy aims to achieve a 15 percent reduction in consumption by 2015 (2007 baseline).

Figure 2. CO_2 Emissions, New York State Electric Power Sector, 2015-2025, for 10 Modeled Scenarios



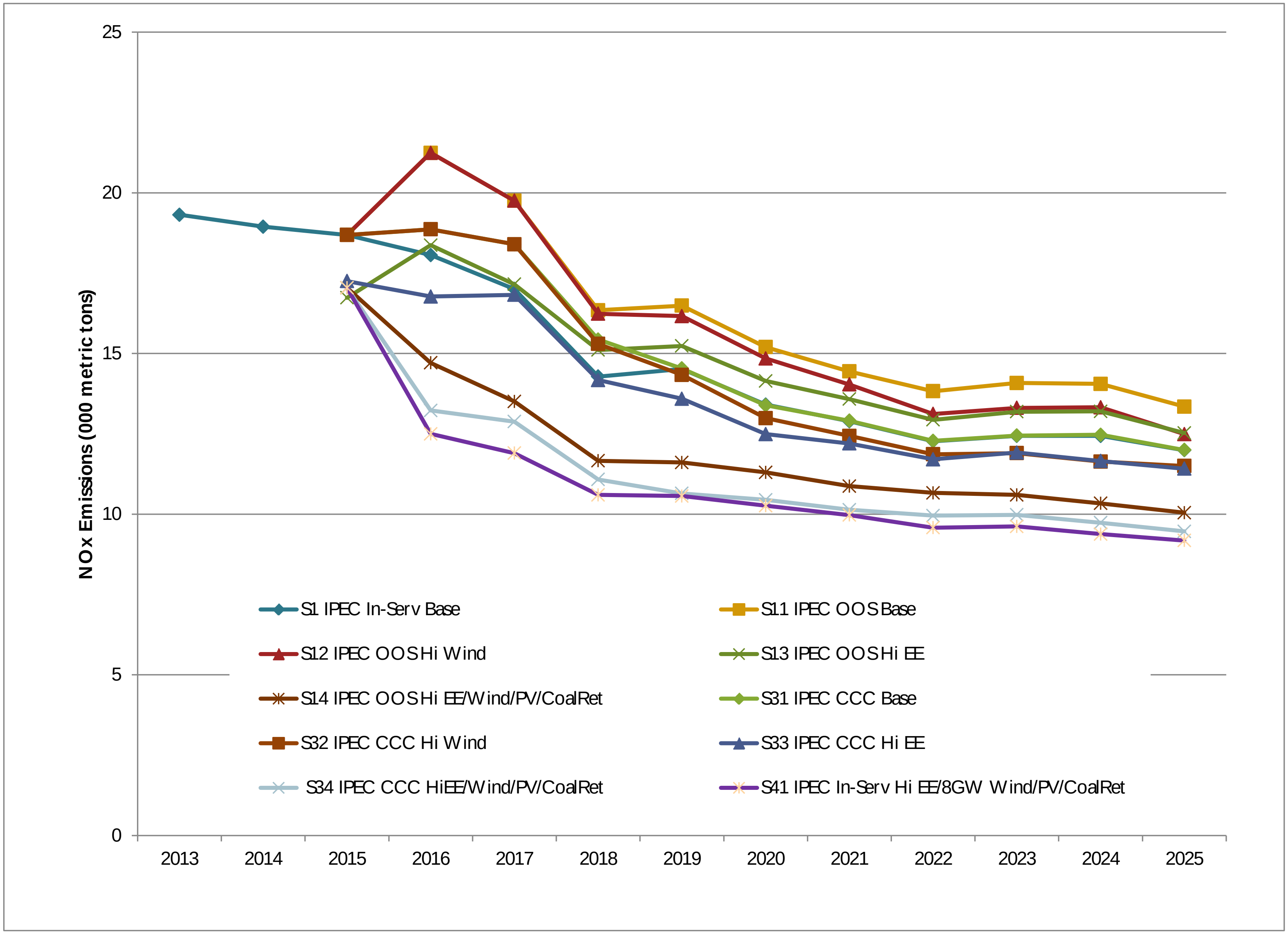
Source: Synapse PROSYM Modeling Analysis, 2014.

Figure 3. SO_2 Emissions, New York State Electric Power Sector, 2015-2025, for 10 Modeled Scenarios



Source: Synapse PROSYM Modeling Analysis, 2014.

Figure 4. NO_X Emissions, New York State Electric Power Sector, 2015-2025, for 10 Modeled Scenarios



Source: Synapse PROSYM Modeling Analysis, 2014.

We also estimated specific sources of "replacement power" for the IPEC outages, using a comparison between resource output during an IPEC in-service modeling scenario ("base" case scenario 1) and an examination of four other IPEC outage scenarios: two scenarios under which closed cycle cooling construction and installation occurs in two sequential years and IPEC is back online for the remaining years (scenarios 31 and 34, Table 1 below),[8] and two scenarios in which both IPEC units are fully out-of-service for all modeled years (scenarios 11 and 14, Table 2).[9] This comparative exercise allowed us to estimate replacement sources under different assumption sets. Notably, as seen in the results shown in these two tables, magnitude, location, and type of replacement resources vary considerably depending on the assumptions used for energy efficiency, wind, and solar PV installations.

It is important to note that, while we are aware that parasitic losses and thermal efficiency degradation will result from closed cycle cooling construction and installation, our focus was on system-wide trends, and the magnitude of such losses tends to be within forecast variation for net load, which range from the hundreds of MW (peak) into the 1,000s of MW (peak) for any given year for New York State load.[10] Thus for modeling purposes it was appropriate to ignore these effects on IPEC output.

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[8] As fully explained in the next section of this report, in the analysis of these analytic scenarios, we assumed a 60-day interim mitigation outage in 2016 for both units, a 60-day mitigation outage for unit 2 in 2017, and full-year construction outages (unit 3 in 2017, and unit 2 in 2018) for the IPEC units over the 2016-2018 time period. That assumption set leads to IPEC output reductions of 2.2 TWh (2016), 8.9 TWh (2017), and 7.3 TWh (2018). In both scenarios, both units are presumed back in service at full output in 2019 and beyond, the same as assumed in the base scenario 1.

While Synapse is aware that interim mitigation measures will be the subject of a different, later phase of the Indian Point hearing process , Synapse incorporated the 60-day outage assumption in order to reflect and model a more realistic and conservative scenario. Synapse is further aware that there will be a range of interim outage scenarios which may be longer or shorter than Synapse's 60-day assumption. We address the ramifications of the chosen assumption and the interpretation of the 2016 modeling output at appropriate places in the report. In addition, we note that Synapse will be providing a separate emissions and reliability analysis to specifically address interim and permanent fish protection outages in connection with the next phase of the hearings in this case, which will address a wider range of fish protection outage assumptions.

[9] Counsel for Riverkeeper has informed Synapse that Riverkeeper's position is that scenarios relating to shutdown of the facility in connection with NYSDEC April 2, 2010 Denial of Entergy's requested Clean Water Act Section 401 water quality certification is properly the subject of review under the National Environmental Policy Act (NEPA) in connection with the Entergy NRC license renewal proceeding rather than under the NYSDEC SEQRA review process. The consideration of fully out of service scenarios was, thus, considered only for analytical purposes and for the sake of completeness and generating a conservative analysis. That is, Synapse made this assumption as an analytical means to assess a "bookend" scenario.

[10] NY ISO 2013 "Gold Book", Table I-1, "NYCA Energy and Demand Forecasts with Statewide Energy Efficiency Impacts."

Table 1. Replacement Power Source Shares – Closed Cycle Cooling Construction Outage Scenarios 31 (Base EE[11], Wind, PV) and 34 (High EE[12], Wind, PV)

	Base EE, Wind, PV - Scen. 31			High EE, Wind, PV - Scen. 34		
	2016	**2017**	**2018**	**2016**	**2017**	**2018**
Imports (QB, Ont, NE, PJM)	31%	34%	25%	-56%	11%	-5%
Gas – J	20%	18%	23%	-46%	0%	-11%
Gas – F	15%	20%	25%	-26%	8%	-1%
Gas - GHI	17%	8%	18%	4%	4%	6%
Gas - CDE	5%	7%	5%	0%	4%	1%
Coal	3%	4%	8%	-204%	-46%	-38%
Gas – K	3%	4%	2%	-27%	-3%	-8%
Gas - AB	1%	2%	1%	3%	2%	1%
Wind				0%	0%	16%
EE				388%	100%	118%
PV				64%	21%	32%
Other	4%	1%	-7%	0%	0%	-10%
	100%	100%	100%	100%	100%	100%
Replacement TWh:	2.2	8.9	7.3	2.2	8.9	7.3

Source: Synapse PROSYM Modeling Analysis, 2014.

The left-hand side of Table 1 (scenario 31) indicates 2016-2018 replacement power is sourced primarily from a mix of imports and gas-fired resources in different locations, when no accommodation is made for potential increases in energy efficiency, wind, or solar resources above a base level of deployment. Increased imports from Quebec, Ontario, New England, and PJM comprise 31% of the 2016 replacement power, rising to 34% in 2017 and declining to 25% in 2018. New York City zone J[13] gas-fired resources make up the next largest share of replacement resources: 20% in 2016, and 23% by 2018. Remaining upstate zones (A through F) and downstate, lower Hudson Valley zones (G, H, and I) make up the remaining sources. For the near term, we have conservatively assumed that no additional wind resources (beyond those already assumed in-service through 2018) will be available through 2018 and, thus, they don't serve as replacement power resources in this comparison. As we will show, this is not

[11] "Base EE" is the baseline NYISO 2013 Gold Book peak load and energy forecast, and includes some amount of projected energy efficiency effects arising from New York utility's energy efficiency programs.
[12] "High EE" is the forecast that aligns with projections for peak load and energy consumption in 2015 that reflect the targets of New York's 15x15 energy efficiency portfolio standard (EEPS) policy.
[13] See Figure 5a for a representation of zones in New York. Zones AB are western NY; CDE are central/northern NY; F is the Capital region; GHI is lower Hudson Valley; J is New York City; and K is Long Island.

the case for later years (including the near-term year 2018) when replacement power effects with increased wind installations (relative to the base scenario 1) are examined.

The right-hand side of Table 1 (scenario 34) illustrates the effect that higher levels of energy efficiency, wind, and solar PV resources have on projected replacement power resources over time. The tables indicate that the presence of increased levels of energy efficiency, increased wind installations (in upstate zones), and increased solar PV installations (throughout New York State) significantly reduce the requirements for using fossil-fueled resources as replacement power relative to scenarios where deployment of incremental amounts of these resources is not assumed.

Energy efficiency effects dominate the statewide level of replacement power resources in 2016, and those resources in turn lead to declining amounts of fossil fuel use in all but zones A, B and G,H, I, relative to the baseline scenario, which does not contain this level of modeled energy efficiency. Under the analyzed scenario in which IPEC full unit outages are underway for closed cycle cooling installation in 2017 for Unit 3 and in 2018 for Unit 2, the replacement power amounts are larger, and energy efficiency's share declines; incremental gas usage is called for in all but zones J and K, and coal use is less than in the baseline scenario. In 2018, gas usage in downstate zones, coal usage, and imports are all lower than in the baseline scenario, and incremental wind power installations begin to impact the replacement power sources.

Table 2 below shows the replacement power resource shares in 2016, 2019, and 2025 for two analyzed scenarios in which both Indian Point units are fully out of service (scenarios 11 and 14). These results show the pattern of replacement resource need in the event that IPEC Units 2 and 3 are both fully out of service in each or any of these three given years, under base levels of energy efficiency, wind and PV installations (scenario 11) and under high levels of EE, wind and PV (scenario 14).

Table 2. Replacement Power Source Shares – IPEC Out-of-Service Scenarios 11 (Base) and 14 (High EE, Wind, PV)

	Base EE, Wind, PV - Scen. 11			High EE, Wind, PV - Scen. 14		
	2016	2019	2025	2016	2019	2025
Imports (QB, Ont, NE, PJM)	36%	24%	25%	25%	7%	-5%
Gas – J	18%	22%	26%	9%	6%	-8%
Gas – F	16%	25%	19%	13%	10%	-3%
Gas – GHI	7%	13%	16%	6%	8%	-1%
Gas – CDE	6%	5%	3%	6%	3%	-1%
Coal	6%	6%	3%	-29%	-18%	-10%
Gas – K	5%	2%	4%	2%	-3%	-3%
Gas – AB	2%	1%	0%	2%	1%	0%
Wind	0%	0%	0%	0%	15%	59%
EE				58%	53%	42%
PV				9%	18%	30%
Other	3%	2%	2%	0%	0%	0%
	100%	100%	100%	100%	100%	100%
Replacement TWh:	15.7	15.6	15.5	15.6	15.6	15.6

Source: Synapse PROSYM Modeling Analysis, 2014.

Scenario 11 gives no accommodation to increased levels of energy efficiency, wind, or solar PV resources. Thus, the only difference between scenario 11 and the base case scenario 1 is that IPEC is presumed fully out of service beginning in 2016. Imports, followed by New York City (Zone J) and then lower Hudson Valley (Zone GHI) and upstate (Zone A through F) and Long Island (Zone K) gas resources, make up the replacement power, along with upstate coal resources.

Scenario 14 shows the effect of higher levels of energy efficiency, wind, and solar PV on replacement resource shares over time. Notably, the deployment of these resources dramatically lessens the overall dependency on fossil fuel use, with fossil fuel use in all zones lower than (or equal to in zones A and B) that seen in the base scenario by 2025, and only marginally higher than the base scenario by 2019 (e.g., zone F gas use is higher in 2019 but just 10% of replacement power; zone J gas use is only 6% of replacement power in 2019; and gas use in zones G, H, I is 8% of replacement power).

Reliability Assessment

The New York electric power system can be operated reliably even in the absence of both of the Indian Point Energy Center units as of 2016 as long as 1) a number of anticipated electric system infrastructure improvements are completed across different parts of the New York electric power system, and 2) anticipated generation supply increases from either new merchant plants or existing resources (currently mothballed or requiring repair) come online. None of these improvements are located at the IPEC site. Completion of these improvements is currently planned or anticipated by June 1, 2016. The improvements need to be in place prior to the summer season following any IPEC outage, which is when New York sees its highest peak electrical load. Notably, under any scenario where at least one of the IPEC units remains available in the summer of 2016, reliable operation is also assured, since the reserve margin available to the New York system would be higher than with both units out of service.

These infrastructure improvements include new transmission system capacity known as the TOTS—Transmission Owner Transmission Solution–projects, new or returning-to-service generation capacity, and demand-side measures (energy efficiency, demand response, and combined heat and power (CHP) resources) that will lower the peak load seen on the Con Edison transmission system.[14] In combination, this portfolio of measures mitigates the reliability impacts that would otherwise be seen with the loss of such a significant amount of capacity as is represented by the Indian Point nuclear power plants. The combined effect of these projects is to relieve reliability concerns by some combination of increasing capacity resources, reducing load, or allowing existing capacity resources to be better utilized through the presence of additional transmission system infrastructure.

The NYS PSC Order accepting the IPEC Reliability Contingency Plan describes the impact of the improvements on the reliability of the system. A total capacity deficiency of up to 1,450 MW would exist on the New York system in 2016 with both IPEC units out of service if no improvements were made.[15] The Order approves the deployment of 185 MW of demand-side measures[16]—energy efficiency, demand response, and CHP measures—which lowers the need to roughly 1,265 MW. The NY PSC anticipates that the effect of the TOTS transmission improvements—also now approved by the Commission—will reduce the need by another 600 MW[17]. This rough estimate is validated by examination of materials provided by the New York utilities in the TOTS and AC transmission proceeding, and by New York transmission utilities response to the Energy Highway blueprint.[18] This lowers the original 1,450 MW need to roughly 665 MW.

Wholesale market supply resources are available to make up the remainder of reliability needs that exist after the implementation of transmission and demand-side measures. For example, the NY PSC Order notes the presence of 1,500 MW of existing merchant generation in the region that has been mothballed or is awaiting improved economic conditions or requires repair before a return to service.

[14] NYS PSC Order Accepting IPEC Reliability Contingency Plans, Establishing Cost Allocation and Recovery, and Denying Requests for Rehearing.

[15] While the IPEC units total roughly 2,069 MW (NY ISO 2013 Gold Book summer capability, page 30), sufficient reserve margin exists such that the IPEC units' capacity would not have to be fully replaced to ensure reliability in 2016.

[16] NYS PSC Order Accepting IPEC Reliability Contingency Plans, Establishing Cost Allocation and Recovery, and Denying Requests for Rehearing, at page 7 and 47.

[17] Id., at page 6.

[18] New York Transco, The Response to the New York State Energy Highway Request for Information, May 30, 2012, page 6. Available at http://www.nytransco.com/pdf/NYTO-Response-to-NY-Energy-Highway.pdf.

The NYISO testimony in September 2013 notes the presence of 1,900 MW of new resources in the generation interconnection queue with a commercial operation date in time for the summer of 2016.[19] The NYISO also explicitly noted the 552 MW of "mothballed" Astoria units, which are part of the 1,500 MW noted by the NY PSC. The planned implementation of a "new capacity zone" in the NYISO's installed capacity market for the Lower Hudson Valley is projected by the NYISO to increase the capacity revenues that would be available to resources locating in any of New York zones G, H, I or J.[20] These are the zones requiring the incremental capacity needed to ensure reliability, as indicated by the NYISO in the 2012 Reliability Need Assessment (RNA). [21]

Over the longer term, additional transmission system improvements under consideration by the NY PSC include reinforcement of other electrical paths in the Hudson River corridor. Those reinforcements, anticipated to be installed over the period 2018-2019, will allow increased transfer of upstate New York capacity to the downstate load centers. Additional merchant projects such as the anticipated 1,000 MW Champlain Hudson Power Express will also bolster downstate capacity and improve reliability.[22]

2. Production Cost and Emissions analysis

2.1. Overview

Synapse conducted a production cost analysis of the New York State electric power system over the period 2015–2025 to gauge CO_2, SO_2, and NO_X emissions from New York State fossil fuel generation under different scenarios of resource development and load for different patterns of IPEC availability. The primary purpose of this analysis was to develop a reasonable range of projected statewide (and zonal-based, reflecting the model's locational granularity) emissions under different IPEC outage scenarios. In particular, we analyzed scenarios in which Indian Point Units 2 and 3 are each sequentially offline for one year periods for the construction of closed cycle cooling, and scenarios in which both Indian Point units are offline concurrently each year from 2015-2025. These latter scenarios conservatively encompass any circumstance in which closed cycle cooling construction outages occur for

[19] NY ISO Vice President Thomas Rumsey, September 30, 2013 testimony before the New York Senate and Telecommunications committee.

[20] Presentations by the NYISO, New Capacity Zone Impact Analysis, January 30, 2013 and NCZ, Additional Impact Analysis, March 28, 2013.

[21] New York Independent System Operator, 2012 Reliability Needs Assessment, Final Report, September 18, 2012. Page 42. Available at http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/2012_RNA_Final_Report_9-18-12_PDF.pdf. The next RNA will be undertaken in 2014.

[22] The Champlain Hudson Power Express, a 1,000 MW transmission line interconnecting in Zone J (in Queens) is estimated to be in service by the beginning of 2018. We have assumed its deployment in all of our scenarios.

both units during any given year within the analyzed range. In this report we have examined emissions impacts from these such scenarios for representative years 2016, 2019, and 2025.

The analysis we conducted also allowed us to estimate the type, magnitude, and location of "replacement power" resources, effectively answering the question of where replacement power would come from if the IPEC units were out of service.

Critically, future patterns of load, energy efficiency deployment, and renewable resource development are uncertain but have material effects on emissions. Also, transmission path reinforcement and the associated increases in power flow limits affect statewide emissions—and especially any need for incremental downstate fossil-fired generation—by allowing increased transfer of energy from upstate to downstate. Based on current New York State policies and activities prescribing transmission reinforcement, we modeled planned improvements in critical transmission paths in our emissions analysis for all scenarios. We used two sets of loading assumptions—the 2013 Gold Book[23] baseline scenario and the New York State 15x15 energy efficiency scenario[24]—across our 14 scenarios. We used two different wind resource development assumptions: a baseline installation reflecting roughly 3.2 GW (3,174 MW) of installed wind across New York by 2025, and a scenario with roughly 6.2 GW (6,166 MW) of onshore wind. We used one scenario that tested up to 8 GW of wind (including offshore) to establish a relative lower bound or bookend on total emissions. We used the same set of fossil-fired additions in all scenarios, and we accelerated some coal unit retirement in the scenarios with increased levels of energy efficiency and wind. These assumptions are described in the following section.

PROSYM Production Cost Modeling

The Ventyx Market Analytics PROSYM model simulates the operation of the electric power system with a high degree of spatial and temporal resolution. It is an hourly dispatch model, with economic unit commitment and respective of zone-to-zone transmission path constraints. Appendix B contains descriptive detail of the PROSYM model. The model is an accepted and reliable tool of the scientific/energy economist community, and we note that the U.S. Environmental Protection Agency includes PROSYM among the models it considers available for quantifying air pollutant greenhouse gas (GHG) emission effects for clean energy initiatives.[25] We use the model to forecast the change in generation and emissions resulting from outages or removal of the IPEC units. The results will be dependent on a number of scenario assumptions outlined below, particularly assumptions related to load forecasts, unit additions, unit retirements, and transmission changes. There is some uncertainty as

[23] NY ISO 2013 Load & Capacity Data, "Gold Book".

[24] The 15x15 scenario envisions a 15% reduction in energy consumption by 2015 relative to 2007 baseline consumption. See e.g., New York Public Service Commission, Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, Order Establishing Energy Efficiency Portfolio Standard and Approving Programs, June 23, 2008.

[25] See, for example, an EPA background paper *Assessing the Multiple Benefits of Clean Energy*, Chapter 4.2.2, "Quantifying Air and GHG Emission Reductions from Clean Energy Measures." Table 4.2.4 (page 1) lists PROSYM among the "sophisticated" modeling tools available to gauge greenhouse gas emission effects from clean energy resources. Available at http://www.epa.gov/statelocalclimate/documents/pdf/background_paper_1-30-2012.pdf.

to how these changes could affect absolute levels of emissions or generation (in tons or MWh). We present "replacement resource" results as differentials (from a base scenario) rather than absolutes, as we are most interested in the change in these parameters resulting from outages (or in the extreme, permanent retirement) of the IPEC units, rather than the absolute value (though model results contain the absolute values).

We executed PROSYM model runs for the years 2015 through 2025 for 10 resource scenarios. We generally present the PROSYM results on an annual basis, though we list monthly price patterns and the model allows for extraction of data on a monthly or even an hourly basis. As will be seen in the following subsections explaining the basis for the assumptions we use, we relied upon NYISO 2013 Gold Book data, NYISO interconnection queue information, projections of potential wind capabilities per the NYISO "Growing Wind" wind generation study, and NYISO and NY PSC information on transmission. Gas price data used in the PROSYM model are reflective of the U.S. Energy Information Administration Annual Energy Outlook (AEO) price forecasts for gas in 2012 and estimated basis differentials (on a unit-specific basis) for delivery costs of natural gas to each unit. While near-term fluctuations in price are expected, current price estimates for natural gas in 2015 and beyond (the years we modeled) are similar to those-years' estimates from 2012.

2.2. Modeling Assumptions

Scenarios

Synapse defined 10 scenarios[26] to test the range of replacement power and emissions impacts that would arise under different input assumptions for an IPEC outage and for conditions around the state in the event of an outage. Table 3 contains the defined scenarios, including the key differences in variables for each of the assumptions.

[26] Synapse has executed more than 10 scenarios as part of our modeling process and has presented the results of 10 scenarios in this report as representative examples that provide a bounding and conservative analysis. Certain runs are also undertaken to initialize the model. This is part of the reason the scenario numbering system may seem to be somewhat random, or even confusing.

Table 3. PROSYM Scenarios Modeled

Scen. #	IPEC Status*	Load	Wind Additions	Coal Retirements	PV Additions	IPEC outage period
1	In-Serv	Base	Base (Low - 3GW)	Base	Base	Refueling only
31	2 Seq. Years	Base	Base (Low - 3GW)	Base	Base	Closed Cycle Cooling Unit 2: 60-day fish protection outage (FPO), 2016-2017; out of service (OOS), 2018; in-service 2019 Unit 3: 60-day FPO, 2016; OOS 2017; in–service 2018 Plus Spring refueling outages every 2 years (offsetting years, unit 2 and 3).
32	2 Seq. Years	Base	GrowWind 6 GW	Base	Base	
33	2 Seq. Years	Hi EE	Base (Low - 3GW)	Base	Base	
34	2 Seq. Years	Hi EE	GrowWind 6 GW	Other coal ret.	3 GW	
11	Fully OOS	Base	Base (Low - 3GW)	Base	Base	Fully OOS from 2016 through 2025
12	Fully OOS	Base	GrowWind 6 GW	Base	Base	Fully OOS from 2016 through 2025
13	Fully OOS	Hi EE	Base (Low - 3GW)	Base	Base	Fully OOS from 2016 through 2025
14	Fully OOS	Hi EE	GrowWind 6 GW	Other coal ret.	3 GW	Fully OOS from 2016 through 2025
41	In-Serv	Hi EE	GrowWind 8 GW	Other coal ret.	3 GW	Refueling only

Source: Synapse, 2014

** IPEC was modeled as fully in service ("In-Serv" in the table), fully out of service ("OOS") from 2016-2025, and out of service for sequential years in 2017 and 2018 for units 3 and 2 respectively following a 60-day fish protection outage (FPO) in year 2016 for both units and in 2017 for unit 2 ("2 Seq. Years")*

IPEC Outages

As seen in Table 3, three separate assumptions for the status of IPEC were modeled across our ten scenarios, which encompass permutations of IPEC outage, load (net of energy efficiency effects), and renewable resource deployment. First, we established baseline emissions by modeling IPEC fully in-service (with 24-month-interval refueling outages) from 2016-2025, in our scenario number 1.

In scenarios numbered 31 through 34, we modeled circumstances in which Indian Point Units 2 and 3 are each sequentially offline for one year periods for the construction of closed cycle cooling. For those outages, we conservatively assumed a one-year outage for each of the two units; and we assumed these outages would occur in consecutive years (unit 3 in 2017, unit 2 in 2018). These assumptions were made because we did not want to underestimate the emissions effect that would result in the event that closed-cycle cooling is installed for the units in this manner.

In particular, the Tetra Tech report indicates a 30-week (unit 2) and 35-week (unit 3) outages for the construction of closed cycle cooling ,[27] while the Enercon report estimated a 42-week duration concurrent outage for the construction of closed cycle cooling. We did not use these specific estimates for the sequential year-long closed cycle cooling construction outage scenario because we wanted to be conservative and not underestimate emissions effects if the plants were out of service for the construction . Importantly, these outage scenarios are also conservative since they assume that the construction outage will occur early within the range of years analyzed and in later years emissions would be progressively less as additional renewable energy sources are available and implemented.

As part of this outage sequence, based on material from the NYSDEC Offer of Proof on fish protective outages,[28] we assumed that mitigation would be required in 2016 even if preparations for closed-cycle cooling construction outages were not yet complete. We chose to draw our assumption from the 62-day fish protective outage for 2016 to establish a need for replacement power in that year. While Synapse is aware that interim mitigation measures will be the subject of a different, later phase of the Indian Point hearing process , Synapse incorporated the 60-day outage assumption in order to reflect and model a more realistic and conservative scenario of closed cycle cooling construction at Indian Point. Synapse is further aware that there will be a range of interim outage scenarios which may be longer or shorter than Synapse's 60-day assumption. We note that Synapse will be providing a separate emissions and reliability analysis to specifically address interim and permanent fish protection outages in connection with the next phase of the hearings in this case, which will address a wider range of fish protection outage assumptions.

Thus, these closed-cycle cooling construction outage scenarios encompass a need for replacement power of different amounts in 2016, 2017, and 2018. Our primary aim was to examine the pattern of emissions and the pattern of replacement power given this modeled scenario.

In scenarios 11 through 14, we modeled scenarios in which both IPEC units are fully out of service after 2015. These scenarios remove IPEC from the system for during 2016-2025 in order to gauge a bookend effect on emissions in New York State. Counsel for Riverkeeper has informed Synapse that Riverkeeper's position is that scenarios relating to shutdown of the facility in connection with NYSDEC April 2, 2010 Denial of Entergy's requested Clean Water Act Section 401 water quality certification is properly the subject of review under the National Environmental Policy Act (NEPA) in connection with the Entergy NRC license renewal proceeding rather than under the NYSDEC SEQRA review process. Accordingly, we undertook this scenario both as a "worst case"/bookend scenario, and also to help us to understand analytically how the system responds to the loss of a large energy-supplying facility. In our opinion, even though it is not required for the purpose of NYSDEC SEQRA review, from a purely analytical standpoint, it helps us to understand both modeling idiosyncrasies and New York State power system response.

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[27] Tetra Tech, at p. 23.

[28] NYSDEC Department Staff Offer of Proof on Permanent forced Outages/Seasonal Protective Outages, Table 3, page 15.

Importantly, the fully out of service scenarios which cover the full range of years 2016-2025 presents a conservative bounding assessment in relation to circumstances in which closed cycle cooling is constructed at Indian Point concurrently at both units during any given year between 2016-2025.

In addition, the data generated from these scenarios can be examined to determine the specific effects (relative to the baseline scenario 1) of year-long concurrent outages for the construction of closed cycle cooling construction. The effect of such concurrent construction outages can be seen for any of years 2016 through 2025. That is, these scenarios encompass potential circumstances in which concurrent outages of Indian Point Units 2 and 3 are taken for closed cycle cooling construction during any given year between 2016 and 2025. Under these scenarios we can see the emissions effects from concurrent outages of both generating units for any year-long period within the range of years examined. Notably, because this modeling assumes 52-week outages (rather than a 30, 35, or 42 week outage as suggested by other parties in this matter), the analysis, once again, provides a conservative outcome. In any event, it is worth noting that, although any incremental or decremental outage periods leads to incrementally lower or higher levels of replacement power, as is indicated by the specific result seen in our modeling for scenarios 31 through 34, the overall emission effect trends do not change considerably under minimally different outage periods for construction.

Our modeling did not involve any scenarios relating to emissions impacts resulting from the decreased generation output due to the actual operation a closed-cycle cooling system at Indian Point. We reviewed the information in the Tetra Tech and Enercon reports on the effects of parasitic losses and thermal efficiency degradation arising from operation of closed cycle cooling at Indian Point.[29] The anticipated maximum loss in net output, approximately 2-3%, can be characterized as negligible/"noise" in terms of statewide air emissions effects. That is, these effects are relatively small from the perspective of the entire New York State system, within forecast load variation. Thus, for the purpose of statewide emissions analysis, these effects can be ignored, as they would not have any meaningful impact on the results of our analysis.

Load and Demand-Side Assumptions

Two different loading scenarios were modeled across the 10 scenarios. For scenarios indicated as "Base" load, the 2013 Gold Book energy and peak demand values were used. For scenarios indicated as "High EE" or high energy efficiency, the New York State 15 x 15 loading scenario as contained in the 2012 RNA was used for energy and peak demand values. Table 4 below contains those assumptions for the New York control area as a whole. Appendix A contains this information by load zone for New York area. The PROSYM model aggregates the load in zones A and B; in zones C, D, and E; and in zones G, H, and I. The remaining zones F, J, and K are modeled as separate zones. For the out years (that is, 2023-2025) beyond which the 2013 Gold Book and the 2012 RNA did not have data, we extrapolated the average growth rate based on the growth rate trend between 2012 and 2022.

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[29] Tetra Tech, at section 2.3.4 (page 19-20) and section 2.6 (page 25).

Table 4. Annual Energy and Peak Load, 2015-2025

	Hi EE, RNA 15x15		Base Gold Book 2013	
	Energy	**Peak**	**Energy**	**Peak**
2012	163,653	32,822	163,653	33,295
2013	159,294	32,750	163,856	33,696
2014	158,073	32,549	164,652	33,914
2015	157,005	32,372	165,571	34,151
2016	158,180	32,556	166,804	34,345
2017	158,429	32,750	167,054	34,550
2018	159,050	33,051	167,703	34,868
2019	159,793	33,370	168,472	35,204
2020	160,804	33,675	169,499	35,526
2021	161,386	34,042	170,077	35,913
2022	162,174	34,342	170,915	36,230
2023	162,739	34,586	171,766	36,487
2024	162,970	34,818	172,439	36,732
2025	163,208	34,964	173,116	36,886

Source: NY ISO Gold Book, 2013; NY ISO 2012 Reliability Needs Assessment. Synapse extrapolation for 2023 – 2025.

Capacity Resources

Table 5 summarizes the resource capacity base included in the modeling. Our starting point was the updated (2013) Ventyx database of resources, which is based on the 2013 NYISO Gold Book resource database. We supplemented this in our scenario construction by adding gas, wind, solar, and planned Canadian hydro (via CHPE); and in some scenarios by retiring coal resources (Cayuga, Huntley).

Table 5. 2015 Base Case Capacity, MW, by Primary Fuel and NY Zone

Primary Fuel	AB (West)	CDE (Central North)	F (Capital)	GHI (SENY)	J (NYC)	K (LI)	Total
Nuclear	581	2,621	-	2,051	-	-	5,254
Hydro and Pumped Storage	2,804	1,303	1,541	80	-	-	5,728
Natural Gas	550	1,735	2,929	2,375	8,366	3,807	19,762
Petroleum - Oil and Kerosene	-	1,648	-	63	374	1,279	3,365
Coal	1,100	74	-	-	-	-	1,174
Demand Response	306	338	148	299	788	364	2,243
Wind	404	1,680	18	-	-	-	2,102
Other (sun, biomass, wood, refuse)	139	136	25	83	-	126	509
Total	5,885	9,535	4,661	4,951	9,528	5,577	40,136

Source: Synapse 2014 PROSYM Model Runs. Note: many natural gas and oil-fired units have the capability for burning multiple fuels.

Key Plant Additions and Retirements

In all of the scenarios we analyzed, two key downstate (i.e., PROSYM zone GHI) gas-fired additions were assumed in place—the CPV Valley combined cycle plant (678 MW, summer capacity rating) in 2016, and the Cricket Valley Energy Center combined cycle plant (1,020 MW, summary capacity rating) in 2018. We also added the 1,000 MW Champlain Hudson Power Express in 2018, represented as a NYC-connected resource. Additionally, repowering of the Astoria generation owned by NRG was assumed in stages, based on the current in-service dates listed in the NYISO generation queue: 250 MW for March of 2016, 250 MW for March of 2017, and 500 MW for June of 2018. In the later years of the analysis (post-2020), additional repowering of older gas-fired facilities is assumed to occur.

The scenarios assumed either a "base" level of wind, equal to roughly 3 GW of wind in New York State by 2025, or a "high" level of wind—6 GW, roughly equal to the quantity of wind analyzed in the "Growing Wind" wind integration report[30] if offshore wind were not in place. Lastly, we analyzed one scenario as a lowest emissions case bookend where a total of 8 GW of wind was assumed in place, 1.4 GW offshore plus 600 MW of additional wind beyond what was in place in the 6 GW onshore wind scenario. Base scenarios included relatively low levels of solar PV, and the "high PV" cases assumed a ramp up to roughly 3,000 MW (3 GW) of solar by 2025.

[30] NY ISO, Growing Wind, Final Report of the NY ISO 2010 Wind Generation Study, September 2010.

For some of the scenarios, Synapse assumed that the less economical of the remaining coal plants in New York—Cayuga and Huntley—would retire in 2016, leaving very little coal online, with coal energy provided almost solely by the AES/Somerset coal plant in western New York. Table 6 summarizes the resources changes made in these scenarios.

Table 6. Resource Additions and Retirements

Resource Addition or Retirement by Scenario	Quantity and Year
Base Scenarios (1,11, 13, 31, 33)	
Wind	Ramp up to 3,174 MW by 2025, CDE and AB
PV	18.6 MW utility scale by 2025; remaining behind-the-meter as part of net load.
Gas	CPV Valley, 678 MW (2016), Cricket Valley, 1,019 MW (2018), Astoria repower (1,040 in
Coal Retirement	Cayuga, Huntley - 2016
Other	Champlain Hudson Power Express, 2018
High Wind Only Scenarios (12, 32)	
Wind	Ramp up to 6,166 MW by 2025, Zones CDE and AB
PV	Same as Base
Gas	Same as Base
Coal Retirement	Same as Base
Other	Same as Base
High Wind, PV Scenarios (14, 34)	
Wind	Ramp up to 6,166 MW by 2025, Zones CDE and AB
PV	Ramp to 3,005 MW by 2025.
Gas	Same as Base
Coal Retirement	Base + all other coal except AES/Somerset
Other	Same as Base
Bookend – IPEC + High EE, Wind, PV (41)	
Same as Sc. 14, 34, plus Additional Wind	1.4 GW offshore wind, plus 200 MW additional onshore wind (LI for offshore; AB for onshore)

Source: Synapse, PROSYM mode inputs.

Transmission and Zones

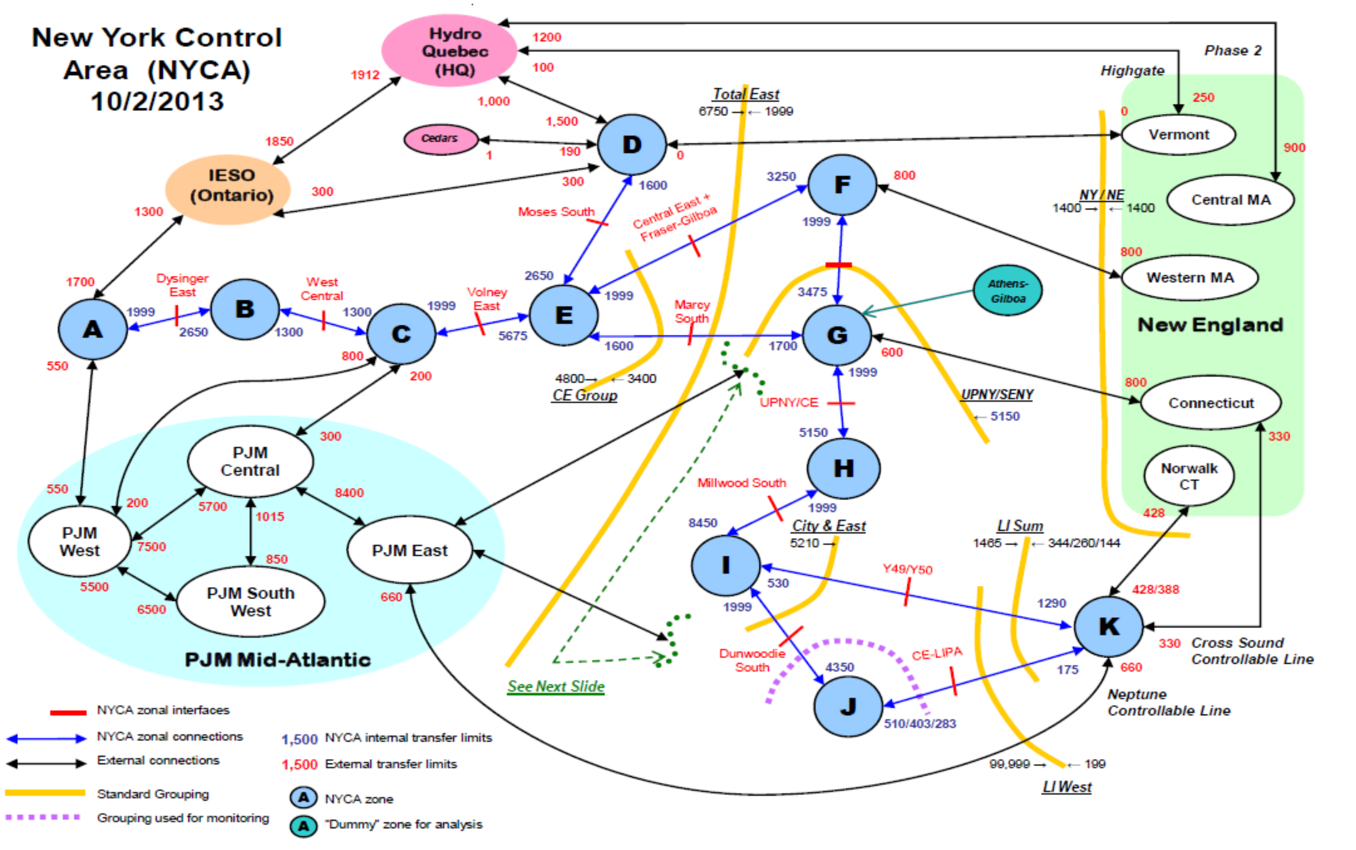
Figures 5a and 5b below are representations of electric power transmission, interfaces and load zones for New York State, taken from the New York Control Areas Installed Capacity Requirement Technical Study Report for the 2014/2015 period. They illustrate the major transmission paths, limits, designated NYISO zones and geography, and the interconnections between New York and its adjacent regions.

In general, energy flows across the New York transmission system in a predominately west-to-east direction in upstate New York, and then southeast and south towards the heavier loading zones of New York City, Long Island, and the lower Hudson Valley. The key transmission constraints historically have been those that limit flows across the "Total East," the "Central East," and the "UPNY-SENY" paths, as seen in the representation in Figure 5a. To the extent those major paths are reinforced, and the flow limits increased, increased levels of power generated in upstate New York can flow over the system to load areas in the southern portions of the state.

Figure 5a. 2014 Schematic Representation of New York Transmission – Interfaces and Load Zones

Figure A-12 2014 Transmission Representation

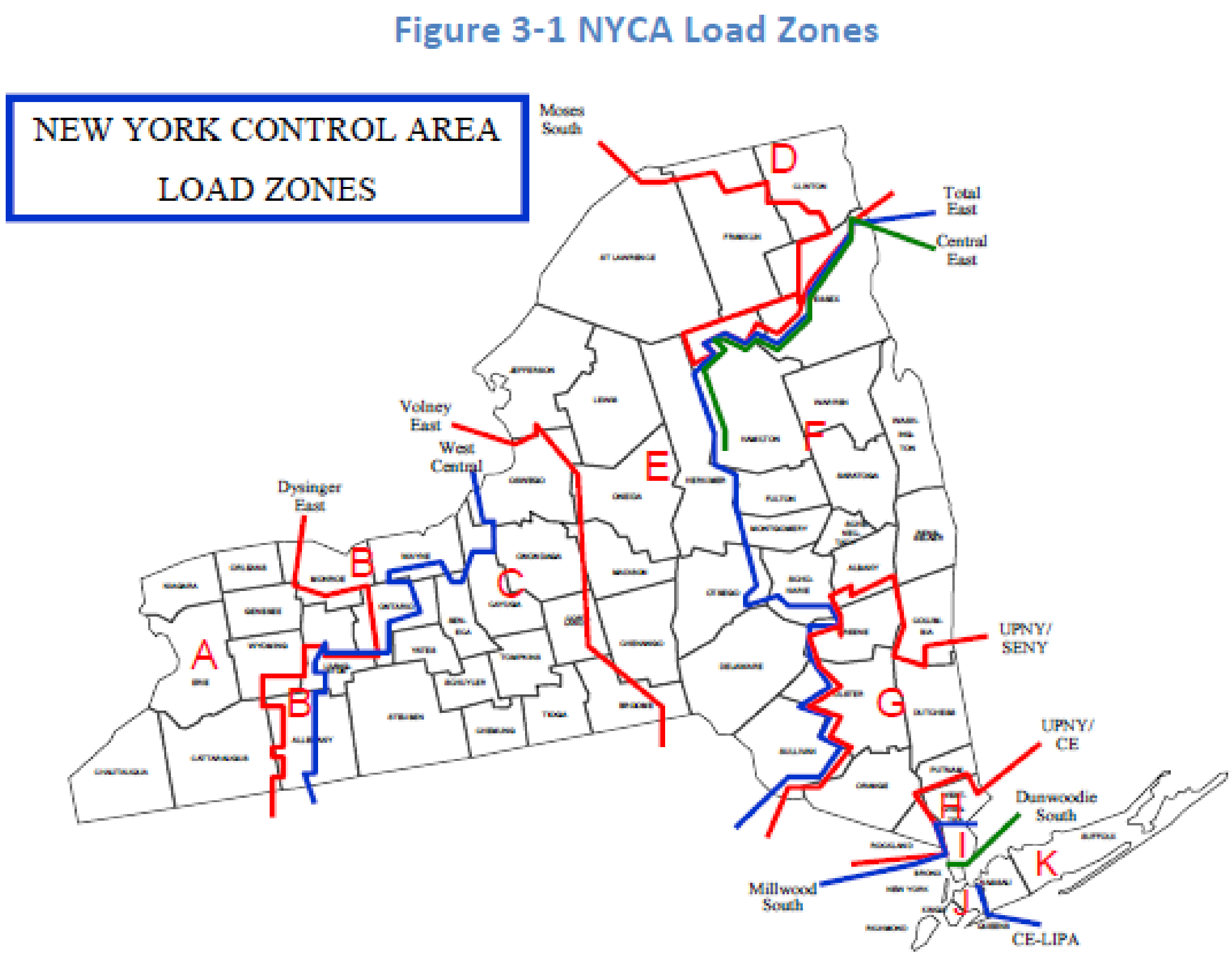
Transmission System Representation 2014 IRM Study - Summer Emergency Ratings (MW)



NYSRC-NYCA Installed Capacity Requirement for the Period May 2013 through April 2014 Page 37

Source: New York State Reliability Council, LLC, Installed Capacity Subcommittee, Appendices, New York Control Area Installed Capacity Requirement For the Period May 2014 to April 2015. Page 37. December 6, 2013.

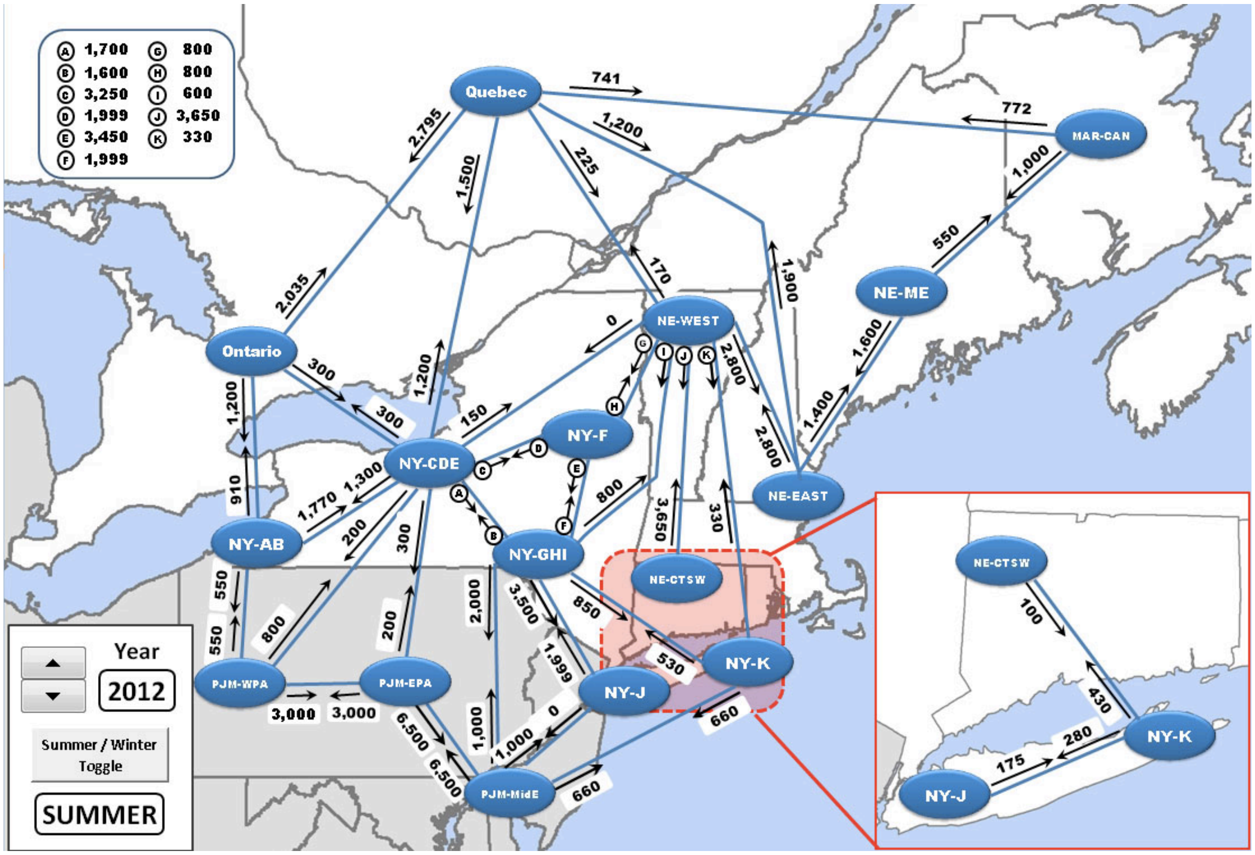
Figure 5b. 2014 Geographical Representation of New York Transmission – Interfaces and Load Zones



Source: New York State Reliability Council, LLC, Installed Capacity Subcommittee, Technical Study Report, New York Control Area Installed Capacity Requirement For the Period May 2014 to April 2015. Figure 3-1, NYCA Load Zones, Page 7. December 6, 2013.

Figure 6 below is an illustration of the baseline (circa 2012) New York zonal configuration used in the PROSYM model, along with the interconnected regions.

Figure 6. PROSYM Zonal Transmission Representation



Source: Market Analytics / Ventyx PROSYM Topology Illustration

Synapse updated a few key New York zone-to-zone transfer levels reflected in the PROSYM database to include increases estimated to occur with the installation of near-term transmission improvements (through 2016) due to the TOTS projects, and medium-term improvements (through 2019) arising from the AC transmission proceedings. We used the same transmission improvements across all scenarios. Table 7 below shows the zone-to-zone transfer levels prior to installation of the transmission upgrades, and after the upgrades are assumed to be in place, with the in-service year noted. Future year interzonal increases that may be implemented have not been included in our modeling. PROSYM uses these transfer levels to constrain its dispatch, essentially modeling the effect of transmission congestion across the zonal paths.

Table 7. Transmission Path Limit Representation in PROSYM Reflecting Projected Reinforcement Projects (MW)

From	To	2013	2014	2015	2016	2017	2018	2019	Increase, RRT + MSCC 2016	Increase, HVR + RRT + MSCC 2019
NY-CDE	NY-GHI	1700	1700	1700	2004	2004	2004	2202	304	502
NY-CDE	NY-F	3250	3250	3250	3310	3310	3310	3694	60	444
NY-F	NY-GHI	3450	3450	3450	3530	3530	3530	4468	80	1018
PJM-MidE	NY-GHI	1000	1000	1000	1000	1000	1000	1085		85
PJM-MidE	NY-J	1000	1000	1000	1000	1000	1000	1000		

Note: RRT = Ramapo to Rock Tavern 2nd 345 kV line. MSCC = Marcy South Series Compensation + Fraser to Coopers Corner reconductoring. HVR = Hudson Valley Reinforcement. CDE to GHI is assumed to be 33% of the UPNY-SENY path. F to GHI is assumed to be 67% of the UPNY-SENY path. CDE to F is assumed to be 100% of Central East path. CDE to GHI is assumed to be 25% of Total East path. CDE to F is assumed to be 47% of Total East path. PJM-MidE to GHI and PJMMidE to J are each assumed to be 14% of the Total East path. Source: Synapse PROSYM modeling, 2014, based on various sources of transfer increases for transmission projects.

Table 8 illustrates increases to transmission capacity across elements of the major paths in New York (as characterized in the PROSYM model) due to approved and planned transmission changes. The table reflects increases based on the following improvements:

- 2nd Ramapo to Rock Tavern 345 kV line, in service by June of 2016; it increases the UPNY-SENY thermal limits by 120 (normal) and 136 (emergency), the UPNY-ConEd thermal transfer limits by 1427 (normal rating) and 2784 (emergency rating), and increases the voltage transfer limits by 128 (UPNY-SENY) and 130 (UPNY-ConEd).[31] It increases the Total East limit by 59 (normal) and 66 (emergency).

- Marcy South Series Compensation and Fraser to Coopers Corner reconductoring (MSCC), also in service by June of 2016; it increases the Total East constraint path limit by 444 MW[32]; and

- NY Transco National Grid Hudson Valley Reinforcement (HVR) project between New York zones F and G, consisting of a third Leeds to Pleasant Valley 345 kV line.

These three improvements are interrelated. The NY Transco estimated the net effect of these improvements, along with additional improvements between Marcy and New Scotland and New Scotland and Leeds,[33] in a table they provided in response to the Energy Highway Blueprint.

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[31] Con Edison Company of New York, Additional Information on Transmission Owner Transmission Solution for Indian Point Contingency Plan, Second Ramapo to Rock Tavern 345 kV Line Project, May 20, 2013, pages 8-10. ConEd / NYPA Compliance Filing with respect to development of Indian Point Contingency Plan, Proceeding on Motion of the Commission To Review Generation Retirement Contingency Plan, Case 12-E-0503, Exhibit B, "Detailed Description of the Marcy South Series Compensation and Fraser to Coopers Corner Reconductoring Project, page 10. Filed February 1, 2013.

[32] Final Report of the System Impact Study for the MSSC project, NYISO queue # 380. Submission of Comparable Information Pursuant to the April 19, 2013 Public Service Commission Order, Case 12-E-0503, Marcy South Series Compensation and Fraser to Coopers Corner Reconductoring Project, May 20, 2013.

Table 8. NY Transco Estimate of Thermal Transfer Path Increased from TOTS and AC Proceeding Projects

NYISO Transmission Interface	Basecase, MW	New Limit, MW	Net Increase, MW
UPNY – SENY	5942	7462	1520
UPNY – ConEd	6297	8674	2377
Central East	3151	3595	444
Total East	4640	5169	529
Moses South	1518	3672	2154

Source: NY Transco, "Increase in Upstate to Downstate Normal Transfer Capability Resulting from the Projects." Response to Energy Highway Blueprint, page 6.

The first two improvements from the list above (Ramapo to Rock Tavern 2nd 345 kV line, and MSSC) have been approved by the New York PSC in the IPEC Contingency Plan docket.[34] Various competing improvements are under consideration in the AC transmission proceeding. For the purposes of establishing baseline transfer increases for all cases modeled, we used the New York Transco Response NY Transco response to energy highway blueprint (page 6) to estimate the values of transfer limit increases for the UPNY/SENY interface. We computed increases for each of the PROSYM paths as shown in Table 9 above to model the effect of these improvements.

2.3. Modeling Results

Our results show a reasonable range of emission impacts over time that could be expected under different IPEC outage scenarios. We do note that we have not tested the full set of combinations of forward-looking resource development; in particular, we have not included future offshore wind installations with any IPEC outage scenarios,[35] nor have we increased energy efficiency development beyond the 15x15 scenario envisioned by New York State.[36] We have added the Champlain Hudson Power Express (in 2018) but have not assumed any further expansion of imports from Quebec or

[33] See NY Transco response to Energy Highway Blueprint, at page 6. NY Transco describes the complementary improvements (to the 3rd Leeds to Pleasant Valley line) needed to fully reinforce the Central East and the Total East path from Marcy to the south and east.

[34] NYS PSC Case 12-E-0503, November 4, 2013 Order.

[35] As noted, we did run a single scenario with roughly 8 GW of wind (including 1.4 GW of offshore wind) and with IPEC in-service, serving as a relative lower bound on CO_2 emissions across all of the scenarios we tested.

[36] The 15x15 scenario envisions a 15% reduction in energy consumption by 2015 relative to 2007 baseline consumption. See e.g., New York Public Service Commission, Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, Order Establishing Energy Efficiency Portfolio Standard and Approving Programs, June 23, 2008.

Ontario.[37] We have limited upstate onshore wind development to roughly 6 GW by 2025, in line with the maximum non-offshore-wind scenario tested in the "Growing Wind" report[38] but not reflective of likely technical maximum penetrations of wind power.[39] We have tested the effects of installation of a total of 3 GW of solar PV by 2025,[40] and while this reflects an aggressive level of growth, it is not unreasonable to envision even larger penetrations of this resource over time.[41] Thus, from the perspective of longer-range emissions targets for New York, our resource development assumptions are conservative; i.e., lower levels of emissions could be seen with more aggressive renewable resource and energy efficiency development, and/or imports of Canadian renewable resources.

Generation Supply—2012 Actual and Base Scenario

Table 9 shows the 2012 annual generation (GWh) and share (%) in New York by fuel, and estimated import levels for each of Quebec, Ontario, New England, and PJM sources.

[37] Our analysis shows reductions in imports over the historical paths into upstate New York from Ontario and Quebec (i.e., into zones A and D) in the later years (post-2020) in most scenarios. While this likely reflects in part the effect of more wind coming online in the upstate zones, utilizing available transmission, resource limitations prevented further analysis of Ontario and Quebec systems to determine whether higher levels of future year imports represent reasonable scenarios for analysis.

[38] NYISO, "Growing Wind: Final Report of the NYISO 2010 Wind Generation Study," September 2010.

[39] For example, in our 6 GW wind scenarios with 15x15 efficiency reflected in the annual energy demand, wind represents roughly an 11% statewide energy share in 2025 (18 TWh /163 TWh). Wind penetration amounts greater than 11% of annual energy consumption can generally be accommodated.

[40] Based on New York public policy aims. See, for example, the Petition of NYSERDA, before the New York Public Service Commission, Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard, Case 03-E-0188, Petition, NY-SUN 2016-2023 Funding Considerations and Other Program Implementation Considerations, page 2.

[41] Solar photovoltaic costs have been declining precipitously, making their installation more economic. See for example, *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*, July 2013, by Galen Barbose, Naïm Darghouth, Samantha Weaver and Ryan Wiser. Available at http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.

Table 9. 2012 New York Energy Balance by Fuel or Source

Resource Fuel	2012 GWh	2012 share
Hydro & Pumped Storage	25,303	15.5%
Nuclear	40,817	25.1%
Coal	4,281	2.6%
Oil #2/Oil #6/Kerosene	200	0.1%
Wind	3,060	1.9%
Other	2,998	1.8%
Estimated Net Imports (QC, Ont, PJM, NE)	23,705	14.6%
Quebec	10,184	6.3%
Ontario	5,241	3.2%
PJM	7,107	4.4%
NE	1,173	0.7%
Nat Gas Zones A-I	24,854	15.3%
Nat Gas Zone J (NYC)	26,663	16.4%
Nat Gas Zone K (LI)	10,961	6.7%
Total Consumption	162,842	100.0%
New York In-State Generation*	139,137	85.4%

**includes Linden Cogen and Bayonne Energy Center. Source: 2013 Gold Book, Actual 2012 generation for New York generation. Total consumption from NYISO Power Trends 2013, page 18. Total imports estimated from balance of New York generation and total consumption, source of imports estimated from 2012 State of the Market Report.*[42] *Dual-fuel sources estimated to have consumed gas in 2012, based on economics.*

Table 10 below shows Synapse's base scenario (1) generation for 2015-2019, and for 2025, by fuel source and disaggregated by PROSYM zone for natural gas sources.

[42] The 2012 State of the Market Report contains additional information on imports into New York from the surrounding regions during 2012. It contains average MW flow information as scheduled, but excludes the effects of loop flows, and does not contain estimates of the actual total energy (GWH) amounts from each adjacent area.

Table 10. Synapse Base Scenario (1) Modeled Generation (TWh), 2015-2019, 2025, and Actual 2012

<table>
<tr><th></th><th>2012 Actual</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2025</th></tr>
<tr><td>Hydro & PS</td><td>25.3</td><td>27.3</td><td>27.3</td><td>27.4</td><td>27.2</td><td>27.2</td><td>27.3</td></tr>
<tr><td>Nuclear</td><td>40.8</td><td>40.0</td><td>39.5</td><td>39.9</td><td>39.1</td><td>40.3</td><td>40.3</td></tr>
<tr><td>Coal</td><td>4.3</td><td>5.4</td><td>5.0</td><td>4.6</td><td>3.2</td><td>3.2</td><td>1.8</td></tr>
<tr><td>Oil/Kerosene</td><td>0.2</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td></tr>
<tr><td>Wind</td><td>3.1</td><td>5.9</td><td>5.9</td><td>6.1</td><td>6.1</td><td>6.1</td><td>9.2</td></tr>
<tr><td>Other</td><td>3.0</td><td>3.1</td><td>3.3</td><td>3.3</td><td>3.2</td><td>3.3</td><td>3.5</td></tr>
<tr><td>Imports</td><td>23.7</td><td>18.0</td><td>16.4</td><td>16.4</td><td>20.1</td><td>20.1</td><td>12.6</td></tr>
<tr><td>Nat Gas All Zones</td><td>62.5</td><td>66.5</td><td>70.5</td><td>70.5</td><td>69.9</td><td>69.3</td><td>80.3</td></tr>
<tr><td>NG - AB</td><td rowspan="4">24.9</td><td>1.9</td><td>1.9</td><td>1.8</td><td>1.6</td><td>1.6</td><td>1.5</td></tr>
<tr><td>NG - CDE</td><td>9.4</td><td>9.2</td><td>8.9</td><td>8.1</td><td>8.1</td><td>7.4</td></tr>
<tr><td>NG - F</td><td>17.8</td><td>17.5</td><td>16.3</td><td>12.5</td><td>12.0</td><td>9.4</td></tr>
<tr><td>NG - GHI</td><td>0.7</td><td>4.3</td><td>5.9</td><td>12.6</td><td>12.5</td><td>16.5</td></tr>
<tr><td>NG - J</td><td>26.7</td><td>25.0</td><td>26.0</td><td>26.5</td><td>24.6</td><td>24.5</td><td>28.9</td></tr>
<tr><td>NG - K</td><td>11.0</td><td>11.6</td><td>11.6</td><td>11.1</td><td>10.5</td><td>10.6</td><td>16.5</td></tr>
<tr><td>Total</td><td>162.8</td><td>166.1</td><td>167.9</td><td>168.2</td><td>168.8</td><td>169.5</td><td>174.9</td></tr>
</table>

Source: 2015-2019, 2025: Synapse 2014 PROSYM scenario 1. 2012 Actual from Table 9 above.

The base scenario contains roughly constant annual output for nuclear, hydro, and pumped storage resources in New York. It shows an increase in coal use in 2015 relative to actual coal plant output in 2012, reflecting underlying load growth and the economics of coal vs. gas as a marginal fuel, but in later years, coal use declines. Wind power doubles its output by later in the decade relative to actual production in 2012, and triples its output by 2025—this arises from our base scenario assumption that New York will have an installed wind capacity of roughly 3.1 GW by 2025. Oil use remains extremely low; for example, the highest year of oil consumption in our base case is 22 GWh, much less than one-tenth of one percent of the State's electricity consumption. Our 2012 actual values recognize dual-fuel units but assume gas use in that year due to economics. Our modeling estimates gas use for dual-fuel units in general because of economics.

Replacement Power Sources Under Different Outage Scenarios

The following two tables (Tables 11 and 12) contain summary results estimating average annual replacement power source shares under four different scenarios: two outage scenarios reflecting sequential year-long outages at Indian Point Units 3 and 2 in 2017 and 2018, respectively following a 60-day fish protection outage in 2016 for both units and a 60-day outage in 2017 for unit 2 (scenarios 31 and 34), and two scenarios reflecting both units of IPEC being fully out-of-service from 2016-2025 (scenarios 11 and 14). For each of these scenarios we use base levels and high levels of EE, wind and solar PV.

As noted, for each outage scenario, we show replacement power for base level resource assumptions (scenario 11 and scenario 31) and for high levels of energy efficiency, wind, and solar PV deployment (scenario 14 and scenario 34). In the sequential year-long outage scenarios, [43] we show replacement power requirements for three years, 2016 through 2018 (both units are modeled back online in 2019).

Table 11. Replacement Power Source Shares - Year-Long Sequential Outage Scenarios 31 (Base) and 34 (High EE, Wind, PV)

	Base EE, Wind, PV - Scen. 31			High EE, Wind, PV - Scen. 34		
	2016	**2017**	**2018**	**2016**	**2017**	**2018**
Imports (QB, Ont, NE, PJM)	31%	34%	25%	-56%	11%	-5%
Gas – J	20%	18%	23%	-46%	0%	-11%
Gas – F	15%	20%	25%	-26%	8%	-1%
Gas - GHI	17%	8%	18%	4%	4%	6%
Gas - CDE	5%	7%	5%	0%	4%	1%
Coal	3%	4%	8%	-204%	-46%	-38%
Gas – K	3%	4%	2%	-27%	-3%	-8%
Gas - AB	1%	2%	1%	3%	2%	1%
Wind				0%	0%	16%
EE				388%	100%	118%
PV				64%	21%	32%
Other	4%	1%	-7%	0%	0%	-10%
	100%	100%	100%	100%	100%	100%
Replacement TWh:	2.2	8.9	7.3	2.2	8.9	7.3

Source: Synapse PROSYM Modeling Analysis, 2014.

As seen, in the base scenario (31) the proportion of replacement power varies as replacement power need changes (from 2.2 TWh in 2016 to 8.9 and 7.3 TWh in 2017 and 2018) and reflecting transmission

[43] Under these scenarios, Synapse estimated a 60-day interim mitigation outage for 2016 for both units and for unit 2 in 2017. Synapse understands that a range of interim measures, some lengthier, some shorter, will be considered during separate, future hearings in this matter. Thus, while we selected a 60-day interim mitigation outage assumption in order to make out assessment of sequential one-year closed-cycle cooling construction outages scenarios more realistic and conservative in nature, our assumption does not necessarily reflect the most conservative estimate for potential replacement power. In any event, while any incremental or decremental outage periods leads to lower or higher levels of replacement power, overall emission effect trends do not change considerably under minimally different outage periods. We note that Synapse will be providing a separate, complete analysis in relation to interim mitigation outages and permanent fish protection outages for future portions of the Indian Point proceedings, which will analyze the full range of potential outage scenarios.

and gas-fired resource deployment (e.g., repowered Astoria units online in 2018; Cricket Valley (zone GHI) online in 2018; upstate-to-downstate path limit increase in 2018).

In the high energy efficiency, wind, and PV deployment scenario (34), statewide efficiency, wind, and PV more than replace IPEC's reduced output, but increased gas use is still required in some zones reflecting locational requirements, which the model respects. Coal use is much lower, and notably gas use in zone J also declines in 2016 and in 2018, remaining about the same in 2017. These results illustrate the interdependence of resource deployment, especially energy efficiency gains and transmission improvements when gauging sources of replacement power. With lower load (a result of energy efficiency) and increased sources of zero-fuel-cost energy (wind, PV), the remaining mix of marginal units (imports and in-state gas generation) is economically "redispatched" in the model. As new units come online (e.g., Astoria repower, Cricket Valley) they not only provide replacement power but displace output from older, higher-heat-rate gas-fired units. Thus, use of a full economic dispatch model reflecting these interacting effects is required to properly gauge resulting locational and source impacts under outage scenarios.

In the IPEC fully out-of-service from 2016-2025 scenarios (scenarios 11 and 14), presented in the table below, replacement power amounts are higher than those seen in the scenarios in which there are sequential year-long outages at Indian Point Units 3 and 2 in 2017 and 2016, respectively following a 60-day fish protection outage in 2016 (scenarios 31 and 34), which reflect the full output of both IPEC units for all other years. We show these results for 2016, 2019, and 2025, to convey immediate impacts and longer-term trends.[44]

[44] We also note that the impact shown for the out-of-service scenarios could be used to estimate impacts for any given single year for a closed cycle cooling construction outage scenario involving a dual-unit outage occurring conservatively for one year. Importantly though, the results presented, which focus on the fully out of service scenario for the full range of years 2016-2025 presents a conservative bounding assessment in relation to circumstances in which closed cycle cooling is constructed at Indian Point concurrently at both units during any given year between 2016-2025.

Table 12. Replacement Power Source Shares – IPEC Out-of-Service Scenarios 11 (Base) and 14 (High EE, Wind, PV)

	Base EE, Wind, PV - Scen. 11			High EE, Wind, PV - Scen. 14		
	2016	2019	2025	2016	2019	2025
Imports (QB, Ont, NE, PJM)	36%	24%	25%	25%	7%	-5%
Gas – J	18%	22%	26%	9%	6%	-8%
Gas – F	16%	25%	19%	13%	10%	-3%
Gas – GHI	7%	13%	16%	6%	8%	-1%
Gas – CDE	6%	5%	3%	6%	3%	-1%
Coal	6%	6%	3%	-29%	-18%	-10%
Gas – K	5%	2%	4%	2%	-3%	-3%
Gas – AB	2%	1%	0%	2%	1%	0%
Wind	0%	0%	0%	0%	15%	59%
EE				58%	53%	42%
PV				9%	18%	30%
Other	3%	2%	2%	0%	0%	0%
	100%	100%	100%	100%	100%	100%
Replacement TWh:	15.7	15.6	15.5	15.6	15.6	15.6

Source: Synapse PROSYM Modeling Analysis, 2014.

The rough proportions of replacement power are not too different in the base case (11, no incremental energy efficiency, wind, or PV) from that seen in the two year-long sequential outage base scenario (31), though the absolute levels are much higher. Notably, in the high energy efficiency, wind and solar PV scenario (14) the demand-side and renewable resources more than fully displace the entirety of the IPEC unit output by the end of the modeled period (2025), and even by 2019 these resources displace more than 85% of the IPEC loss. The net effect, including coal resource output reductions, is a modest increase in gas-fired generation in 2016 and 2019 to round out replacement power needs.

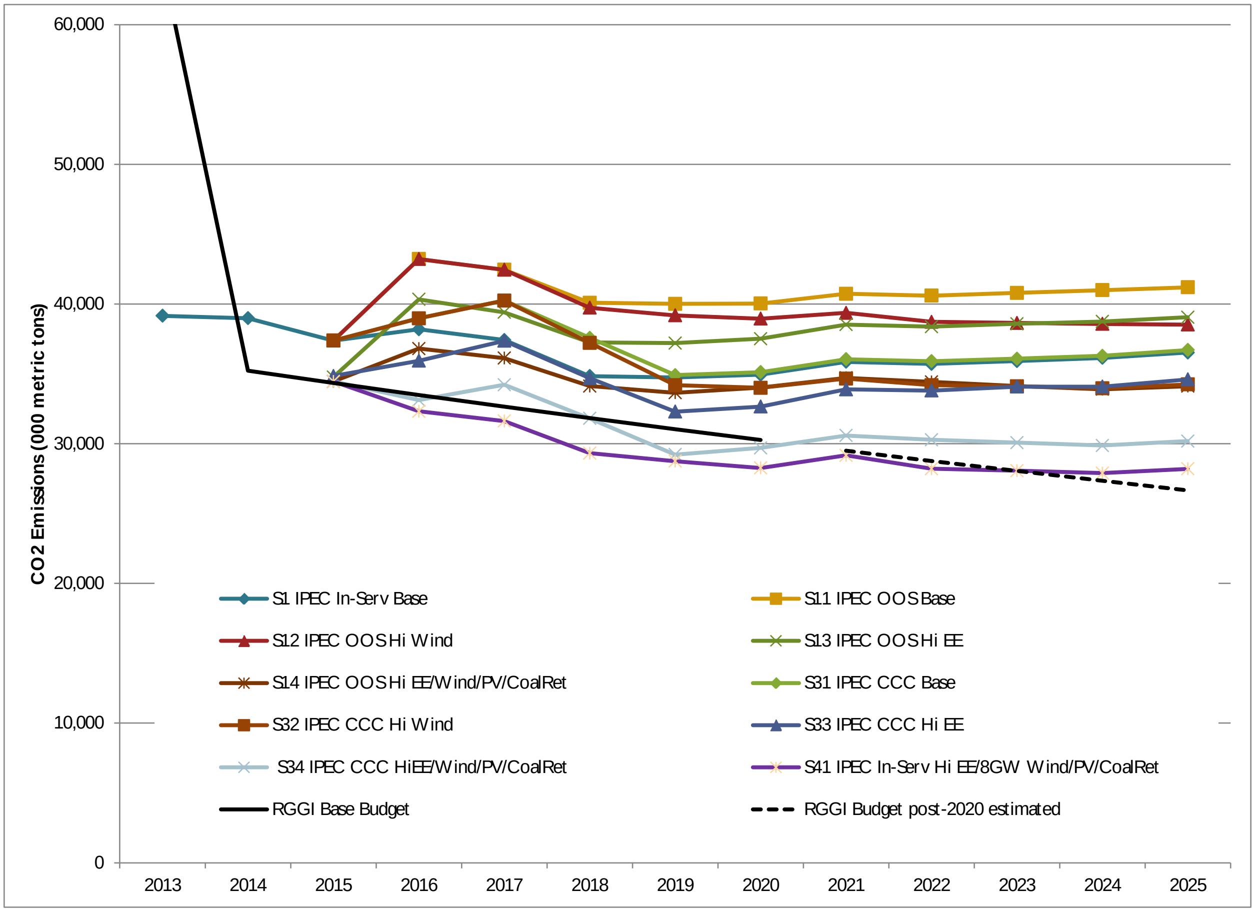
New York State Aggregate Emissions across Scenarios

Figures 7 through 9 show projected CO_2, SO_2 and NO_X emissions across New York State between 2015 and 2025 for 10 scenarios, based on our modeling results. Data tables are included below the figures.

The CO_2 emission pattern shows that continuing declines in CO_2 emissions will only be seen if steps are taken to deploy more energy efficiency and renewables than is represented in the base scenario, irrespective of whether or not the IPEC units remain in service. We note that further declines are possible if energy efficiency deployment beyond the "15 x 15" modeled (in the high energy efficiency scenarios) is undertaken, and if increased levels of wind deployment occur—in particular including more offshore wind (which we only model in one bookend scenario, shown as the lowest CO_2 emission line in the graph). As we note, while we modeled an array of scenarios to test emission (and replacement power) effects under different IPEC outages, we did not test all feasible resource deployment strategies.

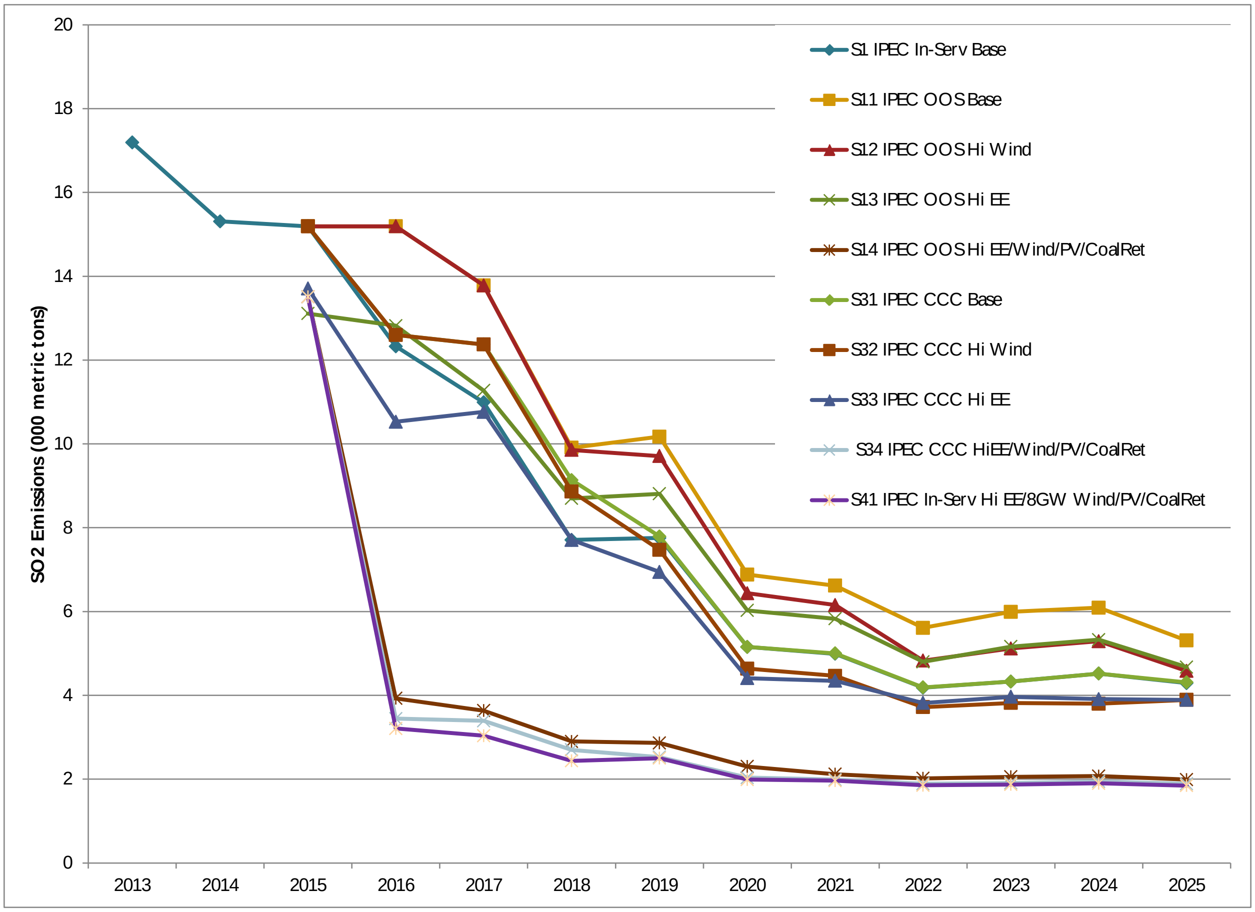
The SO_2 and NO_X emissions trends show a clear pattern of declining emissions over the years, with a more dramatic decline seen for the SO_2 emissions in scenarios where we assumed the retirement of some upstate coal units (only coal and oil units contribute to SO_2 emissions, as natural gas does not contain sulfur). Each of the two figures shows a predominant pattern of declining emissions from in-state resources. Increasing use of wind and solar, reduced use of coal, and increasing use of newer gas-fired plants (displacing older, higher-NO_X-emitting gas plants) are the primary driving factors behind these trends.

Figure 7. Annual CO_2 Emissions, New York Electric Power Sector, 2015-2025, 10 Modeled Scenarios



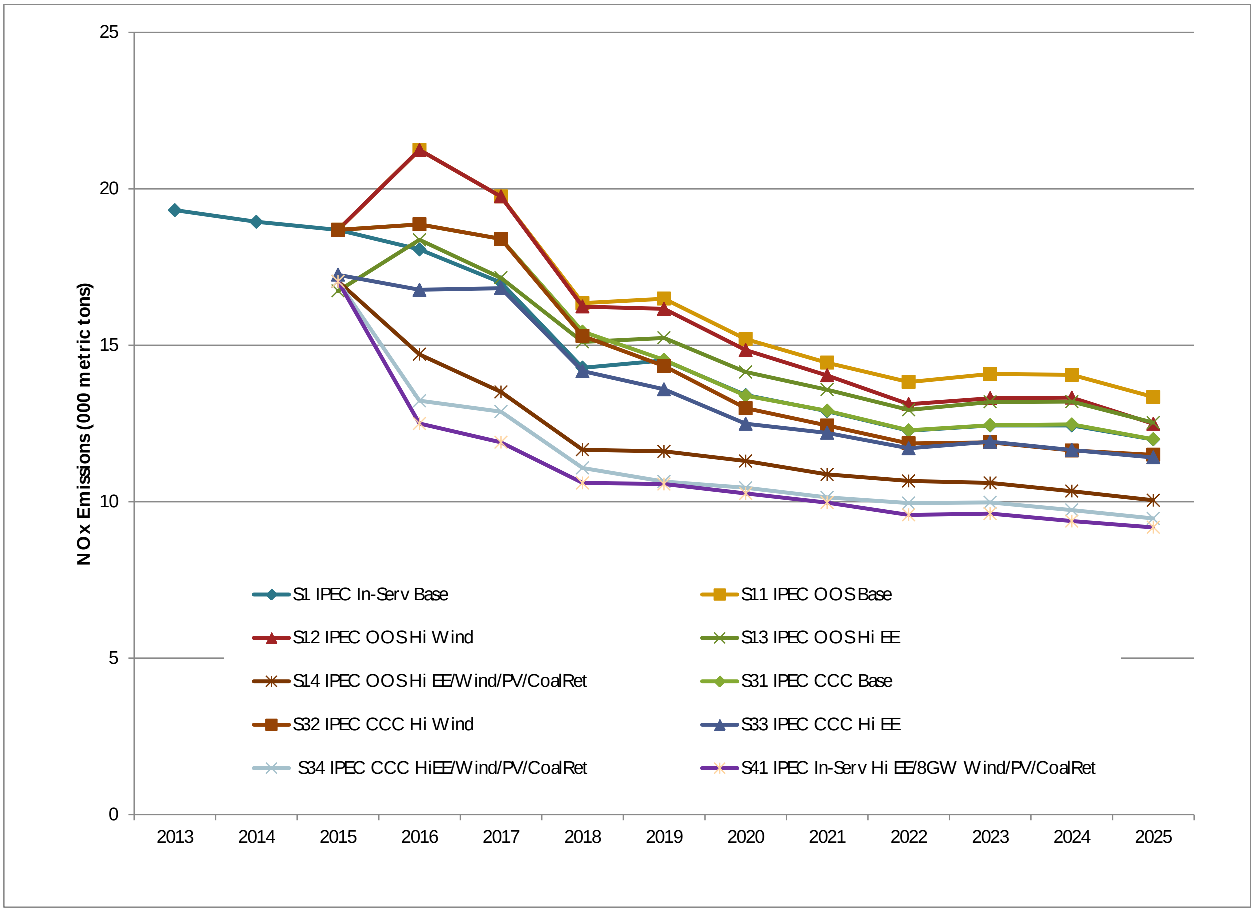
	S1 IPEC In-Serv Base	S11 IPEC OOS Base	S12 IPEC OOS Hi Wind	S13 IPEC OOS Hi EE	S14 IPEC OOS Hi EE/Wind/PV/CoalRet	S31 IPEC CCC Base	S32 IPEC CCC Hi Wind	S33 IPEC CCC Hi EE	S34 IPEC CCC HiEE/Wind/PV/CoalRet	S41 IPEC In-Serv Hi EE/8GW Wind/PV/CoalRet	RGGI Base Budget	RGGI Budget post-2020 estimated
2013	39,153										64,311	
2014	38,980										35,229	
2015	37,386	37,386	37,386	34,768	34,458	37,386	37,386	34,851	34,458	34,458	34,348	
2016	38,194	43,219	43,219	40,330	36,807	38,977	38,977	35,938	33,119	32,321	33,489	
2017	37,425	42,449	42,449	39,410	36,130	40,248	40,248	37,371	34,222	31,624	32,652	
2018	34,836	40,089	39,738	37,246	34,129	37,580	37,220	34,688	31,813	29,322	31,836	
2019	34,742	40,008	39,189	37,201	33,649	34,911	34,191	32,301	29,222	28,749	31,040	
2020	34,940	40,036	38,956	37,516	34,015	35,125	34,004	32,657	29,699	28,267	30,264	
2021	35,863	40,737	39,366	38,531	34,716	36,046	34,663	33,887	30,585	29,165		29,507
2022	35,715	40,602	38,727	38,376	34,427	35,905	34,192	33,804	30,283	28,206		28,770
2023	35,914	40,796	38,643	38,585	34,129	36,090	34,110	34,090	30,079	28,067		28,050
2024	36,140	40,991	38,574	38,747	33,895	36,288	33,966	34,089	29,873	27,893		27,349
2025	36,530	41,193	38,531	39,050	34,122	36,711	34,240	34,604	30,185	28,205		26,665

Figure 8. Annual SO_2 Emissions, New York Electric Power Sector, 2015-2025, 10 Modeled Scenarios



	S1 IPEC In-Serv Base	S11 IPEC OOS Base	S12 IPEC OOS Hi Wind	S13 IPEC OOS Hi EE	S14 IPEC OOS Hi EE/Wind/PV/CoalRet	S31 IPEC CCC Base	S32 IPEC CCC Hi Wind	S33 IPEC CCC Hi EE	S34 IPEC CCC HiEE/Wind/PV/CoalRet	S41 IPEC In-Serv Hi EE/8GW Wind/PV/CoalRet
2013	17.2									
2014	15.3									
2015	15.2	15.2	15.2	13.1	13.5	15.2	15.2	13.7	13.5	13.5
2016	12.3	15.2	15.2	12.8	3.9	12.6	12.6	10.5	3.4	3.2
2017	11.0	13.8	13.8	11.3	3.6	12.4	12.4	10.8	3.4	3.0
2018	7.7	9.9	9.9	8.7	2.9	9.1	8.9	7.7	2.7	2.4
2019	7.8	10.2	9.7	8.8	2.9	7.8	7.5	6.9	2.5	2.5
2020	5.2	6.9	6.4	6.0	2.3	5.2	4.6	4.4	2.0	2.0
2021	5.0	6.6	6.2	5.8	2.1	5.0	4.5	4.3	2.0	2.0
2022	4.2	5.6	4.8	4.8	2.0	4.2	3.7	3.8	1.9	1.9
2023	4.3	6.0	5.1	5.2	2.1	4.3	3.8	4.0	1.9	1.9
2024	4.5	6.1	5.3	5.3	2.1	4.5	3.8	3.9	1.9	1.9
2025	4.3	5.3	4.6	4.7	2.0	4.3	3.9	3.9	1.9	1.8

Figure 9. Annual NOX Emissions, New York Electric Power Sector, 2015-2025, 10 Modeled Scenarios



	S1 IPEC In-Serv Base	S11 IPEC OOS Base	S12 IPEC OOS Hi Wind	S13 IPEC OOS Hi EE	S14 IPEC OOS Hi EE/Wind/PV/CoalRet	S31 IPEC CCC Base	S32 IPEC CCC Hi Wind	S33 IPEC CCC Hi EE	S34 IPEC CCC HiEE/Wind/PV/CoalRet	S41 IPEC In-Serv Hi EE/8GW Wind/PV/CoalRet
2013	19.3									
2014	18.9									
2015	18.7	18.7	18.7	16.7	17.0	18.7	18.7	17.3	17.0	17.0
2016	18.1	21.2	21.2	18.4	14.7	18.9	18.9	16.8	13.2	12.5
2017	17.0	19.8	19.8	17.2	13.5	18.4	18.4	16.8	12.9	11.9
2018	14.3	16.3	16.2	15.1	11.7	15.4	15.3	14.2	11.1	10.6
2019	14.5	16.5	16.2	15.2	11.6	14.5	14.3	13.6	10.6	10.6
2020	13.4	15.2	14.8	14.1	11.3	13.4	13.0	12.5	10.4	10.3
2021	12.9	14.4	14.0	13.6	10.9	12.9	12.4	12.2	10.1	10.0
2022	12.3	13.8	13.1	12.9	10.7	12.3	11.9	11.7	10.0	9.6
2023	12.4	14.1	13.3	13.2	10.6	12.4	11.9	11.9	10.0	9.6
2024	12.4	14.1	13.3	13.2	10.3	12.5	11.6	11.7	9.7	9.4
2025	12.0	13.3	12.5	12.5	10.0	12.0	11.5	11.4	9.5	9.2

New York Wholesale Locational Energy Prices

The purpose of our analysis was to show how emissions change under different outage scenarios, and under different assumptions for energy efficiency, wind and solar installations, and transmission reinforcement. In conducting this analysis, we also estimated replacement power resources under IPEC outage scenarios. However, economic dispatch modeling also produces zonal clearing prices, reflective of the wholesale market locational prices in New York. One can assess the broad price trends associated with different outage scenarios and in combination with other key assumptions. Table 13 below shows the base case (scenario 1) prices from our scenario modeling. Tables 14 and 15 that follow show the relative price change from the base scenario pricing for two scenarios, one with IPEC fully out of service from 2016-2025 and no change to other assumptions (scenario 11), and one with IPEC fully out of service from 2016-2025 with installation of increased energy efficiency, wind, and PV resources (scenario 14).

Table 13. New York Wholesale Energy Prices by PROSYM New York Zone, 2015-2025, Scenario 1 (IPEC In-Service)

2012 $/MWh	**AB**	**CDE**	**F**	**GHI**	**J**	**K**
2015	36.1	37.5	39.4	41.9	44.6	46.0
2016	36.8	38.2	40.2	42.2	45.9	48.1
2017	38.0	39.3	41.3	43.3	46.1	48.4
2018	37.8	38.9	40.8	42.7	44.5	49.2
2019	39.0	40.3	42.1	44.0	45.8	51.0
2020	42.5	43.5	45.4	47.4	49.5	54.8
2021	44.9	45.4	47.4	49.5	51.5	55.5
2022	46.4	47.0	49.1	51.2	53.0	57.6
2023	48.5	49.0	51.1	53.3	55.1	60.2
2024	50.1	50.6	52.9	55.2	57.0	60.1
2025	51.8	52.3	54.7	57.0	58.4	60.9

Source: 2014 Synapse PROSYM Production Cost Model Run, Scenario 1

Table 14. New York Wholesale Energy Price Change from Base Scenario 1, Percent, by PROSYM New York Zone, 2015-2025, Scenario 11 (IPEC Out of Service, Base case values for EE, Wind, PV)

	AB	CDE	F	GHI	J	K
2015	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2016	3.3%	3.9%	4.3%	9.7%	2.5%	1.2%
2017	3.2%	3.8%	4.2%	6.5%	1.7%	0.7%
2018	3.0%	3.5%	3.9%	4.6%	1.7%	0.0%
2019	3.5%	4.1%	4.1%	4.2%	1.7%	-0.1%
2020	3.0%	3.7%	3.7%	3.7%	1.2%	-0.3%
2021	2.7%	3.3%	3.3%	3.4%	1.4%	0.2%
2022	2.5%	3.0%	3.1%	3.3%	1.6%	0.0%
2023	2.4%	3.0%	3.1%	3.3%	1.4%	0.1%
2024	2.3%	2.8%	2.9%	3.0%	1.3%	0.5%
2025	2.1%	2.6%	2.7%	2.8%	1.6%	1.0%

Source: 2014 Synapse PROSYM Production Cost Model Run, Delta, Sc. 11 minus Sc. 1

Table 15. New York Wholesale Energy Price Change from Base Scenario 1, Percent, by PROSYM New York Zone, 2015-2025, Scenario 14 (IPEC Out of Service, High EE, High Wind, High PV)

	AB	CDE	F	GHI	J	K
2015	-3.9%	-3.6%	-2.7%	-3.1%	-2.5%	-1.9%
2016	3.3%	2.6%	3.8%	7.3%	0.0%	-1.2%
2017	2.9%	2.4%	3.4%	4.7%	-0.3%	-1.2%
2018	0.7%	0.9%	2.3%	2.7%	-0.2%	-1.8%
2019	1.5%	1.7%	2.3%	2.3%	-0.3%	-2.4%
2020	0.5%	1.2%	1.7%	1.8%	-0.6%	-2.2%
2021	-0.1%	0.8%	1.2%	1.3%	-0.6%	-1.7%
2022	-0.9%	0.0%	0.8%	1.0%	-0.6%	-1.9%
2023	-1.5%	-0.4%	0.5%	0.7%	-0.8%	-2.1%
2024	-2.5%	-1.2%	0.2%	0.4%	-0.9%	-1.8%
2025	-3.1%	-1.8%	-0.1%	0.1%	-0.6%	-1.4%

Source: 2014 Synapse PROSYM Production Cost Model Run, Delta, Sc. 14 minus Sc. 1

Tables 14 and 15 illustrate two fundamental price aspects of the New York wholesale electric power market. Table 14 shows that all else equal, loss of the IPEC output has an effect on energy prices, although the average effect is minimal; in particular, downstate zones show very low price increases, reflecting the economics of a constrained power system. The average effect varies by zone, due to transmission loss and congestion effects. The tables do not show variation in prices within the year, or between day and night,[45] but generally the average annual effect shown here is more pronounced during periods when load is higher, and less pronounced during periods when load is lower.

Table 15 demonstrates that increased energy efficiency, and increased deployment of inframarginal,[46] zero-fuel cost wind, and solar PV, mitigate the price impacts associated with the loss of output from IPEC units. As seen, price changes seen with IPEC out of service with increased deployment of these resources are lower than price changes without these resources, and in some zones in some years—especially the J and K downstate zones of NYC and LI in all years—absolute prices are lower in scenario 14 (IPEC fully out of service, but high levels of energy efficiency, wind, and PV) than they are in the base scenario.

For the scenarios involving sequential year-long outages at Indian Point Units 3 and 2 in 2017 and 2016, respectively following a 60-day fish protection outage in 2016 (scenarios 31 and 34), the price impacts will be non-existent in later years (once both units are back in service); and, unless outages take longer than anticipated, will be less than is seen for the fully out-of-service from 2016-2025 scenarios shown here since construction outages are estimated to last less than a full year.[47]

2.4. Discussion

Changes in resource output across locations in New York State are influenced significantly by interdependent changes in projected load, key transmission reinforcements planned and proposed for New York's transmission system, and the availability of both renewable resources and new gas-fired generation in zone GHI. These influences are clearly seen in the near term by the downward trajectory of emissions between 2017 and 2019 in all scenarios, as the effect of critical near-term, congestion-reducing transmission reinforcement, GHI-zone gas-fired resources, and increases in upstate wind help to reduce fossil-fuel use downstate, even with IPEC outages. Over the longer-term, NO_X and SO_2 emissions continue their decline in all scenarios, as coal use declines and reduced NO_X emissions from newer gas-fired sources replace older unit output. CO_2 emissions flatten out after 2019, but remain roughly at the RGGI benchmark under scenarios with higher levels of energy efficiency, wind and PV and with closed cycle cooling installed at IPEC in sequential year-long outages and in place by the end of 2018 (scenario 34). CO_2 emissions are higher for scenarios that do not include more aggressive pursuit of energy efficiency and renewable resources, and if IPEC were not in service. However, based on differential CO_2 emissions between scenario 34 and scenario 41, (scenario 41 is our bookend scenario for lowest CO_2 emissions, with IPEC in service, high levels of energy efficiency, PV, and wind, including 2 additional GW of wind (8,117 MW total by 2025)) it can be seen that CO_2 emissions can be lowered with

45 The New York electric energy market prices electricity on an hourly basis, thus price variation exists on multiple time scales across the year.

46 "Inframarginal" refers to generation units that do not set the clearing price and have the effect of "stretching" the system supply curve such that for any given level of demand, prices are lower.

47 For example, the Tetra Tech report indicates a 30 to 35 week outage period (p. 23) and the Enercon report indicates a 42-week outage period (Attachment 9).

additional renewables – or increased levels of energy efficiency. For example, by 2025, Scenario 41 has CO_2 emissions that are 2.2 million metric tons per year lower than the emissions of scenario 34 (IPEC in-service with closed cycle cooling installed by end of 2018 after sequential year-long outages) thus indicating a 6.6% reduction in carbon emissions for a scenario with that level of incremental wind (roughly 2 GW). The later years of our analysis also include declining imports; any increases in the levels of renewable resources from Canada will further displace gas-fired generation in New York.

Without considering incremental energy efficiency and new renewable resources, replacement power patterns demonstrate the near-term use of existing (and new) natural gas resources, and imports (generally, imports will be sourced from gas-fired resources in adjacent regions). As transmission is reinforced, upstate resources with lower operating costs than downstate resources substitute for downstate resources (wind, a zero-cost fuel resource, will always be dispatched before fossil-fired resources up to the point where transmission is constraining). In the near term, if energy efficiency and renewables are not able to be deployed in any significant amount, New York City gas generation makes up roughly one-fifth to one-quarter of replacement power needs, but this represents a smaller fractional increase in New York City zone J gas-fired generation: for example, in the scenario in which closed cycle cooling is installed in sequential year long outages in 2017 and 2018 (scenario 31) in 2017, zone J sees an 11% increase in gas-fired generation from 27.2 TWh to 30.3 TWh.[48]

If improvements in energy efficiency and deployment of renewable resources are considered, replacement power needs from gas-fired fuel are significantly lower. Over the longer-term, New York City (zone J) will not see increases in gas use beyond what will occur in a base case without increases in energy efficiency and renewable supplies. In all modeled cases, any oil use in New York City is limited to very-high-demand days, as annual levels of oil consumption remain extremely low (less than 0.05% of annual energy consumed in the state).

Price increases in the event of IPEC out-of-service are limited. Under all scenarios of higher levels of energy efficiency and renewable energy deployment, price increases are mitigated.

3. RELIABILITY ASSESSMENT

Synapse assessed the likely reliability impacts of an Indian Point Energy Center dual-unit outage as of the summer of 2016.[49] Such an outage can arise from being offline for the construction of closed cycle cooling , being offline during the summer as a protective outage, or from a decision to permanently

[48] Model output by zone for gas, for zone J, scenarios 31 and 1.

[49] The reliability assessments reflected in the NYS PSC Contingency Plan docket focuses on ensuring reliability in the summer of 2016, the first year in which an IPEC outage might affect reliability. The resources that would be in place to meet 2016 needs would also be available in 2017 and later years, along with ongoing resource additions that would ensure reliability in those future years.

retire. Counsel for Riverkeeper has informed Synapse that Riverkeeper's position is that scenarios relating to shutdown of the facility in connection with NYSDEC April 2, 2010 Denial of Entergy's requested Clean Water Act Section 401 water quality certification is properly the subject of review under the NEPA in connection with the Entergy NRC license renewal proceeding rather than under the NYSDEC SEQRA review process. Accordingly, we analyzed the dual-outage scenario as a "worst case"/bounding scenario, and to help us to understand analytically how the system will respond to the loss of a large energy-supplying facility. Importantly, reliability is tested under extreme case scenarios, and our assessment does not reflect any particular outcome or mitigation approach for IPEC, but merely examines the assumptions already under consideration by the NY ISO (as reflected in the 2012 RNA) and the NYS PSC (in Case E-12-0503).

We conducted our reliability assessment by reviewing the most recent and most relevant materials available from the NYISO and from ongoing investigations before the New York PSC. The focus of our assessment was to determine if there is reasonable indication that New York electric power sector reliability would be maintained in 2016 under the circumstance where the IPEC units are offline in the summer of 2016. While the NYISO's 2012 Reliability Need Assessment (RNA) indicated reliability violations in 2016 if IPEC was out of service, it also indicated that roughly 1,000 MW of "compensatory MW" of capacity would be needed by 2016 to *preserve* reliability; more recently, the NYISO has confirmed that 1,100 MW of "replacement resources" need to be in place prior to a 2-unit IPEC outage.[50] The 2012 RNA did not include transmission, demand-side, and supply-side resources under development or existing as potentially available resources when computing the metrics that indicated a reliability violation if IPEC was out of service. The NYISO is scheduled to conduct its next Reliability Need Assessment in 2014. The capacity need indicated in the 2012 RNA and mentioned in the NYISO's September 2013 testimony is in the process of being developed, and it appears likely that it will be available by 2016. Thus, this assessment finds there is a reasonable indication that reliability will be maintained in 2016 even with outage of both units, since there is evidence of sufficient resource development that will allow for reliable operation.

The resource development activity is in the right locations in New York. It has come about through development of an Indian Point reliability contingency plan, and imminent electric capacity market construct changes in New York State. It includes NYS PSC-approved demand-side and transmission resources, and market-based development of new and potentially refurbished existing generation supply. Notably, much of the formal NYISO analysis (the 2012 RNA)—conducted in 2012 as part of the regular biennial cycle for reliability assessment—is based on 2012 data that excluded the presence of resources now projected to be in place by 2016. While updates to these analyses from NYISO are expected during 2014, it is not too early to conclude that Indian Point Energy Center reliability contingency plans and electric wholesale market developments will allow for reliable operation in New York in 2016. The primary basis for that conclusion is evidence of resource development that is directly

[50] Thomas Rumsey, NY ISO, testimony before the New York State Senate Energy and Telecommunications Committee, September 30, 2013.

targeted to mitigate reliability effects that might otherwise be seen if the IPEC units were to be out of service in 2016.

3.1. Reliability Overview

The New York State electric power system is an interconnected grid with hundreds of generation units providing roughly 38 Gigawatts (GW, equal to 1,000 MW) of summer capacity, and together with multiple GW of additional import capacity (from Quebec, Ontario, New England, and PJM) it supplies a varying demand that ranges roughly from a low of roughly 12 GW to a high of 33 GW.[51] Generation unit sizes vary, from less than 1 MW to more than 1,000 MW. A very hot summer day is generally the most stressful period for reliable operation, and is the period tested by the NYISO when assessing resource adequacy and transmission security of the electric power system.

Reliability is formally defined by the NYISO as having sufficient resource adequacy (essentially, high probability of sufficient supply to meet net demand on the highest load day) and sufficient transmission security (reliable operation even when confronted with the unexpected sequential loss of multiple transmission circuits during the time of highest peak load). The New York State Reliability Council oversees the reliability "rules of the road"[52] that must be adhered to by utilities and the NYISO, and these rules dictate the types of planning analyses conducted by the NYISO to evaluate reliability. For resource adequacy, reliability dictates a threshold level of computed probability of loss of load (no more than 1 day in 10 years). This is performed as part of the biennial RNA, and is also done each year as part of the Installed Reserve Margin (IRM) calculation used in specifying local capacity requirements in New York.[53] For transmission security, reliability requires secure operation for stressful system conditions when multiple transmission elements may be out of service. This is performed using power flow modeling techniques during the biannual RNA.

The NYISO assesses reliability of the New York State power system constantly for operational purposes, and at mostly regular intervals for planning purposes. In addition, the electric utilities in New York conduct their own reliability analyses. The NYISO's most recent planning assessment of reliability was contained in the 2012 Reliability Needs Assessment, produced as part of the Comprehensive Reliability Planning Process (CRPP). The CRPP also includes annual assessment of Resource Adequacy requirements for local areas, which contains the requirements for capacity for three separate local capacity zones, namely New York City, Long Island, and the rest of the State of New York. In 2014, an additional local

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[51] NYISO 2013 Gold Book summer capacity total equals 37,920 MW. Peak load including losses and adjusted for weather in the summer of 2013 was 33,497.1 MW (NY ISO, "2013 Weather Normalized MW and Preliminary 2014 ICAP Forecast", Load Forecast Task Force presentation by Arthur Mancini, December 17, 2013). Low load figure from Figure A-11: Load Duration Curves for New York State, 2010-2012 (page A-16), from the 2012 State of the Market Report for the New York ISO Market, Potomac Economics, April 2013.

[52] New York State Reliability Council, NYSRC Reliability Rules for Planning and Operating the New York State Power System, Version 32, January 11, 2013.

[53] Local capacity requirements exist for the New York ISO zone J (New York City), the Long Island zone (K), and beginning in 2014, for the locality defined as the combination of NY ISO zones G, H, I and J.

capacity zone (comprised of the combination of the New York City zone J and the Lower Hudson Valley region zones G, H, and I) will be created to reflect recognition of the impact of a critical transmission constraint—the UPNY/SNEY (Upstate New York/Southeast New York)—on power flows in the region.

3.2. Status of IPEC Outage Contingency Plans

The status of reliability planning for the possible outage of IPEC indicates that reliability is not likely to be a major concern in 2016, as long as the planned improvements and anticipated market-based generation resources are deployed.

We summarize the most recently available, relevant information on the status of the reliability of the New York power system under an Indian Point summer 2016 outage, based on the NYS PSC proceeding on reliability contingency planning.[54] For the purpose of determining possible resource need, the contingency plans presume the outage of both IPEC units but the NYS PSC makes no determinations concerning any particular level of IPEC outage that may be in place by 2016.

The NYS PSC identifies[55] a 1,450 MW summer 2016 capacity need ("potential reliability need"[56]) requirement based on an earlier utility filing (ConEd and NYPA February 2013 IPEC Contingency Plan, see below), the NY ISO 2012 RNA, ConEd/NYPA's update to the 2012 RNA analysis, DPS Staff analysis, and the closure of the Danskammer plant (announced after the 2012 RNA). In the Order, which acts upon the ConEd/NYPA contingency plan filing, the Commission approves 185 MW of energy efficiency, demand response and combined heat and power resources that reduce the need, and anticipates a further 600 MW contribution[57] towards that need from three transmission projects (the "Transmission Owners Transmission Solutions," or TOTS) whose initial development costs were approved in this Order.

The TOTS projects are summarized in Table 16 below. Notably, all of the projects, both individually and in combination, contribute towards reducing the resource deficiency identified and described in the November 2013 NYS PSC Order on the IPEC Contingency Plan.

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[54] The NYS PSC proceeding is characterized as Generation Retirement Contingency Plan. For purposes of our *reliability assessment*, we assumed the worst case outage considered by the NYISO—unavailability of the units in the summer of 2016. This does not imply that IPEC retires. Testing for reliability concerns presumes the units not available during the peak load periods in the summer, and such testing is blind to the reasons for the outage, and is not concerned with whether or not the units are back online during non-peak, non-summer periods. Our *emissions assessment* contains multiple scenarios of IPEC outages and accounts for different periods of outage at different times of the year, over the years 2015 through 2025. Those scenarios include both full retirement, and "partial outage" conditions such as would be seen with the construction and installation of closed cycle cooling.

[55] New York PSC Order on Contingency Plans, November 2013. Initiating Order and April 2013 Order in the IPEC Reliability Contingency Plan docket at the New York Public Service Commission. *Order Instituting Proceeding And Soliciting Indian Point Contingency Plan,* New York State Public Service Commission, Case 12-E-0503, November 30, 2012.

[56] Order, page 3 and pages 18-21.

[57] Order at 6, 22, and 24.

Table 16. Transmission Owner Transmission Solution (TOTS) Projects

TOTS Project Name	Description	In-Serv. Date	Effect on Reliability Need
2nd Ramapo to Rock Tavern	2nd 345 kV overhead circuit on existing right-of-way between Ramapo and Rock Tavern substations in Zone G.[58]	May 2016	Increase import capability into Southeastern New York, including NYC, during normal and emergency conditions and will provide partial solution for system reliability if IPEC retires. UPNY/ConEd interface limit increase of 1,425 MW (normal) and 2,780 MW (emergency). UPNY/SENY interface limit increase of 120 MW (normal) and 135 MW (emergency). Total East interface limit increase of 60 MW (normal) and 65 MW (emergency).[59] 100 MW reduction in N-1/-1 deficiency post-IPEC shutdown. In combination w/ MSSC, 480 MW reduction in N-1/-1 deficiency post-IPEC shutdown.
Marcy South Series Compensation and Fraser to Coopers Corner Reconductoring	Switchable series compensation on the 345 kV Marcy South transmission lines and reconductoring a section of the Fraser to Coopers Corner FCC-33 line.	June 1, 2016	Increase thermal transfer limits across Total East and the UPNY/SENY interface / provide partial solution for system reliability if IPEC retires.[60]Total East transfer limit increase of 444 MW[61], increases power flow from Zone E into Zones F and G.[62]
Staten Island Unbottling	Increase transmission capability between Gowanus, Goethals, and Farragut via forced cooling to increase thermal capacity. Reconfigure Goethals to Linden feeder (L&M legs).	May 2016	New resource that "unbottles" generation on Staten Island (zone J). Reduces N-1/-1 post IPEC shutdown deficiency by 440 MW. Partial solution to reliability needs if IPEC retires. Reduces severity of 2nd contingency violation in NYC. Increases transfer capability between Staten Island generation pocket and the rest of the 345 kV system in NYC. Allows greater access to PJM resources, expected to reduce dispatch of fossil generation in NYC and Long Island.[63]

[58] Three concurrent transmission upgrades will be completed. O&R feeder 28 (Ramapo 138 kV to Sugarloaf 138 kV) will be upgraded to 345 kV. Creation of Sugarloaf 345 kV station with 345/138 kV transformation. Install 345 kV line between Rock Tavern and Sugarloaf. Page 15, Exhibit C "Detailed Description of the Second Ramapo Rock Tavern 345 kV line," ConEd/NYPA compliance filing, February 1, 2013.

[59] Con Edison Company of New York, Additional Information on Transmission Owner Transmission Solution for Indian Point Contingency Plan, Second Ramapo to Rock Tavern 345 kV Line Project, May 20, 2013, pages 8-10.

[60] ConEd / NYPA Compliance Filing with respect to development of Indian Point Contingency Plan, Proceeding on Motion of the Commission To Review Generation Retirement Contingency Plan, Case 12-E-0503, Exhibit B, "Detailed Description of the Marcy South Series Compensation and Fraser to Coopers Corner Reconductoring Project, page 10. Filed February 1, 2013.

[61] Final Report of the System Impact Study for the MSSC project, NYISO queue #380.

[62] Submission of Comparable Information Pursuant to the April 19, 2013 Public Service Commission Order, Case 12-E-0503, Marcy South Series Compensation and Fraser to Coopers Corner Reconductoring Project, May 20, 2013.

[63] Consolidated Edison Company of New York, Additional Information on Transmission Owner Transmission Solution for Indian Point Contingency Plan: Staten Island Unbottling Project, May 20, 2013, Pages 6-12.

The result of these approvals leaves roughly a 665 MW shortfall in capacity needed to meet reliability requirements if IPEC was not available in the summer of 2016 (1,450 – 185 – 600 = 665 MW). The order notes the presence of approximately 1,500 MW of merchant generating units which have been "mothballed" or are "waiting to return to service if economic conditions improve," or "have been derated and require repair."[64] While the Order does not specifically state which units comprise that 1,500 MW, Synapse's review identifies four mothballed, derated, repair-requiring, or retired fossil-fueled units in the downstate or lower Hudson valley region that in total are roughly 1,528 MW: Astoria steam units 2 and 4 (177 MW and 376 MW, respectively); Bowline 2 (379 MW derated capacity); Astoria GT units 5, 7, 8, 12, and 13 (93.5); and Danskammer[65] 1-4 (503).[66] Excluding the retired Danskammer facility, the mothballed Astoria and derated portions of Bowline facilities combined include 1,025 MW of gas-fired capacity.

The Order also acknowledges the impending creation (beginning in 2014) of a new "Lower Hudson Valley" installed capacity zone in the NY ISO capacity market construct which can increase the revenues that would be available for the existing units to consider a return to service;[67] the new zone creation could also make it more likely that prospective new generation units in the LHV, namely the 678 MW (summer rating) CPV Valley plant, and the 1,020 MW (summer rating) Cricket Valley Energy Center would be constructed. The plants are currently listed with proposed in-service dates of May 2016 and January 2018, respectively.[68]

The NYS PSC Order did not approve, at that time, cost-based procurement of additional generation under the IPEC Reliability Contingency Plan. It notes that Con Edison and NYPA "should continue to monitor the status of projects which may enter or rejoin the generation market," and that those companies will need to assess if the IPEC Reliability Contingency Plan should expand the portfolio of resources (i.e., the TOTS projects and the energy efficiency, demand response and combined heat and power resources) to include other projects.[69]

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[64] Order, page 7.

[65] Danskammer was damaged during Hurricane Sandy ("Hurricane Sandy: A Report from the New York Independent System Operator", March 27, 2013, page 23) though it was not operating at the time of the storm.

[66] 2013 Gold Book, CRIS values for Astoria 2 (p. 60), Astoria 4 (p. 59), and the difference between CRIS and summer MW values for Bowline 2 (557.4-177.9 = 379.5 MW) (p.34).

[67] The New York ISO and the New York ISO Market Monitor (Potomac Economics) have analyzed the effect of the impending new capacity zone and determined that it will substantially increase revenues available to capacity resources in the G-H-I zones. Entergy has also acknowledged the need for the new capacity zone to support new entry and capacity value in the region.

[68] NY ISO Interconnection Queue, January 2014.

[69] Order at p. 46.

In parallel with the IPEC Reliability Contingency Plan docket, the NYS PSC is essentially entertaining options for additional transmission resources,[70] to be provided by either the existing New York transmission companies (together as a "Transco" or joint-ownership transmission company) or new entrants to the field.[71] This proceeding has resulted in a filing by the NY Transco of an intention to construct not only the TOTS facilities (approved in the Contingency Plan docket) but also additional transmission facilities that will increase the transfer capability across the key upstate New York/southeastern New York (UPNY/SENY) interface and the related Central East and Total East interfaces in central New York.

Increased capacity across these interfaces will allow for increased flow of energy from upstate New York resources including new wind resources, to the downstate area. While the TOTS infrastructure in planned for in-service by the summer of 2016, additional reinforcement of the UPNY/SENY interface and related reinforcements would not be in service until later years, 2018 and 2019. While such improvements do not support reliability need for 2016, they would serve to help enable retirement of older capacity resources that might be in place during the period immediately after an IPEC shutdown. The proposals submitted by the new entrants are similar in overall effect as the NY Transco proposals, in that they propose to increase transmission capacity between upstate and downstate New York areas.

In a written statement provided to the Senate Energy and Telecommunications Committee, NYISO Vice President of External Affairs Thomas Rumsey stated that in order to meet reliability needs, 1,100 MW of "replacement resources" would need to be in place prior to IPEC closure.[72] He indicated that "likely potential solutions" would include new generation, additional demand response, and limited transmission upgrades.[73] He referenced the 552 MW of generation currently "mothballed" at the Astoria facility, and approximately 1,900 MW of proposed generation projects identifying a commercial

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[70] E.g., 1) Order Instituting Proceeding. Case 12-T-0502, Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades. November 30, 2012. 2) Order Adopting Additional Procedures and Rule Changes for Review of Multiple Projects under Article VII of the Public Service Law, Case 12-T-0502, Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades, September 19, 2013. 3) Order Establishing Procedures for Joint Review Under Article VII of the Public Service Law and Approving Rule Changes, Case 12-T-0502, Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades, April 22, 2013. 4) New York Transco, Statement of Intent to Construct Transmission Facilities of Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. / Orange & Rockland Utilities, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric & Gas Corporation / Rochester Gas and Electric Corporation, New York Power Authority and the Long Island Power Authority on Behalf of the New York Transco, State of New York Public Service Commission Case 12-T-0502 – Proceeding on Motion to Examine Alternating Current Transmission Upgrades, Filed January 25, 2013. 5) New York Transco has also subsequently filed with the New York Public Service Commission, in Case 13-M-0457, "Submission of New York Transmission Owners for Authority To Construct and Operate Electric Transmission Facilities In Multiple Counties In New York, October 1, 2013. This filing describes the TOTS projects, and the additional 345 kV AC facilities (Edic to Pleasant Valley and the 2nd Oakdale to Fraser 345 kV transmission lines) planned for upstate New York.

[71] Transmission proposals include those from NextEra Energy Transmission, LLC; North America Transmission, LLC; Boundless Energy NE, LLC; and the New York Transco (comprised of the New York electric utilities).

[72] NY ISO Testimony before the NY Senate Energy and Telecommunications Committee, September 2013, reflecting the May 2013 Power Trends report; and the 2013 Power Trends Report.

[73] Written Statement of Thomas Rumsey, September 30, 2013, p. 8.

operation date in time for the summer of 2016.[74] While he did not explicitly identify the 1,900 MW of proposed generation projects, review of the information available on the NYISO generation interconnection queue indicates the following 2,400 MW of potential new projects in downstate zones (G or J) and potentially available by the summer of 2016, as seen in Table 17 below.

Table 17. New York ISO Generation Interconnection Queue, Downstate Zones, Summer 2016 Commercial Operation Date Indication (or earlier)

NYISO Queue Position	Plant Name	Summer MW	Fuel / Unit Type	County	NY ISO Zone	Connection Point	Utility	COD
251	CPV Valley Energy Center	678	CC-NG	Orange	G	Coopers – Rock Tavern 345kV	NYPA	2016/05
266	Berrians GT III	250	CC-NG	Queens	J	Astoria 345kV	NYPA	2016/06
349	Taylor Biomass	19	SW	Montgomery	G	Maybrook - Rock Tavern	CHGE	2015/12
361	Luyster Creek Energy	401	CC-D	Queens	J	Astoria West Substation 138kV	CONED	2015/06
382	South Pier Improvement	88	CT-NG	Kings	J	Gowanus Substation 138kV	ConEd	2015/07
383	Bowline Gen. Station Unit #3	775	CC-NG	Rockland	G	Ladentown Subsation 345kV	O&R/ ConEd	2016/06
400	Linden Cogen Uprate	208	CT-NG	Linden, NJ	J	Linden Cogen 345kV	ConEd	2016/Q2
	Total	2,419						

Note: NYISO Interconnection Queue data from January 2014.

The Power Trends report, from May 2013, stated "In addition, if the Indian Point Power Plant licenses are not renewed, and the plant were to retire by the end of 2015 or thereafter, this would result in immediate transmission security and resource adequacy criteria violations **unless sufficient replacement resources are in place prior to retirement**" (p19-20, emphasis added). In November 2012, the NY PSC asked Con Edison and the New York Power Authority to develop contingency plans to have resources in place in 2016 to address power supply needs in the event of Indian Point's closure (p36).

3.3. Outage Scenario Effect on Reliability

The planning for reliability undertaken by NYISO in the 2012 RNA, and undertaken by the NYS PSC in the Contingency Plan docket considers the extreme case that the IPEC plant is out of service (both units) in the summer of 2016. Reliability is a capacity-related concern. As long as sufficient, deliverable capacity resources are in place to mitigate reliability concerns under a situation where both units are modeled as out of service, then any combination of outage scenario will also be reliable – e.g., if any portion of

[74] Written Statement of Thomas Rumsey, September 30, 2013, p. 6.

either unit continues to be available in the summer of 2016, then operating reserve margins in the State will be even larger than they would be absent both units.

As long as sufficient capacity is in place, then different outage scenarios relating to the construction and installation of closed-cycle cooling at Indian Point will primarily impact estimates of replacement power and resulting emission patterns.

Given that sufficient replacement power will be adequate in the event that Indian Point goes fully offline permanently in 2016, it is reasonable to conclude that under *any* closed cycle cooling construction outage scenario, there will not be concerns with respect to reliability of the New York State electric system.

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Appendix A: Additional Modeling Data Tables

On the following pages, we present additional modeling data tables for:

- Energy Output by Zone by Scenario by Year by Fuel/Source
- Load by Zone, Base and High EE Scenarios

Scenario 1 - IPEC in base EE, Wind, PV	Nuclear	Hydro&PS	NatGas	Coal	Oil 6	Oil 2	Ker	Wind	Other (Wood, Refuse, Bio, PV, DR/LaaR)	Total
2015 Total All Zones	**39,975**	**27,273**	**67,425**	**5,376**	**-**	**6**	**1**	**5,865**	**3,146**	**149,066**
NY-AB (West)	4,151	14,891	1,928	4,924	-	-	-	1,072	828	27,793
NY-CDE (Cent North)	20,408	9,481	9,427	452	-	-	-	4,737	818	45,322
NY-F (Capital)	-	2,583	17,839	-	-	-	-	55	153	20,630
NY-GHI (Southeast)	15,417	318	746	-	-	-	-	-	535	17,016
NY-J (NY City)	-	-	25,909	-	-	-	-	-	54	25,964
NY-K (Long Island)	-	-	11,576	-	-	6	1	-	758	12,342
2016 Total All Zones	**39,502**	**27,303**	**71,323**	**4,961**	**-**	**19**	**3**	**5,884**	**3,287**	**152,283**
NY-AB (West)	4,487	14,897	1,886	4,527	-	-	-	1,077	831	27,704
NY-CDE (Cent North)	19,587	9,481	9,223	434	-	-	-	4,752	823	44,300
NY-F (Capital)	-	2,608	17,522	-	-	-	-	55	153	20,339
NY-GHI (Southeast)	15,428	318	4,269	-	-	0	-	-	535	20,550
NY-J (NY City)	-	-	26,837	-	-	2	-	-	182	27,021
NY-K (Long Island)	-	-	11,586	-	-	18	3	-	762	12,369
2017 Total All Zones	**39,941**	**27,352**	**71,176**	**4,556**	**3**	**8**	**2**	**6,121**	**3,278**	**152,436**
NY-AB (West)	4,113	14,894	1,794	4,129	-	-	-	1,071	829	26,830
NY-CDE (Cent North)	20,407	9,481	8,866	427	3	-	-	4,994	822	44,999
NY-F (Capital)	-	2,659	16,348	-	-	-	-	55	153	19,215
NY-GHI (Southeast)	15,421	318	5,854	-	-	-	-	-	533	22,126
NY-J (NY City)	-	-	27,176	-	-	0	-	-	184	27,361
NY-K (Long Island)	-	-	11,138	-	-	8	2	-	757	11,904
2018 Total All Zones	**39,069**	**32,847**	**70,248**	**3,159**	**-**	**3**	**1**	**6,123**	**3,246**	**154,695**
NY-AB (West)	4,149	14,870	1,619	2,761	-	-	-	1,071	820	25,291
NY-CDE (Cent North)	19,531	9,481	8,075	398	-	-	-	4,996	821	43,302
NY-F (Capital)	-	2,483	12,542	-	-	-	-	55	153	15,233
NY-GHI (Southeast)	15,388	318	12,568	-	-	-	-	-	532	28,807
NY-J (NY City)	-	5,694	24,914	-	-	-	-	-	167	30,775
NY-K (Long Island)	-	-	10,530	-	-	3	1	-	753	11,286
2019 Total All Zones	**40,298**	**32,863**	**69,651**	**3,231**	**-**	**4**	**1**	**6,128**	**3,252**	**155,428**
NY-AB (West)	4,474	14,878	1,603	2,832	-	-	-	1,072	826	25,685
NY-CDE (Cent North)	20,399	9,481	8,123	399	-	-	-	5,001	824	44,227
NY-F (Capital)	-	2,492	12,023	-	-	-	-	55	153	14,723
NY-GHI (Southeast)	15,425	318	12,505	-	-	-	-	-	532	28,781
NY-J (NY City)	-	5,694	24,779	-	-	-	-	-	166	30,639
NY-K (Long Island)	-	-	10,619	-	-	4	1	-	751	11,374
2020 Total All Zones	**39,149**	**32,885**	**73,053**	**2,221**	**-**	**3**	**1**	**6,458**	**3,253**	**157,022**
NY-AB (West)	4,126	14,882	1,588	1,864	-	-	-	1,077	820	24,358
NY-CDE (Cent North)	19,586	9,481	7,999	357	-	-	-	5,326	826	43,574
NY-F (Capital)	-	2,509	12,496	-	-	-	-	55	153	15,214
NY-GHI (Southeast)	15,436	318	15,321	-	-	-	-	-	533	31,609
NY-J (NY City)	-	5,694	25,132	-	-	-	-	-	165	30,991
NY-K (Long Island)	-	-	10,517	-	-	3	1	-	754	11,276
2021 Total All Zones	**39,977**	**32,856**	**77,106**	**2,098**	**9**	**2**	**1**	**7,145**	**3,299**	**162,493**
NY-AB (West)	4,151	14,875	1,574	1,753	-	-	-	1,315	821	24,489
NY-CDE (Cent North)	20,405	9,481	7,856	345	9	-	-	5,775	855	44,725
NY-F (Capital)	-	2,488	11,134	-	-	-	-	55	165	13,842
NY-GHI (Southeast)	15,422	318	17,985	-	-	-	-	-	532	34,257
NY-J (NY City)	-	5,694	26,141	-	-	-	-	-	170	32,005
NY-K (Long Island)	-	-	12,417	-	-	2	1	-	756	13,175
2022 Total All Zones	**39,389**	**32,860**	**78,111**	**1,683**	**-**	**2**	**1**	**7,675**	**3,300**	**163,021**
NY-AB (West)	4,475	14,877	1,517	1,350	-	-	-	1,539	818	24,576
NY-CDE (Cent North)	19,535	9,481	7,706	333	-	-	-	6,081	862	43,997
NY-F (Capital)	-	2,490	10,929	-	-	-	-	55	165	13,639
NY-GHI (Southeast)	15,379	318	17,841	-	-	-	-	-	532	34,071
NY-J (NY City)	-	5,694	27,789	-	-	-	-	-	168	33,651
NY-K (Long Island)	-	-	12,328	-	-	2	1	-	755	13,087
2023 Total All Zones	**39,926**	**32,914**	**78,142**	**1,801**	**-**	**3**	**1**	**8,193**	**3,374**	**164,354**
NY-AB (West)	4,114	14,884	1,507	1,464	-	-	-	1,536	819	24,324
NY-CDE (Cent North)	20,396	9,481	7,617	337	-	-	-	6,602	934	45,367
NY-F (Capital)	-	2,536	10,907	-	-	-	-	55	165	13,664
NY-GHI (Southeast)	15,416	318	17,970	-	-	-	-	-	532	34,235
NY-J (NY City)	-	5,694	27,818	-	-	-	-	-	166	33,678
NY-K (Long Island)	-	-	12,322	-	-	3	1	-	759	13,086
2024 Total All Zones	**39,182**	**32,972**	**78,632**	**1,985**	**-**	**1**	**0**	**9,123**	**3,386**	**165,280**
NY-AB (West)	4,162	14,887	1,508	1,639	-	-	-	1,544	818	24,558
NY-CDE (Cent North)	19,590	9,481	7,601	346	-	-	-	6,915	946	44,878
NY-F (Capital)	-	2,592	10,448	-	-	-	-	55	166	13,261
NY-GHI (Southeast)	15,430	318	17,447	-	-	-	-	-	533	33,728
NY-J (NY City)	-	5,694	27,279	-	-	-	-	-	165	33,138
NY-K (Long Island)	-	-	14,349	-	-	1	0	609	759	15,717
2025 Total All Zones	**40,287**	**32,984**	**80,435**	**1,824**	**-**	**0**	**-**	**9,158**	**3,521**	**168,209**
NY-AB (West)	4,473	14,896	1,494	1,485	-	-	-	1,539	810	24,697
NY-CDE (Cent North)	20,397	9,481	7,436	339	-	-	-	6,900	1,083	45,636
NY-F (Capital)	-	2,595	9,444	-	-	-	-	55	165	12,259
NY-GHI (Southeast)	15,417	318	16,477	-	-	-	-	-	531	32,744
NY-J (NY City)	-	5,694	29,069	-	-	-	-	55	165	34,983
NY-K (Long Island)	-	-	16,514	-	-	0	-	608	767	17,890

Scenario 11 - IPEC OOS base EE, Wind, PV	Nuclear	Hydro&PS	NatGas	Coal	Oil 6	Oil 2	Ker	Wind	Other (Wood, Refuse, Bio, PV, DR/LaaR)	Total
2015 Total All Zones	**39,975**	**27,273**	**67,425**	**5,376**	**-**	**6**	**1**	**5,865**	**3,146**	**149,066**
NY-AB (West)	4,151	14,891	1,928	4,924	-	-	-	1,072	828	27,793
NY-CDE (Cent North)	20,408	9,481	9,427	452	-	-	-	4,737	818	45,322
NY-F (Capital)	-	2,583	17,839	-	-	-	-	55	153	20,630
NY-GHI (Southeast)	15,417	318	746	-	-	-	-	-	535	17,016
NY-J (NY City)	-	-	25,909	-	-	-	-	-	54	25,964
NY-K (Long Island)	-	-	11,576	-	-	6	1	-	758	12,342
2016 Total All Zones	**24,074**	**27,303**	**80,053**	**5,906**	**12**	**30**	**4**	**5,884**	**3,331**	**146,597**
NY-AB (West)	4,487	14,897	2,177	5,436	-	-	-	1,077	837	28,910
NY-CDE (Cent North)	19,587	9,481	10,219	470	12	-	-	4,752	825	45,347
NY-F (Capital)	-	2,608	19,960	-	-	-	-	55	154	22,778
NY-GHI (Southeast)	-	318	5,350	-	-	1	-	-	550	6,218
NY-J (NY City)	-	-	29,916	-	-	2	-	-	199	30,117
NY-K (Long Island)	-	-	12,430	-	-	28	4	-	766	13,228
2017 Total All Zones	**24,519**	**27,352**	**80,283**	**5,444**	**31**	**17**	**3**	**6,121**	**3,301**	**147,071**
NY-AB (West)	4,113	14,894	2,058	4,987	-	-	-	1,071	835	27,957
NY-CDE (Cent North)	20,407	9,481	9,791	457	31	-	-	4,994	824	45,985
NY-F (Capital)	-	2,659	19,312	-	-	-	-	55	153	22,179
NY-GHI (Southeast)	-	318	6,995	-	-	0	-	-	542	7,855
NY-J (NY City)	-	-	30,257	-	-	1	-	-	188	30,446
NY-K (Long Island)	-	-	11,870	-	-	16	3	-	759	12,648
2018 Total All Zones	**23,681**	**32,847**	**80,885**	**4,126**	**-**	**4**	**1**	**6,123**	**3,268**	**150,935**
NY-AB (West)	4,149	14,870	1,774	3,699	-	-	-	1,071	827	26,391
NY-CDE (Cent North)	19,531	9,481	8,849	427	-	-	-	4,996	824	44,108
NY-F (Capital)	-	2,483	16,228	-	-	-	-	55	153	18,920
NY-GHI (Southeast)	-	318	14,591	-	-	-	-	-	537	15,446
NY-J (NY City)	-	5,694	28,536	-	-	-	-	-	172	34,403
NY-K (Long Island)	-	-	10,909	-	-	4	1	-	754	11,668
2019 Total All Zones	**24,873**	**32,863**	**80,318**	**4,150**	**7**	**5**	**1**	**6,128**	**3,265**	**151,610**
NY-AB (West)	4,474	14,878	1,780	3,722	-	-	-	1,072	833	26,760
NY-CDE (Cent North)	20,399	9,481	8,865	428	7	-	-	5,001	828	45,007
NY-F (Capital)	-	2,492	15,819	-	-	-	-	55	153	18,520
NY-GHI (Southeast)	-	318	14,504	-	-	-	-	-	533	15,355
NY-J (NY City)	-	5,694	28,357	-	-	-	-	-	166	34,217
NY-K (Long Island)	-	-	10,992	-	-	5	1	-	752	11,750
2020 Total All Zones	**23,713**	**32,885**	**83,767**	**3,008**	**-**	**4**	**1**	**6,458**	**3,264**	**153,100**
NY-AB (West)	4,126	14,882	1,749	2,623	-	-	-	1,077	828	25,285
NY-CDE (Cent North)	19,586	9,481	8,791	385	-	-	-	5,326	829	44,399
NY-F (Capital)	-	2,509	16,557	-	-	-	-	55	154	19,275
NY-GHI (Southeast)	-	318	17,568	-	-	-	-	-	534	18,420
NY-J (NY City)	-	5,694	28,239	-	-	-	-	-	165	34,099
NY-K (Long Island)	-	-	10,863	-	-	4	1	-	754	11,622
2021 Total All Zones	**24,555**	**32,856**	**87,699**	**2,814**	**10**	**3**	**1**	**7,145**	**3,310**	**158,392**
NY-AB (West)	4,151	14,875	1,678	2,442	-	-	-	1,315	828	25,288
NY-CDE (Cent North)	20,405	9,481	8,574	373	10	-	-	5,775	858	45,475
NY-F (Capital)	-	2,488	15,099	-	-	-	-	55	166	17,808
NY-GHI (Southeast)	-	318	20,139	-	-	-	-	-	532	20,990
NY-J (NY City)	-	5,694	29,431	-	-	0	-	-	170	35,295
NY-K (Long Island)	-	-	12,777	-	-	2	1	-	756	13,537
2022 Total All Zones	**24,010**	**32,860**	**88,778**	**2,397**	**-**	**2**	**0**	**7,675**	**3,312**	**159,036**
NY-AB (West)	4,475	14,877	1,619	2,034	-	-	-	1,539	826	25,370
NY-CDE (Cent North)	19,535	9,481	8,381	363	-	-	-	6,081	864	44,705
NY-F (Capital)	-	2,490	14,662	-	-	-	-	55	166	17,373
NY-GHI (Southeast)	-	318	20,076	-	-	-	-	-	532	20,927
NY-J (NY City)	-	5,694	31,337	-	-	-	-	-	169	37,199
NY-K (Long Island)	-	-	12,704	-	-	2	0	-	755	13,461
2023 Total All Zones	**24,510**	**32,914**	**88,475**	**2,655**	**6**	**5**	**1**	**8,193**	**3,386**	**160,146**
NY-AB (West)	4,114	14,884	1,598	2,290	-	-	-	1,536	827	25,249
NY-CDE (Cent North)	20,396	9,481	8,259	365	6	-	-	6,602	937	46,046
NY-F (Capital)	-	2,536	14,526	-	-	-	-	55	166	17,283
NY-GHI (Southeast)	-	318	20,023	-	-	-	-	-	533	20,873
NY-J (NY City)	-	5,694	31,381	-	-	-	-	-	165	37,240
NY-K (Long Island)	-	-	12,689	-	-	5	1	-	759	13,454
2024 Total All Zones	**23,752**	**32,972**	**88,971**	**2,799**	**-**	**1**	**0**	**9,123**	**3,399**	**161,017**
NY-AB (West)	4,162	14,887	1,584	2,432	-	-	-	1,544	825	25,435
NY-CDE (Cent North)	19,590	9,481	8,156	367	-	-	-	6,915	950	45,459
NY-F (Capital)	-	2,592	14,025	-	-	-	-	55	166	16,839
NY-GHI (Southeast)	-	318	19,786	-	-	-	-	-	534	20,638
NY-J (NY City)	-	5,694	30,534	-	-	-	-	-	165	36,393
NY-K (Long Island)	-	-	14,885	-	-	1	0	609	759	16,253
2025 Total All Zones	**24,870**	**32,984**	**91,211**	**2,341**	**9**	**0**	**-**	**9,158**	**3,542**	**164,115**
NY-AB (West)	4,473	14,896	1,567	1,982	-	-	-	1,539	819	25,277
NY-CDE (Cent North)	20,397	9,481	7,945	359	9	-	-	6,900	1,093	46,184
NY-F (Capital)	-	2,595	12,403	-	-	-	-	55	166	15,218
NY-GHI (Southeast)	-	318	18,995	-	-	-	-	-	532	19,846
NY-J (NY City)	-	5,694	33,144	-	-	-	-	55	165	39,058
NY-K (Long Island)	-	-	17,157	-	-	0	-	608	767	18,533

Scenario 12 - IPEC OOS Hi Wind	Nuclear	Hydro&PS	NatGas	Coal	Oil 6	Oil 2	Ker	Wind	Other (Wood, Refuse, Bio, PV, DR/LaaR)	Total
2015 Total All Zones	**39,975**	**27,273**	**67,425**	**5,376**	**-**	**6**	**1**	**5,865**	**3,146**	**149,066**
NY-AB (West)	4,151	14,891	1,928	4,924	-	-	-	1,072	828	27,793
NY-CDE (Cent North)	20,408	9,481	9,427	452	-	-	-	4,737	818	45,322
NY-F (Capital)	-	2,583	17,839	-	-	-	-	55	153	20,630
NY-GHI (Southeast)	15,417	318	746	-	-	-	-	-	535	17,016
NY-J (NY City)	-	-	25,909	-	-	-	-	-	54	25,964
NY-K (Long Island)	-	-	11,576	-	-	6	1	-	758	12,342
2016 Total All Zones	**24,074**	**27,303**	**80,053**	**5,906**	**12**	**30**	**4**	**5,884**	**3,331**	**146,597**
NY-AB (West)	4,487	14,897	2,177	5,436	-	-	-	1,077	837	28,910
NY-CDE (Cent North)	19,587	9,481	10,219	470	12	-	-	4,752	825	45,347
NY-F (Capital)	-	2,608	19,960	-	-	-	-	55	154	22,778
NY-GHI (Southeast)	-	318	5,350	-	-	1	-	-	550	6,218
NY-J (NY City)	-	-	29,916	-	-	2	-	-	199	30,117
NY-K (Long Island)	-	-	12,430	-	-	28	4	-	766	13,228
2017 Total All Zones	**24,519**	**27,352**	**80,283**	**5,444**	**31**	**17**	**3**	**6,121**	**3,301**	**147,071**
NY-AB (West)	4,113	14,894	2,058	4,987	-	-	-	1,071	835	27,957
NY-CDE (Cent North)	20,407	9,481	9,791	457	31	-	-	4,994	824	45,985
NY-F (Capital)	-	2,659	19,312	-	-	-	-	55	153	22,179
NY-GHI (Southeast)	-	318	6,995	-	-	0	-	-	542	7,855
NY-J (NY City)	-	-	30,257	-	-	1	-	-	188	30,446
NY-K (Long Island)	-	-	11,870	-	-	16	3	-	759	12,648
2018 Total All Zones	**23,681**	**32,847**	**80,128**	**4,087**	**-**	**4**	**1**	**7,265**	**3,263**	**151,277**
NY-AB (West)	4,149	14,872	1,749	3,664	-	-	-	1,459	825	26,719
NY-CDE (Cent North)	19,531	9,481	8,765	423	-	-	-	5,731	822	44,753
NY-F (Capital)	-	2,482	15,953	-	-	-	-	75	153	18,663
NY-GHI (Southeast)	-	318	14,526	-	-	-	-	-	537	15,381
NY-J (NY City)	-	5,694	28,267	-	-	-	-	-	172	34,133
NY-K (Long Island)	-	-	10,867	-	-	4	1	-	754	11,627
2019 Total All Zones	**24,873**	**32,869**	**78,831**	**3,954**	**4**	**5**	**1**	**8,419**	**3,261**	**152,215**
NY-AB (West)	4,474	14,877	1,746	3,530	-	-	-	1,850	830	27,308
NY-CDE (Cent North)	20,399	9,481	8,781	424	4	-	-	6,475	826	46,389
NY-F (Capital)	-	2,498	15,369	-	-	-	-	95	153	18,116
NY-GHI (Southeast)	-	318	14,316	-	-	-	-	-	533	15,167
NY-J (NY City)	-	5,694	27,694	-	-	0	-	-	166	33,554
NY-K (Long Island)	-	-	10,924	-	-	5	1	-	752	11,682
2020 Total All Zones	**23,713**	**32,896**	**81,470**	**2,854**	**-**	**4**	**1**	**9,907**	**3,260**	**154,105**
NY-AB (West)	4,126	14,885	1,693	2,475	-	-	-	2,248	824	26,252
NY-CDE (Cent North)	19,586	9,481	8,606	379	-	-	-	7,544	828	46,423
NY-F (Capital)	-	2,519	15,642	-	-	-	-	115	154	18,429
NY-GHI (Southeast)	-	318	17,243	-	-	-	-	-	534	18,096
NY-J (NY City)	-	5,694	27,507	-	-	-	-	-	165	33,366
NY-K (Long Island)	-	-	10,779	-	-	4	1	-	754	11,539
2021 Total All Zones	**24,555**	**32,878**	**84,675**	**2,635**	**10**	**2**	**1**	**11,740**	**3,302**	**159,798**
NY-AB (West)	4,151	14,878	1,630	2,273	-	-	-	2,875	824	26,629
NY-CDE (Cent North)	20,405	9,481	8,367	362	10	-	-	8,730	855	48,210
NY-F (Capital)	-	2,507	13,854	-	-	-	-	135	165	16,662
NY-GHI (Southeast)	-	318	19,729	-	-	-	-	-	532	20,580
NY-J (NY City)	-	5,694	28,417	-	-	-	-	-	170	34,281
NY-K (Long Island)	-	-	12,677	-	-	2	1	-	756	13,436
2022 Total All Zones	**24,010**	**32,899**	**85,011**	**1,976**	**-**	**2**	**1**	**13,416**	**3,302**	**160,616**
NY-AB (West)	4,475	14,887	1,565	1,624	-	-	-	3,488	820	26,859
NY-CDE (Cent North)	19,535	9,481	8,134	352	-	-	-	9,773	860	48,134
NY-F (Capital)	-	2,520	13,211	-	-	-	-	155	166	16,051
NY-GHI (Southeast)	-	318	19,467	-	-	-	-	-	532	20,317
NY-J (NY City)	-	5,694	30,070	-	-	-	-	-	168	35,932
NY-K (Long Island)	-	-	12,565	-	-	2	1	-	756	13,324
2023 Total All Zones	**24,510**	**32,944**	**84,127**	**2,194**	**6**	**4**	**1**	**15,052**	**3,371**	**162,210**
NY-AB (West)	4,114	14,888	1,535	1,844	-	-	-	3,864	818	27,064
NY-CDE (Cent North)	20,396	9,481	7,930	350	6	-	-	11,013	930	50,106
NY-F (Capital)	-	2,563	12,980	-	-	-	-	174	166	15,883
NY-GHI (Southeast)	-	318	19,388	-	-	-	-	-	532	20,238
NY-J (NY City)	-	5,694	29,748	-	-	-	-	-	165	35,608
NY-K (Long Island)	-	-	12,547	-	-	4	1	-	759	13,311
2024 Total All Zones	**23,752**	**33,008**	**83,737**	**2,414**	**-**	**1**	**0**	**17,167**	**3,376**	**163,455**
NY-AB (West)	4,162	14,889	1,523	2,058	-	-	-	4,275	814	27,722
NY-CDE (Cent North)	19,590	9,481	7,861	356	-	-	-	12,088	939	50,313
NY-F (Capital)	-	2,625	11,970	-	-	-	-	195	166	14,956
NY-GHI (Southeast)	-	318	18,815	-	-	-	-	-	534	19,667
NY-J (NY City)	-	5,694	28,945	-	-	-	-	-	165	34,804
NY-K (Long Island)	-	-	14,624	-	-	1	0	609	759	15,993
2025 Total All Zones	**24,870**	**33,039**	**85,350**	**1,940**	**3**	**0**	**-**	**18,350**	**3,504**	**167,056**
NY-AB (West)	4,473	14,901	1,503	1,596	-	-	-	4,659	804	27,935
NY-CDE (Cent North)	20,397	9,481	7,606	344	3	-	-	12,812	1,070	51,714
NY-F (Capital)	-	2,645	10,780	-	-	-	-	215	166	13,806
NY-GHI (Southeast)	-	318	18,004	-	-	-	-	-	532	18,854
NY-J (NY City)	-	5,694	30,671	-	-	-	-	55	165	36,585
NY-K (Long Island)	-	-	16,787	-	-	0	-	608	767	18,162

Scenario 13 - IPEC OOS HI EE		Nuclear	Hydro&PS	NatGas	Coal	Oil 6	Oil 2	Ker	Wind	Other (Wood, Refuse, Bio, PV, DR/LaaR)	Total
	2015 Total All Zones	**39,975**	**27,387**	**63,851**	**4,774**	**-**	**3**	**0**	**5,864**	**3,092**	**144,948**
NY-AB (West)		4,151	14,903	1,771	4,349	-	-	-	1,072	812	27,058
NY-CDE (Cent North)		20,408	9,481	8,915	426	-	-	-	4,737	805	44,772
NY-F (Capital)		-	2,686	16,306	-	-	-	-	55	152	19,199
NY-GHI (Southeast)		15,417	318	374	-	-	-	-	-	533	16,642
NY-J (NY City)		-	-	25,830	-	-	-	-	-	39	25,869
NY-K (Long Island)		-	-	10,654	-	-	3	0	-	751	11,409
	2016 Total All Zones	**24,074**	**27,383**	**76,738**	**5,221**	**-**	**17**	**3**	**5,884**	**3,275**	**142,594**
NY-AB (West)		4,487	14,908	1,977	4,786	-	-	-	1,077	821	28,057
NY-CDE (Cent North)		19,587	9,481	9,621	435	-	-	-	4,752	814	44,690
NY-F (Capital)		-	2,675	18,524	-	-	-	-	55	154	21,409
NY-GHI (Southeast)		-	318	4,751	-	-	0	-	-	543	5,612
NY-J (NY City)		-	-	30,544	-	-	1	-	-	184	30,729
NY-K (Long Island)		-	-	11,321	-	-	15	3	-	758	12,098
	2017 Total All Zones	**24,519**	**27,416**	**76,645**	**4,548**	**3**	**7**	**1**	**6,120**	**3,271**	**142,532**
NY-AB (West)		4,113	14,904	1,881	4,119	-	-	-	1,071	824	26,911
NY-CDE (Cent North)		20,407	9,481	9,241	430	3	-	-	4,994	816	45,372
NY-F (Capital)		-	2,714	17,716	-	-	-	-	55	153	20,638
NY-GHI (Southeast)		-	318	6,322	-	-	0	-	-	540	7,181
NY-J (NY City)		-	-	30,573	-	-	-	-	-	181	30,754
NY-K (Long Island)		-	-	10,912	-	-	7	1	-	756	11,677
	2018 Total All Zones	**23,681**	**32,856**	**75,392**	**3,637**	**-**	**3**	**1**	**6,122**	**3,236**	**144,927**
NY-AB (West)		4,149	14,874	1,665	3,229	-	-	-	1,071	816	25,805
NY-CDE (Cent North)		19,531	9,481	8,484	408	-	-	-	4,996	816	43,715
NY-F (Capital)		-	2,489	14,666	-	-	-	-	55	153	17,363
NY-GHI (Southeast)		-	318	14,038	-	-	-	-	-	533	14,890
NY-J (NY City)		-	5,694	26,292	-	-	-	-	-	165	32,151
NY-K (Long Island)		-	-	10,248	-	-	3	1	-	752	11,003
	2019 Total All Zones	**24,873**	**32,847**	**75,009**	**3,647**	**-**	**2**	**-**	**6,128**	**3,253**	**145,758**
NY-AB (West)		4,474	14,875	1,689	3,229	-	-	-	1,072	827	26,166
NY-CDE (Cent North)		20,399	9,481	8,603	418	-	-	-	5,001	824	44,726
NY-F (Capital)		-	2,479	14,343	-	-	-	-	55	153	17,030
NY-GHI (Southeast)		-	318	13,876	-	-	-	-	-	533	14,727
NY-J (NY City)		-	5,694	26,116	-	-	-	-	-	165	31,975
NY-K (Long Island)		-	-	10,382	-	-	2	-	-	751	11,135
	2020 Total All Zones	**23,713**	**32,821**	**78,760**	**2,659**	**-**	**2**	**0**	**6,458**	**3,257**	**147,670**
NY-AB (West)		4,126	14,876	1,665	2,284	-	-	-	1,077	824	24,852
NY-CDE (Cent North)		19,586	9,481	8,511	375	-	-	-	5,326	828	44,107
NY-F (Capital)		-	2,452	15,006	-	-	-	-	55	154	17,667
NY-GHI (Southeast)		-	318	16,940	-	-	-	-	-	534	17,792
NY-J (NY City)		-	5,694	26,384	-	-	-	-	-	165	32,243
NY-K (Long Island)		-	-	10,254	-	-	2	0	-	753	11,009
	2021 Total All Zones	**24,555**	**32,836**	**83,106**	**2,529**	**-**	**1**	**0**	**7,145**	**3,300**	**153,472**
NY-AB (West)		4,151	14,879	1,627	2,165	-	-	-	1,315	825	24,960
NY-CDE (Cent North)		20,405	9,481	8,370	364	-	-	-	5,775	856	45,251
NY-F (Capital)		-	2,465	13,640	-	-	-	-	55	165	16,326
NY-GHI (Southeast)		-	318	19,513	-	-	-	-	-	532	20,363
NY-J (NY City)		-	5,694	27,679	-	-	-	-	-	166	33,539
NY-K (Long Island)		-	-	12,276	-	-	1	0	-	756	13,034
	2022 Total All Zones	**24,010**	**32,890**	**84,340**	**1,997**	**-**	**1**	**-**	**7,674**	**3,303**	**154,215**
NY-AB (West)		4,475	14,886	1,573	1,644	-	-	-	1,538	823	24,941
NY-CDE (Cent North)		19,535	9,481	8,197	353	-	-	-	6,081	863	44,509
NY-F (Capital)		-	2,510	13,339	-	-	-	-	55	166	16,070
NY-GHI (Southeast)		-	318	19,377	-	-	-	-	-	532	20,227
NY-J (NY City)		-	5,694	29,681	-	-	-	-	-	165	35,540
NY-K (Long Island)		-	-	12,173	-	-	1	-	-	754	12,928
	2023 Total All Zones	**24,510**	**32,908**	**84,153**	**2,236**	**3**	**1**	**0**	**8,193**	**3,379**	**155,384**
NY-AB (West)		4,114	14,886	1,547	1,879	-	-	-	1,536	824	24,786
NY-CDE (Cent North)		20,396	9,481	8,071	357	3	-	-	6,602	935	45,845
NY-F (Capital)		-	2,530	13,405	-	-	-	-	55	166	16,155
NY-GHI (Southeast)		-	318	19,318	-	-	-	-	-	532	20,169
NY-J (NY City)		-	5,694	29,647	-	-	-	-	-	165	35,505
NY-K (Long Island)		-	-	12,165	-	-	1	0	-	757	12,924
	2024 Total All Zones	**23,752**	**32,940**	**84,515**	**2,410**	**-**	**0**	**-**	**9,122**	**3,393**	**156,133**
NY-AB (West)		4,162	14,885	1,545	2,049	-	-	-	1,544	822	25,006
NY-CDE (Cent North)		19,590	9,481	8,016	362	-	-	-	6,914	948	45,311
NY-F (Capital)		-	2,562	12,605	-	-	-	-	55	166	15,388
NY-GHI (Southeast)		-	318	18,994	-	-	-	-	-	534	19,845
NY-J (NY City)		-	5,694	28,960	-	-	-	-	-	165	34,819
NY-K (Long Island)		-	-	14,396	-	-	0	-	609	758	15,763
	2025 Total All Zones	**24,870**	**32,913**	**86,710**	**2,025**	**-**	**0**	**-**	**9,158**	**3,532**	**159,207**
NY-AB (West)		4,473	14,888	1,523	1,674	-	-	-	1,539	814	24,911
NY-CDE (Cent North)		20,397	9,481	7,743	351	-	-	-	6,900	1,088	45,960
NY-F (Capital)		-	2,532	11,298	-	-	-	-	55	166	14,051
NY-GHI (Southeast)		-	318	18,198	-	-	-	-	-	532	19,049
NY-J (NY City)		-	5,694	31,306	-	-	-	-	55	165	37,221
NY-K (Long Island)		-	-	16,641	-	-	0	-	608	767	18,016

Scenario 14 - IPEC OOS Hi EE, Wind, PV	Nuclear	Hydro&PS	NatGas	Coal	Oil 6	Oil 2	Ker	Wind	Other (Wood, Refuse, Bio, PV, DR/LaaR)	Total
2015 Total All Zones	**39,975**	**27,317**	**62,171**	**4,913**	**-**	**4**	**0**	**5,865**	**4,035**	**144,281**
NY-AB (West)	4,151	14,895	1,787	4,485	-	-	-	1,072	1,008	27,397
NY-CDE (Cent North)	20,408	9,481	8,924	428	-	-	-	4,737	1,001	44,978
NY-F (Capital)	-	2,624	16,488	-	-	-	-	55	348	19,515
NY-GHI (Southeast)	15,417	318	415	-	-	-	-	-	627	16,776
NY-J (NY City)	-	-	23,784	-	-	-	-	-	137	23,921
NY-K (Long Island)	-	-	10,774	-	-	4	0	-	914	11,693
2016 Total All Zones	**24,074**	**27,298**	**77,256**	**520**	**-**	**20**	**3**	**5,884**	**4,708**	**139,765**
NY-AB (West)	4,487	14,899	2,223	64	-	-	-	1,077	1,136	23,887
NY-CDE (Cent North)	19,587	9,481	10,140	456	-	-	-	4,752	1,124	45,540
NY-F (Capital)	-	2,600	19,462	-	-	-	-	55	461	22,578
NY-GHI (Southeast)	-	318	5,133	-	-	1	-	-	688	6,140
NY-J (NY City)	-	-	28,441	-	-	1	-	-	328	28,771
NY-K (Long Island)	-	-	11,856	-	-	18	3	-	971	12,849
2017 Total All Zones	**24,519**	**27,307**	**76,749**	**493**	**3**	**9**	**1**	**6,121**	**5,167**	**140,369**
NY-AB (West)	4,113	14,894	2,067	52	-	-	-	1,071	1,245	23,441
NY-CDE (Cent North)	20,407	9,481	9,599	441	3	-	-	4,994	1,235	46,160
NY-F (Capital)	-	2,615	18,495	-	-	-	-	55	569	21,734
NY-GHI (Southeast)	-	318	6,676	-	-	0	-	-	729	7,723
NY-J (NY City)	-	-	28,678	-	-	0	-	-	373	29,052
NY-K (Long Island)	-	-	11,234	-	-	8	1	-	1,015	12,259
2018 Total All Zones	**23,681**	**32,775**	**74,950**	**435**	**-**	**3**	**1**	**7,265**	**5,577**	**144,686**
NY-AB (West)	4,149	14,864	1,739	26	-	-	-	1,459	1,339	23,577
NY-CDE (Cent North)	19,531	9,481	8,554	409	-	-	-	5,731	1,338	45,043
NY-F (Capital)	-	2,418	14,376	-	-	-	-	75	678	17,547
NY-GHI (Southeast)	-	318	13,992	-	-	-	-	-	768	15,078
NY-J (NY City)	-	5,694	26,132	-	-	-	-	-	400	32,226
NY-K (Long Island)	-	-	10,157	-	-	3	1	-	1,054	11,215
2019 Total All Zones	**24,873**	**32,760**	**73,570**	**434**	**-**	**2**	**-**	**8,419**	**6,057**	**146,114**
NY-AB (West)	4,474	14,866	1,726	24	-	-	-	1,850	1,457	24,397
NY-CDE (Cent North)	20,399	9,481	8,566	410	-	-	-	6,475	1,455	46,785
NY-F (Capital)	-	2,401	13,577	-	-	-	-	95	786	16,859
NY-GHI (Southeast)	-	318	13,809	-	-	-	-	-	814	14,941
NY-J (NY City)	-	5,694	25,713	-	-	-	-	-	446	31,853
NY-K (Long Island)	-	-	10,180	-	-	2	-	-	1,098	11,279
2020 Total All Zones	**23,713**	**32,726**	**75,265**	**371**	**-**	**1**	**-**	**9,907**	**6,535**	**148,518**
NY-AB (West)	4,126	14,855	1,669	4	-	-	-	2,248	1,563	24,465
NY-CDE (Cent North)	19,586	9,481	8,340	367	-	-	-	7,544	1,569	46,887
NY-F (Capital)	-	2,378	13,501	-	-	-	-	115	898	16,893
NY-GHI (Southeast)	-	318	16,397	-	-	-	-	-	863	17,579
NY-J (NY City)	-	5,694	25,337	-	-	-	-	-	494	31,525
NY-K (Long Island)	-	-	10,021	-	-	1	-	-	1,148	11,170
2021 Total All Zones	**24,555**	**32,730**	**78,518**	**353**	**-**	**1**	**0**	**11,740**	**7,051**	**154,949**
NY-AB (West)	4,151	14,854	1,618	0	-	-	-	2,875	1,674	25,171
NY-CDE (Cent North)	20,405	9,481	8,062	352	-	-	-	8,730	1,708	48,737
NY-F (Capital)	-	2,383	12,000	-	-	-	-	135	1,022	15,540
NY-GHI (Southeast)	-	318	18,748	-	-	-	-	-	909	19,975
NY-J (NY City)	-	5,694	26,177	-	-	-	-	-	543	32,414
NY-K (Long Island)	-	-	11,913	-	-	1	0	-	1,196	13,111
2022 Total All Zones	**24,012**	**32,749**	**78,202**	**332**	**-**	**1**	**-**	**13,415**	**7,517**	**156,229**
NY-AB (West)	4,475	14,853	1,553	-	-	-	-	3,488	1,777	26,146
NY-CDE (Cent North)	19,537	9,481	7,823	332	-	-	-	9,773	1,822	48,767
NY-F (Capital)	-	2,402	11,219	-	-	-	-	155	1,132	14,908
NY-GHI (Southeast)	-	318	18,183	-	-	-	-	-	957	19,458
NY-J (NY City)	-	5,694	27,668	-	-	-	-	-	589	33,952
NY-K (Long Island)	-	-	11,756	-	-	1	-	-	1,241	12,998
2023 Total All Zones	**24,510**	**32,785**	**77,277**	**339**	**-**	**1**	**0**	**15,051**	**8,050**	**158,012**
NY-AB (West)	4,114	14,859	1,529	1	-	-	-	3,864	1,883	26,250
NY-CDE (Cent North)	20,396	9,481	7,658	338	-	-	-	11,012	2,000	50,885
NY-F (Capital)	-	2,432	10,896	-	-	-	-	174	1,241	14,743
NY-GHI (Southeast)	-	318	18,336	-	-	-	-	-	1,003	19,658
NY-J (NY City)	-	5,694	27,159	-	-	-	-	-	636	33,489
NY-K (Long Island)	-	-	11,699	-	-	1	0	-	1,288	12,988
2024 Total All Zones	**23,752**	**32,810**	**77,003**	**341**	**-**	**-**	**-**	**17,165**	**8,036**	**159,106**
NY-AB (West)	4,162	14,858	1,519	-	-	-	-	4,275	1,871	26,686
NY-CDE (Cent North)	19,590	9,481	7,565	341	-	-	-	12,086	2,002	51,065
NY-F (Capital)	-	2,459	10,269	-	-	-	-	195	1,238	14,161
NY-GHI (Southeast)	-	318	17,548	-	-	-	-	-	1,003	18,869
NY-J (NY City)	-	5,694	26,267	-	-	-	-	-	635	32,595
NY-K (Long Island)	-	-	13,835	-	-	-	-	609	1,287	15,731
2025 Total All Zones	**24,870**	**32,804**	**78,012**	**330**	**-**	**-**	**-**	**18,341**	**8,152**	**162,510**
NY-AB (West)	4,473	14,856	1,479	-	-	-	-	4,657	1,862	27,327
NY-CDE (Cent North)	20,397	9,481	7,356	330	-	-	-	12,806	2,129	52,499
NY-F (Capital)	-	2,455	9,037	-	-	-	-	215	1,238	12,945
NY-GHI (Southeast)	-	318	16,331	-	-	-	-	-	1,002	17,652
NY-J (NY City)	-	5,694	27,761	-	-	-	-	55	634	34,144
NY-K (Long Island)	-	-	16,049	-	-	-	-	608	1,285	17,942

Scenario 31 - IPEC 2 Seq. Years base	Nuclear	Hydro&PS	NatGas	Coal	Oil 6	Oil 2	Ker	Wind	Other (Wood, Refuse, Bio, PV, DR/LaaR)	Total
2015 Total All Zones	**39,975**	**27,273**	**67,425**	**5,376**	**-**	**6**	**1**	**5,865**	**3,146**	**149,066**
NY-AB (West)	4,151	14,891	1,928	4,924	-	-	-	1,072	828	27,793
NY-CDE (Cent North)	20,408	9,481	9,427	452	-	-	-	4,737	818	45,322
NY-F (Capital)	-	2,583	17,839	-	-	-	-	55	153	20,630
NY-GHI (Southeast)	15,417	318	746	-	-	-	-	-	535	17,016
NY-J (NY City)	-	-	25,909	-	-	-	-	-	54	25,964
NY-K (Long Island)	-	-	11,576	-	-	6	1	-	758	12,342
2016 Total All Zones	**37,299**	**27,303**	**72,705**	**5,019**	**6**	**25**	**4**	**5,884**	**3,317**	**151,562**
NY-AB (West)	4,487	14,897	1,916	4,578	-	-	-	1,077	832	27,787
NY-CDE (Cent North)	19,587	9,481	9,344	442	6	-	-	4,752	823	44,434
NY-F (Capital)	-	2,608	17,842	-	-	-	-	55	153	20,659
NY-GHI (Southeast)	13,224	318	4,652	-	-	0	-	-	545	18,740
NY-J (NY City)	-	-	27,293	-	-	2	-	-	198	27,493
NY-K (Long Island)	-	-	11,658	-	-	23	4	-	765	12,450
2017 Total All Zones	**31,062**	**27,352**	**76,578**	**4,912**	**24**	**16**	**2**	**6,121**	**3,298**	**149,364**
NY-AB (West)	4,113	14,894	1,958	4,468	-	-	-	1,071	833	27,337
NY-CDE (Cent North)	20,407	9,481	9,446	444	24	-	-	4,994	823	45,618
NY-F (Capital)	-	2,659	18,165	-	-	-	-	55	153	21,032
NY-GHI (Southeast)	6,543	318	6,603	-	-	0	-	-	541	14,006
NY-J (NY City)	-	-	28,913	-	-	1	-	-	188	29,102
NY-K (Long Island)	-	-	11,493	-	-	15	2	-	759	12,270
2018 Total All Zones	**31,110**	**32,847**	**75,703**	**3,758**	**-**	**3**	**1**	**6,123**	**3,256**	**152,800**
NY-AB (West)	4,149	14,870	1,679	3,346	-	-	-	1,071	824	25,940
NY-CDE (Cent North)	19,531	9,481	8,455	412	-	-	-	4,996	823	43,698
NY-F (Capital)	-	2,483	14,384	-	-	-	-	55	153	17,075
NY-GHI (Southeast)	7,429	318	13,851	-	-	-	-	-	534	22,132
NY-J (NY City)	-	5,694	26,636	-	-	-	-	-	169	32,499
NY-K (Long Island)	-	-	10,698	-	-	3	1	-	753	11,456
2019 Total All Zones	**39,672**	**32,863**	**70,085**	**3,235**	**-**	**4**	**1**	**6,128**	**3,254**	**155,242**
NY-AB (West)	4,474	14,878	1,606	2,834	-	-	-	1,072	827	25,691
NY-CDE (Cent North)	20,399	9,481	8,140	401	-	-	-	5,001	825	44,246
NY-F (Capital)	-	2,492	12,126	-	-	-	-	55	153	14,827
NY-GHI (Southeast)	14,799	318	12,715	-	-	-	-	-	532	28,365
NY-J (NY City)	-	5,694	24,860	-	-	-	-	-	166	30,720
NY-K (Long Island)	-	-	10,637	-	-	4	1	-	751	11,393
2020 Total All Zones	**38,523**	**32,885**	**73,529**	**2,223**	**-**	**3**	**1**	**6,458**	**3,254**	**156,876**
NY-AB (West)	4,126	14,882	1,589	1,866	-	-	-	1,077	821	24,361
NY-CDE (Cent North)	19,586	9,481	8,012	357	-	-	-	5,326	826	43,588
NY-F (Capital)	-	2,509	12,721	-	-	-	-	55	153	15,439
NY-GHI (Southeast)	14,810	318	15,443	-	-	-	-	-	533	31,105
NY-J (NY City)	-	5,694	25,237	-	-	-	-	-	165	31,096
NY-K (Long Island)	-	-	10,527	-	-	3	1	-	754	11,286
2021 Total All Zones	**39,351**	**32,856**	**77,588**	**2,100**	**9**	**2**	**1**	**7,145**	**3,301**	**162,353**
NY-AB (West)	4,151	14,875	1,574	1,755	-	-	-	1,315	822	24,492
NY-CDE (Cent North)	20,405	9,481	7,859	345	9	-	-	5,775	855	44,729
NY-F (Capital)	-	2,488	11,223	-	-	-	-	55	165	13,931
NY-GHI (Southeast)	14,795	318	18,271	-	-	-	-	-	532	33,917
NY-J (NY City)	-	5,694	26,230	-	-	-	-	-	170	32,094
NY-K (Long Island)	-	-	12,430	-	-	2	1	-	756	13,189
2022 Total All Zones	**38,767**	**32,860**	**78,631**	**1,684**	**-**	**2**	**1**	**7,675**	**3,302**	**162,922**
NY-AB (West)	4,475	14,877	1,517	1,350	-	-	-	1,539	818	24,576
NY-CDE (Cent North)	19,535	9,481	7,708	333	-	-	-	6,081	863	44,000
NY-F (Capital)	-	2,490	11,066	-	-	-	-	55	165	13,777
NY-GHI (Southeast)	14,757	318	18,095	-	-	-	-	-	532	33,702
NY-J (NY City)	-	5,694	27,908	-	-	-	-	-	168	33,771
NY-K (Long Island)	-	-	12,338	-	-	2	1	-	755	13,096
2023 Total All Zones	**39,299**	**32,914**	**78,619**	**1,802**	**-**	**3**	**1**	**8,193**	**3,375**	**164,207**
NY-AB (West)	4,114	14,884	1,507	1,464	-	-	-	1,536	819	24,325
NY-CDE (Cent North)	20,396	9,481	7,623	338	-	-	-	6,602	934	45,374
NY-F (Capital)	-	2,536	11,073	-	-	-	-	55	165	13,830
NY-GHI (Southeast)	14,789	318	18,124	-	-	-	-	-	532	33,764
NY-J (NY City)	-	5,694	27,949	-	-	-	-	-	166	33,809
NY-K (Long Island)	-	-	12,342	-	-	3	1	-	759	13,105
2024 Total All Zones	**38,556**	**32,972**	**79,025**	**1,986**	**-**	**1**	**0**	**9,123**	**3,389**	**165,050**
NY-AB (West)	4,162	14,887	1,508	1,639	-	-	-	1,544	819	24,559
NY-CDE (Cent North)	19,590	9,481	7,608	347	-	-	-	6,915	947	44,888
NY-F (Capital)	-	2,592	10,489	-	-	-	-	55	166	13,302
NY-GHI (Southeast)	14,803	318	17,609	-	-	-	-	-	533	33,264
NY-J (NY City)	-	5,694	27,439	-	-	-	-	-	165	33,299
NY-K (Long Island)	-	-	14,371	-	-	1	0	609	759	15,739
2025 Total All Zones	**39,618**	**32,984**	**80,930**	**1,824**	**-**	**0**	**-**	**9,158**	**3,524**	**168,038**
NY-AB (West)	4,473	14,896	1,495	1,485	-	-	-	1,539	810	24,698
NY-CDE (Cent North)	20,397	9,481	7,442	340	-	-	-	6,900	1,085	45,644
NY-F (Capital)	-	2,595	9,497	-	-	-	-	55	165	12,313
NY-GHI (Southeast)	14,747	318	16,679	-	-	-	-	-	532	32,277
NY-J (NY City)	-	5,694	29,247	-	-	-	-	55	165	35,161
NY-K (Long Island)	-	-	16,570	-	-	0	-	608	767	17,945

Scenario 32 - IPEC 2 Seq. Years Hi Wind	Nuclear	Hydro&PS	NatGas	Coal	Oil 6	Oil 2	Ker	Wind	Other (Wood, Refuse, Bio, PV, DR/LaaR)	Total
2015 Total All Zones	**39,975**	**27,273**	**67,425**	**5,376**	**-**	**6**	**1**	**5,865**	**3,146**	**149,066**
NY-AB (West)	4,151	14,891	1,928	4,924	-	-	-	1,072	828	27,793
NY-CDE (Cent North)	20,408	9,481	9,427	452	-	-	-	4,737	818	45,322
NY-F (Capital)	-	2,583	17,839	-	-	-	-	55	153	20,630
NY-GHI (Southeast)	15,417	318	746	-	-	-	-	-	535	17,016
NY-J (NY City)	-	-	25,909	-	-	-	-	-	54	25,964
NY-K (Long Island)	-	-	11,576	-	-	6	1	-	758	12,342
2016 Total All Zones	**37,299**	**27,303**	**72,705**	**5,019**	**6**	**25**	**4**	**5,884**	**3,317**	**151,562**
NY-AB (West)	4,487	14,897	1,916	4,578	-	-	-	1,077	832	27,787
NY-CDE (Cent North)	19,587	9,481	9,344	442	6	-	-	4,752	823	44,434
NY-F (Capital)	-	2,608	17,842	-	-	-	-	55	153	20,659
NY-GHI (Southeast)	13,224	318	4,652	-	-	0	-	-	545	18,740
NY-J (NY City)	-	-	27,293	-	-	2	-	-	198	27,493
NY-K (Long Island)	-	-	11,658	-	-	23	4	-	765	12,450
2017 Total All Zones	**31,062**	**27,352**	**76,578**	**4,912**	**24**	**16**	**2**	**6,121**	**3,298**	**149,364**
NY-AB (West)	4,113	14,894	1,958	4,468	-	-	-	1,071	833	27,337
NY-CDE (Cent North)	20,407	9,481	9,446	444	24	-	-	4,994	823	45,618
NY-F (Capital)	-	2,659	18,165	-	-	-	-	55	153	21,032
NY-GHI (Southeast)	6,543	318	6,603	-	-	0	-	-	541	14,006
NY-J (NY City)	-	-	28,913	-	-	1	-	-	188	29,102
NY-K (Long Island)	-	-	11,493	-	-	15	2	-	759	12,270
2018 Total All Zones	**31,110**	**32,847**	**74,940**	**3,698**	**-**	**3**	**1**	**7,265**	**3,251**	**153,115**
NY-AB (West)	4,149	14,872	1,659	3,289	-	-	-	1,459	821	26,251
NY-CDE (Cent North)	19,531	9,481	8,384	409	-	-	-	5,731	821	44,357
NY-F (Capital)	-	2,482	14,154	-	-	-	-	75	153	16,864
NY-GHI (Southeast)	7,429	318	13,727	-	-	-	-	-	534	22,008
NY-J (NY City)	-	5,694	26,350	-	-	-	-	-	169	32,213
NY-K (Long Island)	-	-	10,666	-	-	3	1	-	753	11,424
2019 Total All Zones	**39,672**	**32,869**	**68,495**	**3,140**	**-**	**4**	**1**	**8,419**	**3,248**	**155,847**
NY-AB (West)	4,474	14,877	1,577	2,745	-	-	-	1,850	823	26,346
NY-CDE (Cent North)	20,399	9,481	8,029	395	-	-	-	6,475	823	45,601
NY-F (Capital)	-	2,498	11,521	-	-	-	-	95	153	14,267
NY-GHI (Southeast)	14,799	318	12,297	-	-	-	-	-	532	27,946
NY-J (NY City)	-	5,694	24,489	-	-	-	-	-	166	30,349
NY-K (Long Island)	-	-	10,583	-	-	4	1	-	751	11,338
2020 Total All Zones	**38,523**	**32,896**	**71,288**	**1,956**	**-**	**3**	**1**	**9,907**	**3,249**	**157,823**
NY-AB (West)	4,126	14,885	1,551	1,609	-	-	-	2,248	818	25,237
NY-CDE (Cent North)	19,586	9,481	7,863	347	-	-	-	7,544	825	45,646
NY-F (Capital)	-	2,519	11,762	-	-	-	-	115	153	14,549
NY-GHI (Southeast)	14,810	318	14,885	-	-	-	-	-	533	30,546
NY-J (NY City)	-	5,694	24,754	-	-	-	-	-	165	30,614
NY-K (Long Island)	-	-	10,473	-	-	3	1	-	754	11,232
2021 Total All Zones	**39,351**	**32,878**	**74,602**	**1,847**	**5**	**2**	**1**	**11,740**	**3,290**	**163,716**
NY-AB (West)	4,151	14,878	1,533	1,511	-	-	-	2,875	816	25,763
NY-CDE (Cent North)	20,405	9,481	7,661	336	5	-	-	8,730	851	47,469
NY-F (Capital)	-	2,507	10,219	-	-	-	-	135	165	13,026
NY-GHI (Southeast)	14,795	318	17,346	-	-	-	-	-	532	32,992
NY-J (NY City)	-	5,694	25,520	-	-	-	-	-	170	31,384
NY-K (Long Island)	-	-	12,323	-	-	2	1	-	756	13,082
2022 Total All Zones	**38,767**	**32,899**	**74,631**	**1,472**	**-**	**3**	**1**	**13,416**	**3,289**	**164,479**
NY-AB (West)	4,475	14,887	1,480	1,147	-	-	-	3,488	811	26,289
NY-CDE (Cent North)	19,535	9,481	7,452	325	-	-	-	9,773	858	47,423
NY-F (Capital)	-	2,520	9,660	-	-	-	-	155	165	12,500
NY-GHI (Southeast)	14,757	318	16,901	-	-	-	-	-	532	32,509
NY-J (NY City)	-	5,694	26,888	-	-	-	-	-	168	32,750
NY-K (Long Island)	-	-	12,249	-	-	3	1	-	755	13,008
2023 Total All Zones	**39,299**	**32,944**	**74,116**	**1,521**	**-**	**3**	**1**	**15,052**	**3,356**	**166,293**
NY-AB (West)	4,114	14,888	1,471	1,198	-	-	-	3,865	808	26,344
NY-CDE (Cent North)	20,396	9,481	7,380	323	-	-	-	11,013	927	49,520
NY-F (Capital)	-	2,563	9,513	-	-	-	-	174	165	12,415
NY-GHI (Southeast)	14,789	318	16,917	-	-	-	-	-	531	32,556
NY-J (NY City)	-	5,694	26,612	-	-	-	-	-	166	32,472
NY-K (Long Island)	-	-	12,223	-	-	3	1	-	759	12,987
2024 Total All Zones	**38,556**	**33,008**	**73,978**	**1,548**	**-**	**1**	**0**	**17,167**	**3,361**	**167,618**
NY-AB (West)	4,162	14,889	1,467	1,219	-	-	-	4,276	805	26,817
NY-CDE (Cent North)	19,590	9,481	7,307	329	-	-	-	12,088	934	49,728
NY-F (Capital)	-	2,625	9,166	-	-	-	-	195	165	12,152
NY-GHI (Southeast)	14,803	318	16,006	-	-	-	-	-	532	31,660
NY-J (NY City)	-	5,694	25,923	-	-	-	-	-	165	31,783
NY-K (Long Island)	-	-	14,110	-	-	1	0	609	759	15,479
2025 Total All Zones	**39,618**	**33,039**	**74,956**	**1,594**	**-**	**-**	**-**	**18,346**	**3,485**	**171,038**
NY-AB (West)	4,473	14,901	1,457	1,271	-	-	-	4,659	794	27,555
NY-CDE (Cent North)	20,397	9,481	7,186	323	-	-	-	12,808	1,062	51,257
NY-F (Capital)	-	2,645	8,188	-	-	-	-	215	165	11,214
NY-GHI (Southeast)	14,747	318	14,803	-	-	-	-	-	531	30,400
NY-J (NY City)	-	5,694	27,067	-	-	-	-	55	165	32,981
NY-K (Long Island)	-	-	16,254	-	-	-	-	608	767	17,630

Scenario 33 - IPEC 2 Seq. Years Hi EE	Nuclear	Hydro&PS	NatGas	Coal	Oil 6	Oil 2	Ker	Wind	Other (Wood, Refuse, Bio, PV, DR/LaaR)	Total
2015 Total All Zones	**39,975**	**27,372**	**62,824**	**4,998**	**-**	**4**	**1**	**5,865**	**3,100**	**144,137**
NY-AB (West)	4,151	14,904	1,804	4,569	-	-	-	1,072	812	27,312
NY-CDE (Cent North)	20,408	9,481	8,995	429	-	-	-	4,737	806	44,855
NY-F (Capital)	-	2,668	16,722	-	-	-	-	55	152	19,598
NY-GHI (Southeast)	15,417	318	471	-	-	-	-	-	533	16,739
NY-J (NY City)	-	-	23,949	-	-	-	-	-	44	23,993
NY-K (Long Island)	-	-	10,883	-	-	4	1	-	752	11,640
2016 Total All Zones	**37,299**	**27,384**	**67,847**	**4,183**	**-**	**18**	**3**	**5,884**	**3,269**	**145,886**
NY-AB (West)	4,487	14,904	1,804	3,761	-	-	-	1,077	819	26,852
NY-CDE (Cent North)	19,587	9,481	8,971	422	-	-	-	4,752	812	44,025
NY-F (Capital)	-	2,680	16,583	-	-	-	-	55	153	19,471
NY-GHI (Southeast)	13,224	318	4,210	-	-	0	-	-	541	18,294
NY-J (NY City)	-	-	25,344	-	-	1	-	-	183	25,528
NY-K (Long Island)	-	-	10,935	-	-	17	3	-	761	11,715
2017 Total All Zones	**31,062**	**27,404**	**71,374**	**4,453**	**6**	**9**	**1**	**6,121**	**3,264**	**143,695**
NY-AB (West)	4,113	14,899	1,819	4,029	-	-	-	1,071	822	26,752
NY-CDE (Cent North)	20,407	9,481	9,052	424	6	-	-	4,994	815	45,179
NY-F (Capital)	-	2,706	16,834	-	-	-	-	55	153	19,749
NY-GHI (Southeast)	6,543	318	6,042	-	-	0	-	-	536	13,439
NY-J (NY City)	-	-	26,835	-	-	0	-	-	181	27,017
NY-K (Long Island)	-	-	10,791	-	-	9	1	-	757	11,558
2018 Total All Zones	**31,110**	**32,855**	**70,043**	**3,198**	**-**	**3**	**0**	**6,123**	**3,232**	**146,562**
NY-AB (West)	4,149	14,874	1,600	2,803	-	-	-	1,071	814	25,311
NY-CDE (Cent North)	19,531	9,481	8,140	394	-	-	-	4,996	816	43,359
NY-F (Capital)	-	2,488	12,822	-	-	-	-	55	153	15,518
NY-GHI (Southeast)	7,429	318	13,123	-	-	-	-	-	533	21,402
NY-J (NY City)	-	5,694	24,287	-	-	-	-	-	165	30,147
NY-K (Long Island)	-	-	10,071	-	-	3	0	-	752	10,826
2019 Total All Zones	**39,672**	**32,846**	**64,559**	**2,897**	**-**	**2**	**-**	**6,128**	**3,241**	**149,345**
NY-AB (West)	4,474	14,874	1,550	2,510	-	-	-	1,072	820	25,300
NY-CDE (Cent North)	20,399	9,481	7,880	387	-	-	-	5,001	821	43,968
NY-F (Capital)	-	2,479	10,622	-	-	-	-	55	153	13,309
NY-GHI (Southeast)	14,799	318	11,725	-	-	-	-	-	532	27,374
NY-J (NY City)	-	5,694	22,779	-	-	-	-	-	165	28,638
NY-K (Long Island)	-	-	10,003	-	-	2	-	-	750	10,756
2020 Total All Zones	**38,523**	**32,821**	**68,393**	**1,880**	**-**	**1**	**0**	**6,458**	**3,245**	**151,322**
NY-AB (West)	4,126	14,876	1,531	1,533	-	-	-	1,077	817	23,960
NY-CDE (Cent North)	19,586	9,481	7,811	347	-	-	-	5,326	824	43,375
NY-F (Capital)	-	2,452	11,059	-	-	-	-	55	153	13,720
NY-GHI (Southeast)	14,810	318	14,562	-	-	-	-	-	533	30,223
NY-J (NY City)	-	5,694	23,466	-	-	-	-	-	165	29,326
NY-K (Long Island)	-	-	9,964	-	-	1	0	-	753	10,718
2021 Total All Zones	**39,351**	**32,836**	**72,863**	**1,848**	**-**	**1**	**0**	**7,145**	**3,289**	**157,334**
NY-AB (West)	4,151	14,878	1,526	1,509	-	-	-	1,315	818	24,196
NY-CDE (Cent North)	20,405	9,481	7,669	339	-	-	-	5,775	853	44,520
NY-F (Capital)	-	2,465	9,985	-	-	-	-	55	165	12,670
NY-GHI (Southeast)	14,795	318	17,196	-	-	-	-	-	532	32,841
NY-J (NY City)	-	5,694	24,587	-	-	-	-	-	166	30,447
NY-K (Long Island)	-	-	11,902	-	-	1	0	-	756	12,660
2022 Total All Zones	**38,767**	**32,889**	**73,766**	**1,511**	**-**	**1**	**-**	**7,675**	**3,292**	**157,900**
NY-AB (West)	4,475	14,886	1,483	1,183	-	-	-	1,539	815	24,380
NY-CDE (Cent North)	19,535	9,481	7,559	328	-	-	-	6,081	860	43,843
NY-F (Capital)	-	2,510	9,735	-	-	-	-	55	165	12,466
NY-GHI (Southeast)	14,757	318	17,004	-	-	-	-	-	532	32,611
NY-J (NY City)	-	5,694	26,144	-	-	-	-	-	165	32,004
NY-K (Long Island)	-	-	11,840	-	-	1	-	-	755	12,595
2023 Total All Zones	**39,299**	**32,910**	**73,989**	**1,646**	**-**	**1**	**0**	**8,193**	**3,365**	**159,404**
NY-AB (West)	4,114	14,887	1,479	1,316	-	-	-	1,536	815	24,147
NY-CDE (Cent North)	20,396	9,481	7,479	331	-	-	-	6,602	931	45,220
NY-F (Capital)	-	2,530	9,783	-	-	-	-	55	165	12,533
NY-GHI (Southeast)	14,789	318	17,190	-	-	-	-	-	531	32,829
NY-J (NY City)	-	5,694	26,218	-	-	-	-	-	165	32,077
NY-K (Long Island)	-	-	11,840	-	-	1	0	-	757	12,599
2024 Total All Zones	**38,556**	**32,940**	**74,365**	**1,636**	**-**	**0**	**-**	**9,123**	**3,380**	**159,999**
NY-AB (West)	4,162	14,885	1,479	1,296	-	-	-	1,544	815	24,182
NY-CDE (Cent North)	19,590	9,481	7,449	340	-	-	-	6,915	943	44,717
NY-F (Capital)	-	2,562	9,650	-	-	-	-	55	166	12,433
NY-GHI (Southeast)	14,803	318	16,560	-	-	-	-	-	533	32,215
NY-J (NY City)	-	5,694	25,452	-	-	-	-	-	165	31,311
NY-K (Long Island)	-	-	13,775	-	-	0	-	609	758	15,142
2025 Total All Zones	**39,618**	**32,913**	**76,118**	**1,617**	**-**	**-**	**-**	**9,158**	**3,512**	**162,936**
NY-AB (West)	4,473	14,888	1,475	1,284	-	-	-	1,539	806	24,465
NY-CDE (Cent North)	20,397	9,481	7,317	333	-	-	-	6,900	1,078	45,505
NY-F (Capital)	-	2,532	8,452	-	-	-	-	55	165	11,204
NY-GHI (Southeast)	14,747	318	15,545	-	-	-	-	-	531	31,142
NY-J (NY City)	-	5,694	27,364	-	-	-	-	55	165	33,278
NY-K (Long Island)	-	-	15,965	-	-	-	-	608	767	17,341

Scenario 34 - IPEC 2 Seq. Years Hi EE, Wind, PV	Nuclear	Hydro&PS	NatGas	Coal	Oil 6	Oil 2	Ker	Wind	Other (Wood, Refuse, Bio, PV, DR/LaaR)	Total
2015 Total All Zones	**39,975**	**27,317**	**62,171**	**4,913**	**-**	**4**	**0**	**5,865**	**4,035**	**144,281**
NY-AB (West)	4,151	14,895	1,787	4,485	-	-	-	1,072	1,008	27,397
NY-CDE (Cent North)	20,408	9,481	8,924	428	-	-	-	4,737	1,001	44,978
NY-F (Capital)	-	2,624	16,488	-	-	-	-	55	348	19,515
NY-GHI (Southeast)	15,417	318	415	-	-	-	-	-	627	16,776
NY-J (NY City)	-	-	23,784	-	-	-	-	-	137	23,921
NY-K (Long Island)	-	-	10,774	-	-	4	0	-	914	11,693
2016 Total All Zones	**37,299**	**27,298**	**69,163**	**472**	**-**	**18**	**3**	**5,884**	**4,687**	**144,825**
NY-AB (West)	4,487	14,899	1,953	45	-	-	-	1,077	1,129	23,591
NY-CDE (Cent North)	19,587	9,481	9,228	427	-	-	-	4,752	1,121	44,596
NY-F (Capital)	-	2,600	16,947	-	-	-	-	55	460	20,062
NY-GHI (Southeast)	13,224	318	4,355	-	-	0	-	-	684	18,582
NY-J (NY City)	-	-	25,696	-	-	1	-	-	323	26,020
NY-K (Long Island)	-	-	10,984	-	-	17	3	-	970	11,974
2017 Total All Zones	**31,062**	**27,307**	**72,465**	**472**	**3**	**8**	**1**	**6,121**	**5,153**	**142,594**
NY-AB (West)	4,113	14,894	1,947	42	-	-	-	1,071	1,243	23,309
NY-CDE (Cent North)	20,407	9,481	9,260	430	3	-	-	4,994	1,234	45,809
NY-F (Capital)	-	2,615	17,031	-	-	-	-	55	569	20,270
NY-GHI (Southeast)	6,543	318	6,217	-	-	0	-	-	725	13,804
NY-J (NY City)	-	-	27,179	-	-	0	-	-	368	27,547
NY-K (Long Island)	-	-	10,831	-	-	8	1	-	1,015	11,854
2018 Total All Zones	**31,110**	**32,775**	**69,285**	**415**	**-**	**3**	**0**	**7,265**	**5,572**	**146,425**
NY-AB (West)	4,149	14,864	1,665	19	-	-	-	1,459	1,337	23,493
NY-CDE (Cent North)	19,531	9,481	8,156	396	-	-	-	5,731	1,336	44,631
NY-F (Capital)	-	2,418	12,442	-	-	-	-	75	678	15,613
NY-GHI (Southeast)	7,429	318	12,971	-	-	-	-	-	768	21,486
NY-J (NY City)	-	5,694	24,100	-	-	-	-	-	400	30,194
NY-K (Long Island)	-	-	9,951	-	-	3	0	-	1,054	11,008
2019 Total All Zones	**39,672**	**32,760**	**62,610**	**398**	**-**	**1**	**-**	**8,419**	**6,043**	**149,903**
NY-AB (West)	4,474	14,866	1,579	13	-	-	-	1,850	1,449	24,231
NY-CDE (Cent North)	20,399	9,481	7,790	385	-	-	-	6,475	1,451	45,980
NY-F (Capital)	-	2,401	10,035	-	-	-	-	95	786	13,316
NY-GHI (Southeast)	14,799	318	11,383	-	-	-	-	-	814	27,314
NY-J (NY City)	-	5,694	22,054	-	-	-	-	-	446	28,195
NY-K (Long Island)	-	-	9,769	-	-	1	-	-	1,097	10,867
2020 Total All Zones	**38,523**	**32,726**	**64,504**	**334**	**-**	**1**	**-**	**9,907**	**6,519**	**152,514**
NY-AB (West)	4,126	14,855	1,536	-	-	-	-	2,248	1,553	24,317
NY-CDE (Cent North)	19,586	9,481	7,602	334	-	-	-	7,544	1,564	46,112
NY-F (Capital)	-	2,378	9,711	-	-	-	-	115	898	13,102
NY-GHI (Southeast)	14,810	318	13,695	-	-	-	-	-	862	29,686
NY-J (NY City)	-	5,694	22,258	-	-	-	-	-	494	28,446
NY-K (Long Island)	-	-	9,703	-	-	1	-	-	1,148	10,851
2021 Total All Zones	**39,351**	**32,730**	**67,952**	**327**	**-**	**1**	**0**	**11,740**	**7,033**	**159,134**
NY-AB (West)	4,151	14,854	1,512	-	-	-	-	2,875	1,663	25,054
NY-CDE (Cent North)	20,405	9,481	7,440	327	-	-	-	8,730	1,702	48,084
NY-F (Capital)	-	2,383	8,812	-	-	-	-	135	1,021	12,351
NY-GHI (Southeast)	14,795	318	15,699	-	-	-	-	-	908	31,721
NY-J (NY City)	-	5,694	22,959	-	-	-	-	-	543	29,196
NY-K (Long Island)	-	-	11,530	-	-	1	0	-	1,196	12,728
2022 Total All Zones	**38,770**	**32,749**	**67,471**	**307**	**-**	**1**	**-**	**13,415**	**7,500**	**160,214**
NY-AB (West)	4,475	14,853	1,463	-	-	-	-	3,488	1,766	26,045
NY-CDE (Cent North)	19,537	9,481	7,232	307	-	-	-	9,773	1,817	48,147
NY-F (Capital)	-	2,402	8,087	-	-	-	-	155	1,131	11,775
NY-GHI (Southeast)	14,757	318	14,998	-	-	-	-	-	955	31,029
NY-J (NY City)	-	5,694	24,242	-	-	-	-	-	589	30,526
NY-K (Long Island)	-	-	11,449	-	-	1	-	-	1,241	12,691
2023 Total All Zones	**39,299**	**32,785**	**66,745**	**311**	**-**	**1**	**0**	**15,050**	**8,029**	**162,221**
NY-AB (West)	4,114	14,859	1,453	-	-	-	-	3,864	1,870	26,161
NY-CDE (Cent North)	20,396	9,481	7,128	311	-	-	-	11,012	1,994	50,321
NY-F (Capital)	-	2,432	7,781	-	-	-	-	174	1,240	11,627
NY-GHI (Southeast)	14,789	318	15,024	-	-	-	-	-	1,002	31,133
NY-J (NY City)	-	5,694	23,945	-	-	-	-	-	636	30,275
NY-K (Long Island)	-	-	11,414	-	-	1	0	-	1,288	12,703
2024 Total All Zones	**38,556**	**32,810**	**66,519**	**317**	**-**	**-**	**-**	**17,165**	**8,014**	**163,381**
NY-AB (West)	4,162	14,858	1,451	-	-	-	-	4,275	1,859	26,605
NY-CDE (Cent North)	19,590	9,481	7,045	317	-	-	-	12,086	1,996	50,515
NY-F (Capital)	-	2,459	7,774	-	-	-	-	195	1,237	11,665
NY-GHI (Southeast)	14,803	318	14,150	-	-	-	-	-	1,001	30,273
NY-J (NY City)	-	5,694	22,823	-	-	-	-	-	635	29,151
NY-K (Long Island)	-	-	13,275	-	-	-	-	609	1,287	15,171
2025 Total All Zones	**39,617**	**32,804**	**67,658**	**307**	**-**	**-**	**-**	**18,339**	**8,124**	**166,850**
NY-AB (West)	4,473	14,856	1,433	-	-	-	-	4,658	1,851	27,270
NY-CDE (Cent North)	20,397	9,481	6,959	307	-	-	-	12,803	2,116	52,063
NY-F (Capital)	-	2,455	6,913	-	-	-	-	215	1,237	10,821
NY-GHI (Southeast)	14,747	318	12,862	-	-	-	-	-	999	28,927
NY-J (NY City)	-	5,694	24,094	-	-	-	-	55	634	30,478
NY-K (Long Island)	-	-	15,396	-	-	-	-	608	1,285	17,290

Scenario 41 - IPEC In-serv. Hi EE, Wind, PV + Offsh 8GW Tot Wind	Nuclear	Hydro&PS	NatGas	Coal	Oil 6	Oil 2	Ker	Wind	Other (Wood, Refuse, Bio, PV, DR/LaaR)	Total
2015 Total All Zones	**39,975**	**27,317**	**62,171**	**4,913**	**-**	**4**	**0**	**5,865**	**4,035**	**144,281**
NY-AB (West)	4,151	14,895	1,787	4,485	-	-	-	1,072	1,008	27,397
NY-CDE (Cent North)	20,408	9,481	8,924	428	-	-	-	4,737	1,001	44,978
NY-F (Capital)	-	2,624	16,488	-	-	-	-	55	348	19,515
NY-GHI (Southeast)	15,417	318	415	-	-	-	-	-	627	16,776
NY-J (NY City)	-	-	23,784	-	-	-	-	-	137	23,921
NY-K (Long Island)	-	-	10,774	-	-	4	0	-	914	11,693
2016 Total All Zones	**39,502**	**27,298**	**67,660**	**456**	**-**	**12**	**2**	**5,884**	**4,671**	**145,485**
NY-AB (West)	4,487	14,899	1,920	37	-	-	-	1,077	1,129	23,549
NY-CDE (Cent North)	19,587	9,481	9,092	419	-	-	-	4,752	1,121	44,452
NY-F (Capital)	-	2,600	16,659	-	-	-	-	55	460	19,775
NY-GHI (Southeast)	15,428	318	3,968	-	-	-	-	-	676	20,390
NY-J (NY City)	-	-	25,143	-	-	0	-	-	317	25,460
NY-K (Long Island)	-	-	10,877	-	-	12	2	-	969	11,860
2017 Total All Zones	**39,941**	**27,307**	**66,695**	**446**	**-**	**5**	**1**	**6,121**	**5,130**	**145,645**
NY-AB (West)	4,113	14,894	1,799	31	-	-	-	1,071	1,238	23,145
NY-CDE (Cent North)	20,407	9,481	8,715	415	-	-	-	4,994	1,230	45,242
NY-F (Capital)	-	2,615	15,091	-	-	-	-	55	569	18,329
NY-GHI (Southeast)	15,421	318	5,409	-	-	-	-	-	721	21,869
NY-J (NY City)	-	-	25,240	-	-	-	-	-	361	25,601
NY-K (Long Island)	-	-	10,440	-	-	5	1	-	1,012	11,458
2018 Total All Zones	**39,069**	**32,776**	**63,045**	**389**	**-**	**2**	**0**	**7,877**	**5,558**	**148,716**
NY-AB (West)	4,149	14,864	1,594	9	-	-	-	2,071	1,329	24,016
NY-CDE (Cent North)	19,531	9,481	7,800	380	-	-	-	5,731	1,332	44,254
NY-F (Capital)	-	2,419	10,299	-	-	-	-	75	677	13,470
NY-GHI (Southeast)	15,388	318	11,297	-	-	-	-	-	767	27,770
NY-J (NY City)	-	5,694	22,342	-	-	-	-	-	400	28,436
NY-K (Long Island)	-	-	9,714	-	-	2	0	-	1,054	10,771
2019 Total All Zones	**40,298**	**32,762**	**61,421**	**393**	**-**	**1**	**-**	**9,645**	**6,033**	**150,555**
NY-AB (West)	4,474	14,866	1,563	12	-	-	-	2,769	1,444	25,129
NY-CDE (Cent North)	20,399	9,481	7,739	381	-	-	-	6,781	1,447	46,227
NY-F (Capital)	-	2,403	9,684	-	-	-	-	95	785	12,968
NY-GHI (Southeast)	15,425	318	10,976	-	-	-	-	-	813	27,533
NY-J (NY City)	-	5,694	21,717	-	-	-	-	-	446	27,858
NY-K (Long Island)	-	-	9,741	-	-	1	-	-	1,097	10,840
2020 Total All Zones	**39,149**	**32,726**	**60,757**	**325**	**-**	**1**	**-**	**14,519**	**6,505**	**153,982**
NY-AB (West)	4,126	14,855	1,508	-	-	-	-	3,477	1,546	25,512
NY-CDE (Cent North)	19,586	9,481	7,503	325	-	-	-	8,159	1,559	46,613
NY-F (Capital)	-	2,378	8,972	-	-	-	-	115	897	12,363
NY-GHI (Southeast)	15,436	318	12,716	-	-	-	-	-	861	29,332
NY-J (NY City)	-	5,694	20,425	-	-	-	-	2,767	494	29,381
NY-K (Long Island)	-	-	9,633	-	-	1	-	-	1,148	10,782
2021 Total All Zones	**39,977**	**32,734**	**64,189**	**320**	**-**	**1**	**0**	**16,337**	**7,018**	**160,576**
NY-AB (West)	4,151	14,854	1,490	-	-	-	-	4,103	1,654	26,251
NY-CDE (Cent North)	20,405	9,481	7,310	320	-	-	-	9,345	1,697	48,557
NY-F (Capital)	-	2,387	8,262	-	-	-	-	135	1,020	11,805
NY-GHI (Southeast)	15,422	318	14,448	-	-	-	-	-	907	31,095
NY-J (NY City)	-	5,694	21,244	-	-	-	-	2,755	542	30,235
NY-K (Long Island)	-	-	11,436	-	-	1	0	-	1,196	12,633
2022 Total All Zones	**39,392**	**32,761**	**62,032**	**302**	**-**	**1**	**-**	**20,762**	**7,482**	**162,732**
NY-AB (West)	4,475	14,846	1,448	-	-	-	-	4,712	1,757	27,238
NY-CDE (Cent North)	19,537	9,481	7,129	302	-	-	-	10,385	1,810	48,645
NY-F (Capital)	-	2,422	7,448	-	-	-	-	155	1,131	11,156
NY-GHI (Southeast)	15,379	318	13,491	-	-	-	-	-	954	30,142
NY-J (NY City)	-	5,694	21,955	-	-	-	-	2,755	589	30,993
NY-K (Long Island)	-	-	10,561	-	-	1	-	2,755	1,241	14,558
2023 Total All Zones	**39,926**	**32,797**	**61,442**	**305**	**-**	**0**	**-**	**22,385**	**8,007**	**164,862**
NY-AB (West)	4,114	14,851	1,439	-	-	-	-	5,080	1,860	27,344
NY-CDE (Cent North)	20,396	9,481	7,040	305	-	-	-	11,622	1,984	50,827
NY-F (Capital)	-	2,453	7,269	-	-	-	-	174	1,240	11,136
NY-GHI (Southeast)	15,416	318	13,522	-	-	-	-	-	1,001	30,256
NY-J (NY City)	-	5,694	21,595	-	-	-	-	2,755	636	30,679
NY-K (Long Island)	-	-	10,578	-	-	0	-	2,755	1,287	14,619
2024 Total All Zones	**39,182**	**32,807**	**61,260**	**308**	**-**	**-**	**-**	**24,590**	**7,986**	**166,133**
NY-AB (West)	4,162	14,852	1,430	-	-	-	-	5,502	1,846	27,791
NY-CDE (Cent North)	19,590	9,481	6,948	308	-	-	-	12,699	1,984	51,010
NY-F (Capital)	-	2,462	7,102	-	-	-	-	195	1,236	10,995
NY-GHI (Southeast)	15,430	318	12,744	-	-	-	-	-	999	29,490
NY-J (NY City)	-	5,694	20,629	-	-	-	-	2,767	635	29,725
NY-K (Long Island)	-	-	12,407	-	-	-	-	3,428	1,287	17,122
2025 Total All Zones	**40,287**	**32,802**	**62,293**	**299**	**-**	**-**	**-**	**25,683**	**8,095**	**169,459**
NY-AB (West)	4,473	14,854	1,423	-	-	-	-	5,886	1,839	28,474
NY-CDE (Cent North)	20,397	9,481	6,881	299	-	-	-	13,414	2,103	52,575
NY-F (Capital)	-	2,455	6,563	-	-	-	-	215	1,237	10,469
NY-GHI (Southeast)	15,417	318	11,383	-	-	-	-	-	997	28,115
NY-J (NY City)	-	5,694	21,612	-	-	-	-	2,755	634	30,695
NY-K (Long Island)	-	-	14,433	-	-	-	-	3,413	1,285	19,131

Gold Book 2013 Loads and Peaks

Annual Energy (GWh)

	A	B	C	D	E	F	G	H	I	J	K
2012	15901	10031	16145	6561	7796	11456	10106	2917	6074	53662	23004
2013	15788	10071	16152	6701	8036	11712	10054	2922	6086	53762	22572
2014	15835	10073	16196	6789	8048	11716	10106	2938	6114	54016	22821
2015	15922	10076	16269	6835	8122	11803	10152	2951	6148	54310	22983
2016	15997	10083	16337	6850	8182	11872	10201	2976	6195	54732	23379
2017	16010	10080	16383	6866	8188	11926	10238	2976	6199	54762	23426
2018	16012	10080	16426	6874	8184	11978	10263	2993	6229	55032	23632
2019	16019	10080	16475	6868	8188	12028	10306	3007	6261	55309	23931
2020	16033	10085	16525	6871	8192	12077	10333	3029	6308	55727	24319
2021	16033	10081	16576	6889	8199	12126	10351	3038	6325	55878	24581
2022	16038	10081	16626	6895	8203	12173	10370	3053	6358	56172	24946
2023	16040	10082	16674	6888	8204	12220	10385	3071	6392	56471	25339
2024	16044	10082	16714	6892	8207	12259	10401	3084	6419	56706	25630
2025	16048	10083	16754	6896	8210	12298	10417	3097	6445	56943	25925
2026	16053	10083	16795	6900	8214	12337	10433	3110	6472	57180	26223
2027	16057	10084	16835	6904	8217	12376	10449	3123	6499	57418	26525
2028	16061	10084	16875	6908	8220	12415	10465	3136	6526	57657	26830
2029	16065	10084	16916	6912	8223	12454	10481	3150	6553	57898	27138
2030	16069	10085	16957	6916	8226	12494	10497	3163	6580	58139	27450

RNA 15x15 Loads and Peaks

	A	B	C	D	E	F	G	H	I	J	K
2012	15901	10031	16145	6561	7796	11456	10106	2917	6074	53662	23004
2013	15316	9867	15797	6632	8068	11682	9695	2835	5908	52176	21319
2014	15239	9785	15687	6701	8005	11550	9706	2795	5814	51358	21433
2015	15238	9700	15612	6660	8062	11559	9657	2760	5745	50758	21255
2016	15368	9706	15660	6653	8157	11638	9688	2772	5769	50962	21808
2017	15404	9704	15706	6632	8153	11723	9748	2773	5773	50995	21819
2018	15445	9729	15783	6633	8150	11814	9790	2779	5781	51081	22064
2019	15501	9765	15863	6597	8188	11891	9862	2778	5780	51068	22500
2020	15585	9812	15952	6582	8231	11969	9908	2785	5792	51180	23008
2021	15643	9833	16040	6614	8279	12034	9929	2778	5781	51082	23373
2022	15663	9828	16082	6598	8291	12051	9919	2793	5815	51379	23756
2023	15655	9823	16111	6553	8290	12086	9905	2800	5818	51422	24277
2024	15657	9815	16126	6526	8297	12099	9894	2796	5811	51348	24600
2025	15657	9811	16143	6502	8302	12113	9884	2792	5801	51273	24929

Peak Load (MW)

	A	B	C	D	E	F	G	H	I	J	K
2012	2822	2090	2925	936	1445	2375	2287	687	1437	11500	5526
2013	2657	2084	2904	868	1466	2368	2277	688	1433	11485	5515
2014	2688	2116	2941	887	1481	2395	2316	699	1454	11658	5566
2015	2716	2139	2969	897	1501	2431	2348	704	1475	11832	5609
2016	2734	2158	2996	903	1515	2458	2376	715	1496	12006	5688
2017	2743	2172	3012	906	1519	2480	2398	721	1511	12137	5713
2018	2749	2187	3032	910	1523	2502	2418	729	1527	12266	5760
2019	2755	2199	3045	910	1527	2520	2439	737	1542	12419	5827
2020	2763	2213	3064	911	1531	2540	2456	744	1559	12572	5902
2021	2769	2224	3079	915	1537	2558	2471	751	1574	12725	5979
2022	2776	2236	3099	917	1542	2577	2488	759	1587	12833	6060
2023	2783	2249	3113	916	1548	2598	2504	762	1594	12920	6149
2024	2789	2259	3127	917	1552	2614	2517	767	1605	13023	6216
2025	2789	2259	3134	918	1553	2622	2521	770	1611	13077	6287
2026	2790	2259	3142	918	1553	2630	2525	774	1618	13131	6359
2027	2791	2259	3149	919	1554	2639	2529	777	1625	13186	6432
2028	2792	2259	3157	919	1555	2647	2533	780	1631	13241	6506
2029	2792	2260	3165	920	1555	2656	2537	783	1638	13296	6581
2030	2793	2260	3172	920	1556	2664	2540	787	1645	13352	6657

	A	B	C	D	E	F	G	H	I	J	K
2012	2822	2090	2925	936	1445	2375	2287	687	1437	11500	5526
2013	2582	2025	2822	844	1425	2302	2213	669	1393	11163	5360
2014	2580	2031	2823	851	1421	2299	2223	671	1395	11189	5342
2015	2575	2028	2814	850	1423	2304	2226	667	1398	11216	5317
2016	2592	2046	2840	856	1436	2330	2252	678	1418	11381	5392
2017	2600	2059	2855	859	1440	2351	2273	683	1432	11505	5415
2018	2606	2073	2874	863	1444	2372	2292	691	1447	11627	5460
2019	2611	2084	2886	863	1447	2389	2312	699	1462	11772	5523
2020	2619	2098	2904	864	1451	2408	2328	705	1478	11917	5594
2021	2625	2108	2919	867	1457	2425	2342	712	1492	12062	5668
2022	2631	2119	2938	869	1462	2443	2358	719	1504	12164	5744
2023	2638	2132	2951	868	1467	2463	2374	722	1511	12247	5829
2024	2643	2141	2964	869	1471	2478	2386	727	1521	12344	5892
2025	2644	2141	2971	870	1472	2486	2390	730	1527	12395	5959

APPENDIX B: DETAILED DESCRIPTION OF MARKET ANALYTICS / PROSYM

Market Analytics is a zonal locational marginal-price-forecasting model that simulates the operation of the energy and operating reserves markets. The simulation engine used is PROSYM. The modeling system and the default data is provided by the model vendor, Ventyx.

The model does not simulate the forward capacity market and, therefore, does not require assumptions regarding the capital costs of new generation capacity and the interconnection costs associated with such capacity. However, the model does require assumptions about the quantity and type of existing and new capacity over the study horizon, fuel prices, and other factors. Section 2 catalogues the input assumptions to the model.

Unit Parameterization

PROSYM uses highly detailed information on generating units. Data on specific units in the Market Analytics database are based on data drawn from various sources including the U.S. Energy Information Administration, U.S. Environmental Protection Agency, North American Electric Reliability Corporation, Federal Energy Regulatory Commission (FERC), and New York ISO databases, as well as various trade press announcements and Ventyx's own professional assessment. Characteristics specified at the generating unit level include heat rate values and curve, seasonal capacity ratings, variable operating and maintenance costs, forced and planned outage rates, minimum up and down times, startup costs, ramp rates, and emissions rates.

Unit Commitment and Dispatch

Based upon hourly loads, PROSYM determines generating unit commitment and operation by transmission zone based upon economic bid-based dispatch, subject to system operating procedures and constraints. PROSYM operates using hourly load data and simulates unit dispatch in chronological order. In other words, 8,760 distinct hourly load levels are used for each TA for each study year. The model begins on January 1st and dispatches generating units to meet hourly loads. Using this chronological approach, PROSYM takes into account time-sensitive dynamics such as transmission constraints and operating characteristics of specific generating units. For example, one power plant might not be available at a given time due to its minimum down time (i.e., the period it must remain off line once it is taken off). Another unit might not be available to a given TA because of transmission constraints created by current operating conditions. These are dynamics that system operators wrestle with daily, and they often cause generating units to be dispatched out of merit order. Few other electric system models simulate dispatch in this kind of detail.

PROSYM simulates the effects of forced (i.e., random) outages probabilistically, using one of several Monte Carlo simulation modes. These simulation modes initiate forced outage events (full or partial) based on unit-specific outage probabilities and a Monte Carlo-type random number draw. Many other models simulate the effect of forced outages by "de-rating" the capacity of all generators within the system. That is, the capacities of all units are reduced at all times to simulate the outage of several units at any given time. While such de-rating usually results in a reasonable estimate of the amount of annual generation from baseload plants, the result for intermediate and peaking units can be inaccurate, especially over short periods.

PROSYM calculates emissions of NO_x, SO_2, and CO_2, and based on unit-specific emission rates and MWh output quantities.

The model's fundamental assumption of behavior in competitive energy markets is that generators will bid their marginal cost of producing electric energy into the energy market. The model calculates this marginal cost from the unit's opportunity cost of fuel or the spot price of gas at the location closest to the plant, variable operating and maintenance costs, and opportunity cost of tradable permits for air emissions.

Transmission

The smallest location in Market Analytics is a Location (typically representing a utility service territory) which for modeling purposes is mapped into a Transmission Area (TA). A TA may represent one or more Locations. Transmission areas represent sub regions of Control Areas such as PJM. Transmission areas are defined in practice by actual transmission constraints within a control area. That is, power flows from one area to another in a control area are governed by the operational characteristics of the actual transmission liens involved. PROSYM can also simulate operation in any number of control areas. Groups of contiguous control areas were modeled in order to capture all regional impacts of the dynamics under scrutiny. The interface limits used in the simulations reflect the existing system, ongoing transmission upgrades including those that comprise the planned TOTS projects as well as other expected additions detailed in section 2.2.

APPENDIX C: KEY DOCUMENTS/EXCERPTS

On the following pages, we have included key documents/excerpts from the following:

- NYPSC IPEC Contingency Plan Proceeding Case 12-E-0503 ConEd/NYPA Filings – February, May, June 2013
- NYPSC IPEC Contingency Plan Proceeding Order Case 12-E-0503 November 2013
- NYPSC AC Proceeding Filing NY Transco Intention to Build Case 12-T-0502 January 2013
- NYPSC AC Proceeding Orders Instituting Proceeding, and Rulings Case 12-T-0502 November 2012, April 2013, September 2013
- NYISO 2012 Reliability Needs Assessment – IPEC Outage Sensitivity - Excerpt
- NY ISO September 2013 Testimony NYS Senate Committee
- NYISO Growing Wind – Final Report of the NYISO 2010 Wind Generation Study – Excerpt

BEFORE THE STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission	**)**	
To Review Generation Retirement	**)**	**Case 12-E-0503**
Contingency Plan	**)**	

COMPLIANCE FILING OF
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
AND NEW YORK POWER AUTHORITY
WITH RESPECT TO DEVELOPMENT OF INDIAN POINT CONTINGENCY PLAN

Pursuant to the November 30, 2012 *Order Instituting Proceeding And Soliciting Indian Point Contingency Plan* ("November 30th Order"),[1] of the New York State Public Service Commission ("Commission"), Consolidated Edison Company of New York, Inc. ("Con Edison") and the New York Power Authority ("NYPA") hereby submit their Indian Point Contingency Plan (the "Plan").

I. EXECUTIVE SUMMARY

In its November 30th Order the Commission directed Con Edison with the assistance of NYPA to "develop a contingency plan for the potential closure of Indian Point upon the expiration of its existing licenses by the end of 2015."[2] As shown herein, the Plan is responsive to the requirements set forth in the November 30th Order and should be approved. To begin with, the Plan analyzed the impact that the retirement of the Indian Point Energy Center ("IPEC") [3] would have on the Bulk Power System ("BPS") taking into account the effect of the retirement

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[1] Case 12-E-0503, *Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans*.
[2] Order, p. 5.
[3] Con Edison and NYPA make no assumption or determination about the potential closure of IPEC. This Plan is intended to provide a reliability solution for New York State if IPEC closes.

of Dynegy Danskammer, L.L.C. Units 1 – 6 ("Danskammer") and the implementation of incremental energy efficiency ("EE") and demand response ("DR") programs. Accordingly, the Plan provides for a fast track approach to having EE and DR program resources and transmission and generation projects in service by June 2016 (the "In-Service Deadline") to meet the electricity needs that could arise from the closure of IPEC.[4]

Specifically, the Plan provides for a two pronged approach. The first prong has Con Edison and NYPA[5] moving forward this spring upon Commission approval to implement three Transmission Owner Transmission Solutions ("TOTS") so that they can be in place by the In-Service Deadline. The second prong has NYPA issuing a request for proposals ("RFP") in the spring to solicit new incremental generation and transmission proposals that could also be in place by In-Service Deadline. Department of Public Service ("DPS") staff will evaluate all of the proposed projects and will then recommend to the Commission which projects should move forward to completion. DPS staff may call upon the New York Independent System Operator ("NYISO"), Con Edison and NYPA for technical assistance in analyzing any data needed for DPS staff's evaluation. The recommended projects could include the TOTS and/or solutions resulting from the RFP. Upon Commission approval, the projects ultimately selected will move forward towards completion unless halted by a Commission order, subject to cost recovery and other criteria as described herein.

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[4] As described further, infra, the Plan provides for maintaining reliability criteria should IPEC close, resulting in enough resources to satisfy applicable reliability requirements in the summer of 2016, as such, the Plan is not intended to address levels of capacity with or without the retirement of IPEC. The Commission has also instituted a separate proceeding to solicit alternating current transmission upgrades. *See*, Case 12-T-0502, *Proceeding on Motion to Examine Alternating Current Transmission Upgrades*, Order Instituting Proceeding (November 30, 2013).

[5] This prong would also include New York State Electric and Gas Company ("NYSEG"), which is a co-sponsor of the MSSC Project, as defined infra.

The Plan consists of several integrated components, all of which need to be timely approved so that they can move forward according to the schedule specified herein. To make this Plan work, however, there are actions that the Commission needs to take to ensure that solutions are in place by the In-Service Deadline. If the Commission does not issue an order in April 2013, as requested below, authorizing Con Edison and NYPA to move forward with the TOTS subject to cost recovery and the halting mechanism, the likelihood of having sufficient resources available by the In-Service Deadline is greatly diminished. Moreover, completing all of these steps in the order proposed is a fundamental requirement without which each of the subsequent steps would be in jeopardy of being unable to proceed as proposed. Specifically, the Plan calls for the Commission to:

1. Issue an order[6] in March 2013 ("Interim Order") that:
    a. Requests that NYPA issue an RFP for new generation and transmission solutions and identifies any changes the Commission desires to the general description of the RFP terms, conditions, process and timeline described in this Plan;
2. Issue an order in April 2013 ("April Order") that:
    a. Directs Con Edison to implement its Indian Point EE/DR program as set forth in the Plan with cost recovery and subject to halting;
    b. Directs Con Edison to begin the development of the Second Ramapo to Rock Tavern 345 kV Line ("RRT Line") and the Staten Island Un-bottling ("SIU") Project, both of which will ultimately be transferred to and owned by the New

[6] Throughout this filing, the terms "order" and "directs" in this context means an order or direction of the Commission with respect to Con Edison and any other investor owned utility ("IOU") and a request with respect to NYPA.

York Transmission Company ("NY Transco"),[7] subject to the halting mechanism and cost recovery proposal set forth in this Plan;

c. Requests that NYPA, and directs that New York State Electric and Gas Corporation ("NYSEG"), begin the development of the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring ("MSSC") Project, which also will ultimately be transferred to and owned by the NY Transco,[8] subject to the halting mechanism and cost recovery proposal set forth in this Plan;

d. Approves this Plan, including full recovery of all prudently incurred costs using the cost recovery and cost allocation approach set forth in Section VI of the Plan and the halting mechanism proposal described more fully in the Plan; and

e. Finds, on a preliminary basis, that the RRT Line; the MSSC Project; and the SIU Project are public policy projects that meet the public policy requirements of New York State, as identified in the November 30th Order and the New York Energy Highway Blueprint ("Blueprint")[9];

[7] As discussed more fully later in this filing, Con Edison and NYPA are active participants in the process of creating the NY Transco, a state-wide transmission company which will seek to develop transmission in New York State, including the RRT Line, the MSSC Project and the SIU Project that are being submitted as solutions in this docket. Two of these projects, the RRT Line and the MSSC Project, along with three other transmission projects, were also submitted as NY Transco projects in Commission Case 12-T-0502. As explained herein, Con Edison and NYPA intend that after these projects are started, they will be transferred to and owned by the NY Transco.

[8] *See* footnote 6, supra.

[9] A copy of the Blueprint can be found at: http://www.nyenergyhighway.com/PDFs/Blueprint/EHBPPT/.

3. Establish a public comment period in this docket pursuant to the State Administrative Procedure Act ("SAPA") to solicit comments on the proposed public policy requirement of developing an Indian Point Contingency Plan;
4. Issue an order in September 2013 ("September Order") that:
    a. Selects a final set of transmission and/or generation projects to move forward subject to the halting, cost allocation, and cost recovery mechanisms set forth in this Plan;
    b. Finds, pursuant to the SAPA public comment process, that developing and implementing an Indian Point Contingency Plan is a state public policy requirement that drives the need for transmission;
    c. Finds, to the extent that any of the TOTS are selected as final projects, that the RRT Line, the MSSC Project, and the SIU Project are public policy projects that meet the specified public policy requirements of New York State, as identified in the November 30th Order and the Blueprint;
    d. If any of the TOTS are chosen by the Commission as a Selected Project, as defined, infra, (i) authorizes Con Edison and NYSEG to fully recover, and (ii) establishes a mechanism to enable NYPA to fully recover, all reasonable and prudent costs incurred in pursuing each TOTS, to the extent such costs cannot otherwise be recovered through the NYISO tariff pursuant to the cost allocation method described in this Plan;

e. Directs that each New York Transmission Owner ("NYTO")[10] impacted by the Plan modify its retail cost recovery mechanisms for transmission and transmission-related costs, to the extent necessary, to provide that all NYISO transmission charges allocated to that individual NYTO as a result of the September Order will be recovered from that NYTO's retail customers;

f. Authorizes the recovery by Con Edison of all costs incurred in developing and implementing this Plan; and

g. Establishes a mechanism to enable NYPA to recover all costs incurred in developing and implementing this Plan, as more fully explained in Section VI of the Plan.

Accordingly, for the reasons set forth in this compliance filing, Con Edison and NYPA respectfully request that the Commission approve the Plan and issue orders, as specified above, such that the Plan can be implemented.

II. BACKGROUND

IPEC, which is owned by Entergy and located in Buchanan New York, consists of two nuclear generating facilities (Units 2 and 3), each capable of producing approximately 1020 MW for a total output of 2040 MW. Each of Unit 2 and 3 operate under a license from the Nuclear Regulatory Commission ("NRC"). Unit 2's NRC license expires in September 2013 and Unit 3's NRC license expires in December 2015. Entergy has submitted a timely request to the NRC to extend its license, which is currently pending before the NRC.

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[10] The NYTOs consist of Central Hudson Gas and Electric Corporation, Con Edison / Orange & Rockland Utilities, Inc., Niagara Mohawk Power Corporation / National Grid, and New York State Electric & Gas Corporation / Rochester Gas and Electric Corporation, NYPA and the Long Island Power Authority.

The November 30th Order noted that the loss of IPEC "could result in significantly reduced reliability at the time of retirement and for several years thereafter until replaced."[11] According to the Commission, the "value of a Reliability Contingency Plan to address reliability concerns associated with the closure of the nuclear power plants at the Indian Point Energy Center is increasingly apparent."[12]

The November 30th Order required that the Plan address reliability needs that could result for the summer of 2016 so that the state would be ready for the closure of such a large generation facility, whether or not the facility is actually closed at that time. In other words, the directive in the November 30th Order indicates that the Commission has deemed it necessary and appropriate to pursue a public policy contingency plan for the possible closure of IPEC. Moreover, the November 30th Order stated that the Plan should account for the status of existing or proposed transmission facilities, EE, DR and other energy resources and include a competitive process to procure new resources.[13] In addition, the November 30th Order required that the Plan include a halting mechanism to control ratepayer costs in the event that a project that is being developed to address the potential closure of IPEC needs to be stopped.[14] The halting mechanism recognizes that to meet the In-Service Deadline, some projects will need to start design and engineering in early 2013.

The Commission established February 1, 2013 as the due date for the Plan.

III. APPLICABLE CRITERIA AND ANALYSIS

The NYISO undertakes an assessment of the reliability needs of the state's BPS every two years. The latest approved NYISO comprehensive planning study that encompasses the year

[11] Order, p. 4.
[12] Order, pp. 1-2.
[13] Order, pp. 5-7.
[14] Order, p. 7.

2016 is the 2012 Reliability Needs Assessment ("RNA").[15] The model and the assumptions used to develop the 2012 RNA were the result of extensive stakeholder review and represent the NYISO's most recent evaluation of supply and demand resources over the next ten years. Con Edison used the 2012 RNA analysis as the starting point in its analysis, noting that the NYISO base case analysis keeps IPEC in service (based on the NYISO rules and process employed for assessment of generator retirements), although the 2012 RNA did include a sensitivity analysis that considered the potential retirement of IPEC. The New York State Reliability Council ("NYSRC") Reliability Rules[16] state the reliability criteria that must be followed in planning the statewide BPS as well as the New York City ("NYC") system. The applicable NYSRC rule for planning the system in New York is Rule B-R1 and it applies after any first contingency ("Statewide Analysis"). This rule requires that the BPS must have sufficient resources to:

1. Return all facilities back within normal ratings after any first contingency, and,
2. Ensure the system will not exceed Long Term Emergency ("LTE") ratings if any second contingency were to occur.

The NYISO further expands the coverage of the statewide applicability of B-R1 to non-BPS facilities it considers important for the reliability of the New York Control Area ("NYCA") system. The augmented list defines the Bulk Power Transmission Facilities ("BPTF") system, which are examined in step 2 for statewide analysis. Rule I-R1 further states that certain portions of the Con Edison system in New York City ("NYC") must be designed to a "second

[15] A copy of the 2012 RNA can be found at: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/2012_RNA_Final_Report_9-18-12_PDF.pdf.

[16] A copy of the NYSRC reliability rules can be found at: http://www.nysrc.org/pdf/Reliability%20Rules%20Manuals/RR%20Manual%20Version%2031%205-11-2012%20Final.pdf.

contingency" ("NYC Analysis"). The Con Edison Planning Criteria[17] comply with I-R1 by modifying item 2 as follows:

2. Return all facilities back to normal ratings after any second contingency in the Con Edison system.

These different NYC and statewide deficiency standards may yield different results. The larger of the two deficiencies, if any, becomes the stated deficiency, with the understanding that the solution set must address both deficiencies, because they may occur in different parts of the system and the entire state needs to meet the NYSRC rules. The interaction between the solutions and the studied contingencies are different in the Statewide Analysis than in the NYC Analysis, because the contingencies studied are different, as explained above. For example, in step 1, the most severe statewide contingency may not be the same as the most severe NYC contingency.

As mentioned above, the deficiency analysis started with the NYISO's 2012 RNA model and then updated it to reflect the rescission of the mothball notice for Astoria Generating Company, L.P.'s Gowanus barges 1 and 4 and the effect of the EE/DR projects that the Order required Con Edison and NYPA to consider. The model reflects 100 MW of incremental EE/DR, as further detailed below. Based on this updated analysis ("Updated 2012 RNA"), the retirement of IPEC would yield a deficiency of 950 MW.[18] This was determined from the NYC Analysis. The Statewide Analysis resulted in a lower deficiency level. It must be noted that solutions may have a different impact on the magnitude of the reduction in deficiency for the NYC Analysis than they do for the Statewide Analysis.

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[17] Con Edison's planning criteria is posted on its website at: http://www.coned.com/documents/Transmission_Planning%20_Criteria.pdf.

[18] The 950 MW deficiency is net of Con Edison's 100 MW EE/DR program.

The retirement of Danskammer was announced in January 2013 when the analysis presented above was nearing completion. Preliminary calculations made close to the filing date show an impact in the order of 400-425 MW for both the NYC Analysis and the Statewide Analysis from the closure of Danskammer. Accordingly, the overall deficiency, would be approximately 1350 to 1375 MWs.[19]

IV. <u>ENERGY EFFICIENCY AND DEMAND RESPONSE</u>

The November 30th Order directed that energy efficiency ("EE"), demand response ("DR"), and combined heat and power ("CHP") be taken into consideration in developing the amount of the deficiency that could result from the retirement of IPEC. Achieving demand reduction through new incremental programs will help reduce the need for additional generating or transmission capacity, which ultimately creates a long term avoided cost benefit for customers. Con Edison proposes to achieve an additional peak demand reduction of 100 MW by the In-Service Deadline through incremental programs ("IPEC EE/DR Program"). As such, the calculated deficiency due to the potential retirement of IPEC reflects this incremental 100 MW reduction. The details of the IPEC EE/DR Program are specified in Exhibit A.

As more fully described in Exhibit A, this 100 MW of incremental peak demand reduction can be implemented prior to the In-Service Deadline provided that: (1) approval to proceed and begin the incremental EE/DR surcharge collections is granted in the April Order; and (2) Con Edison is granted more flexibility to implement incremental programs than what is currently offered through the existing Energy Efficiency Portfolio Standard ("EEPS") programs.

The IPEC EE/DR Program will be additional to the suite of existing EEPS programs, with a focus on creating a holistic portfolio of solutions for reducing and managing loads

[19] The 1,350 to 1,375 MW deficiency is also net of Con Edison's 100 MW IPEC EE/DR Program.

primarily in large buildings. The IPEC EE/DR Program portfolio will include EE measures such as: LED lighting, installed advanced high efficiency HVAC and energy storage systems, and an extension of the steam air conditioning ("AC") incentives to all existing steam AC customers in addition to the Con Edison targeted Steam AC program initiated in October 2012. The range of programs envisioned under this portfolio approach would require the Commission to authorize in its April Order funding of at least $300 million to facilitate IPEC EE/DR Program success.[20]

In the event that the Commission terminates this Program prior to its approved conclusion through a halting order, Con Edison would continue collection of funds necessary for fulfillment of all customer commitments in place at the time of program halting and terminate the program from that point forward. Con Edison does not believe that reinstating programs after termination would be a viable option because of the time needed to ramp programs up and the attendant uncertainty that termination and subsequent reinstatement introduces into the market. With respect to the IPEC EE/DR Program, the estimated costs of halting at the key points in time are shown in Table 4.1 below:

TABLE 4.1

IPEC EE/DR Program	Date Halted	Estimated Partial At Risk Cost*
(Project Total: $300,000,000)	9/30/2013	$500,000
	3/31/2014	$13,000,000
	12/31/2014	$70,000,000
* The "Estimated Partial At Risk Cost" is an estimate of the funds necessary for fulfillment of customer commitments in place at the time based on an estimate of a 2016 in-service date.		

[20] There may be joint opportunities with NYSERDA to achieve these incremental energy efficiency increases that contribute to peak load reductions. The Commission may choose to evaluate NYSERDA funding levels in order to achieve the incremental goal.

Con Edison has also initiated discussions with its partners at NYPA and NYSERDA to identify incremental EE, DR, and CHP initiatives over and above what is already included in the 2012 RNA that can be achieved prior to the In-Service Deadline. There exists a combination of programs with funding that is not currently included in the Updated 2012 RNA which is still being reconciled[21]. The Plan will ultimately incorporate these during the evaluation process that determines the final set of transmission and generation solutions. See Exhibit G for additional details.

V. PROPOSED SOLUTION

A. Overview

As stated in the Order:

> The potential retirement of a significant electric generating facility, such as the Indian Point Energy Center, requires significant advanced planning. Specifically, the size, location, and uncertainties regarding the potential retirement of the Indian Point Energy Center warrant such planning activities at this time. [The Commission] agree[s] there is a need to develop a contingency plan now to ensure reliability in the event the Indian Point Energy Center is ultimately retired.[22] (footnote omitted).

To have transmission and/or generation solutions in place by the In-Service Deadline, it is essential that action be taken without delay so that projects can get underway quickly. To that end, the Plan contemplates pursuing a two-pronged approach in parallel. On the first prong of the solution, Con Edison and NYPA, working with and as part of the NY Transco,[23] would begin developing the three TOTS. On the second prong, NYPA would begin a competitive

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[21] The impact could be as much as 88 MW once the programs in-progress are fully identified and accounted for. These programs are in addition to the 100 MW incremental demand reduction to be achieved through the IPEC EE/DR Program.

[22] Order, pp. 1-2.

[23] *See* footnote 6, supra.

procurement process by issuing an RFP to solicit third party generation and third party transmission solutions to the potential closure of IPEC.

The Plan provides that the Commission will issue the Interim Order in March 2013 that requests NYPA to move forward with the RFP and provides input on any changes to the RFP terms, conditions and procedures desired by the Commission. The Plan also provides that the Commission will issue an order in April 2013 approving the Plan and authorizing Con Edison and NYPA to move forward with the EE/DR plan and with preliminary implementation of the TOTS, all subject to cost recovery and the halting mechanism. If the Commission does not issue an order in April 2013 authorizing Con Edison and NYPA to move forward with the TOTS subject to cost recovery and the halting mechanism, the likelihood of having sufficient resources available by the In-Service Deadline to address the potential closure of IPEC is greatly diminished.

Promptly upon receipt of the Interim Order, NYPA will issue an RFP soliciting generation and transmission solutions from private developers. The timeline and procedures by which the RFP process will be conducted are described below. Due to the number of steps involved and the statutory and regulatory requirements that must be satisfied, it is likely that a final selection of solutions will not occur, and third party project implementation will not be able to commence, before September or October 2013.

The Plan contemplates that DPS staff will evaluate the projects that respond to the RFP and the TOTS on a comparable basis and that the Commission will issue an order in September 2013 indicating the projects that will ultimately move forward to meet this public policy objective of preparing the state for the closure of IPEC. DPS staff may call upon the NYISO, Con Edison and NYPA for technical assistance in analyzing any data needed for DPS staff's evaluation.

Each of the TOTS will be subject to the halting mechanism described below that will enable the Commission to terminate or suspend development efforts. Once the TOTS begin, the projects will continue unless the Commission issues an order directing that a specific TOTS project be halted.

B. Transmission Owner Transmission Solutions (TOTS)

1. Description of the TOTS

To ensure that the TOTS are in place by the In-Service Deadline, the Plan calls for the Commission to issue an Order in April 2013 directing that the following three transmission projects[24] move forward, subject to the halting and cost recovery mechanisms discussed later in this filing:

- RRT Line;
- MSSC Project; and
- SIU Project.

For a detailed description of each of these projects, please see Exhibit B for the RRT Line, Exhibit C for the MSSC Project, and Exhibit D for the SIU Project. As indicated in these exhibits, the estimated cost at the time of completion for each of these projects is: $123.1 million for the RRT Line; $76 million for the MSSC Project; and $311.64 million for the SIU Project.

[24] The NY Transco's East Garden City to New Bridge Road Project is still being evaluated to determine if it is able to expedite its schedule to meet the In-Service Deadline. If it can, it could be considered an additional TOTS project in this process, and an update will be provided to the Commission.

As more fully described in these exhibits, each of these TOTS can be completed by the In Service Deadline, provided that they timely receive the various governmental and regulatory approvals set forth in Exhibits B, C, and D. Specifically, the RRT Line, which already has its Article VII Certificate, can be in service by the In-Service Deadline, provided that it receives approval of its amended Environmental Management and Construction Plan ("EM&CP") by the first quarter of 2014. The MSSC Project can be in service by the In-Service Deadline, provided that all major licensing and permitting is completed by the end of 2013. Finally, the SIU Project can be completed by the In-Service Deadline, provided work on the project commences during the spring of 2013. The chart below shows the licenses, regulatory and study approvals already received by the proposed projects.

Second Rock Tavern to Ramapo 345kV Line	• NYISO approved System Impact Study ("SIS") August 16, 2012, Queue position 368 • Article VII Certificate Received January 25, 1972, Case 25845, Con Edison and Case 25741, Con Edison and O&R • Article VII Certificate Received January 24, 2011, Case 10-T-0283, O&R, Inc. (Feeder 28)
Marcy Series Compensation and Fraser to Coopers Corners Reconductoring Project	• NYISO Interconnection Application filed May 12, 2012; Queue position 380
Staten Island Un-bottling	• NYISO granted Con Edison a waiver of its SIS and Queue requirements on January 18, 2013

2. <u>Ownership of the TOTS</u>

As indicated in the NYTOs' January 25, 2013 submission (the "January 25th Filing") in Case 12-T-0502, *Proceeding on Motion to Examine Alternating Current Transmission Upgrades,* Con Edison and NYPA are active participants in the process of creating the NY

Transco,[25] which will seek to develop transmission facilities in New York State including the RRT Line, the MSSC Project, and the SIU Project that are being submitted as solutions in this proceeding.[26] It is anticipated that the NY Transco will be formed in October 2013. Also as indicated in the January 25th Filing, the NYTOs are in the process of developing the regulatory filings necessary to establish a transmission rate schedule at the Federal Energy Regulatory Commission ("FERC") as well as to implement the cost allocation and cost recovery mechanisms through the NYISO's tariff as described herein. Final regulatory approvals from FERC are anticipated in April 2014. Once FERC approval is obtained, the NY Transco will lead the development of the TOTS. To that end, Con Edison and NYPA will begin the work on these TOTS until the NY Transco is operational.[27] At that time the TOTS will be transferred to and completed by the NY Transco.

Moreover, as further indicated in the January 25th Filing, the NY Transco Projects are being proposed to accomplish the goals and objectives of the Commission's November 30, 2013 order in Case 12-T-0502,[28] which are to increase transfer capability through the central east interface[29] and to "meet the objectives of the Energy Highway Blueprint."[30] As is the case with the full panoply of NY Transco projects, the RRT Line and MSSC Project will provide

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[25] The NY Transco will be a New York limited liability company ("LLC") that will be owned by affiliates of the NYTOs.

[26] In total, the NYTOs on behalf of the NY Transco proposed five projects in Case 12-T-0502. These projects are: MSSC Project; RRT Line; UPNY/SENY Interface Upgrade; Second Oakdale to Fraser 345 kV Line; and Marcy to New Scotland 345 kV Line. Con Edison and NYPA respectfully request that the Commission approve the NYTOs' January 25th Filing.

[27] It should be noted that the MSSC Project is being co-developed with NYSEG until the NY Transco takes over the development of that project. It is anticipated that following the issuance of the April Order, NYSEG would participate in the development of the MSSC Project.

[28] Case 12-T-0502, *Proceeding on Motion to Examine Alternating Current Transmission Upgrades*, Order Instituting Proceeding (November 30, 2013), p. 2.

[29] Id.

[30] Id.

congestion reduction benefits across key transmission interfaces and provide the public policy benefits specified in the Blueprint. As set forth in the January 25th Filing, the RRT Line and the MSSC Project, together with the other NY Transco projects, will provide significant public policy benefits to New York State, including production cost savings, job growth, increased local tax revenues, and emissions reductions. Due to their nature and location, these two projects are also highly effective solutions to the deficiency that would result from the closure of IPEC, and they can meet the In-Service Deadline requirement.

The SIU Project is also a NY Transco project, although it was not submitted as part of the January 25th Filing, since it does not directly affect congestion over the Central East Interface. The Plan calls for Con Edison to begin the work on the SIU Project, because it helps to address the reliability need associated with closure of IPEC. When the NY Transco is operational, this project will also be transferred to and finished by the NY Transco. As is the case with RRT Line and MSSC Project, this project provides the public policy benefits specified in the Blueprint.

C. Details of the Competitive Solicitation Process

The second prong in the Plan is the competitive solicitation process. This section includes procedures that will be followed to solicit proposals for generation and transmission resources that can be put in place on or before the In-Service Deadline to address the reliability needs that will result if IPEC ceases operations at the termination of its NRC licenses. It also sets forth criteria that will be employed to evaluate on a comparable basis all of the available solutions to the reliability need.

1. Steps and Timeline

Following issuance of the Interim Order, NYPA will issue the generation and transmission RFP, which is expected to occur around mid-March, 2013. Proposals in response to the RFP ("Proposals") will be due from respondents ("Respondents") approximately 45 to 60 days after its issuance (May or early June, 2013). Shortly after issuance of the RFP, NYPA will schedule a bidders' conference to address any questions Respondents may have so that they may be guided in the development of their Proposals. Upon receipt of the Proposals, DPS staff will evaluate and analyze the complete set of Proposals, together with the TOTS, to determine which group of solutions can be expected to best satisfy the reliability needs, consistent with the evaluation criteria described below. DPS staff may call upon NYISO, Con Edison and NYPA for technical assistance in analyzing any data needed for DPS staff's evaluation

Upon conclusion of the evaluation process, DPS staff will prepare a recommendation for Commission review and action in the September Order. The recommendation will state which solutions should be pursued and may include a combination of one or more Proposals and TOTS. It is expected that the DPS staff recommendation will be presented to the Commission for action as soon as August 2013. Thereafter, on or about September 14, 2013, the Commission is expected to issue its September Order to designate the combination of Proposals and/or TOTS that it authorizes to move forward ("Selected Projects").

If the Selected Projects include one or more generation projects (each a "Selected Generation Project"), NYPA and the developer of each Selected Generation Project will negotiate and enter into a power purchase agreement ("PPA") as expeditiously as possible to support development, construction and operation of such Selected Generation Project.[31] If the Selected Projects include a transmission resource (whether a TOTS or an alternative transmission facility, each a "Selected Transmission Project"), the developer of the Selected Transmission Project will seek approval to construct, operate and receive compensation for its Project pursuant

[31] Con Edison will not be a counter party to any generation contract.

to a NYISO and/or Commission tariff. It is anticipated that the September Order will authorize the creation of a Commission tariff for the recovery of Selected Project costs that will be available to the extent an appropriate NYISO tariff is not available at the time the September Order is issued. As is the case for TOTS, the other Selected Projects chosen as part of the competitive solicitation process may also be halted under certain conditions.

2. RFP Terms and Conditions

Respondents will be required to provide written submissions setting forth in as much detail as possible the information identified in the RFP. A sample of the type of information that will be solicited in the RFP is set forth on Exhibit E. This sample, representative information list is provided for indicative purposes, but the list of required information included in the RFP may differ. Likewise, Con Ed and NYPA will be required to provide, at the same time as the Respondents, the same information as is required of the Respondents, so that the TOTS and Proposals can be evaluated by DPS staff on a comparative basis.

The RFP will include a form of PPA for generators that will set forth in detail provisions related to, among other things, the posting by the project proponent of security deposits to secure completion of the work, completion of milestones, and the halting mechanism, consistent with the description below. Likewise, the RFP will set forth similar requirements for transmission Proposals.[32] Respondents must identify at the time of Proposal submission any requested changes or additions to the process, the project agreements and/or requirements. An indicative list of the type of contractual terms and conditions, including milestones, is included as Exhibit

[32] We note, as well, that as part of the NYISO interconnection process, the developer of a Proposed Transmission Project may be obligated to enter into the NYISO's FERC-approved pro forma Large Facility Interconnection Agreement pursuant to the Large Facility Interconnection Procedures set forth in Attachment X of the NYISO Services Tariff.

F. Respondents should also indicate whether any of the information contained in their response should be considered as confidential.

The RFP will also require Respondents proposing generation solutions to submit pricing in two forms. The first will be in the form of a contract for differences ("CFD") in which the total cost of the project is fixed, but the monthly payment due will be reduced by the amount of the market revenues available to the project for that month. The second required bid form will state the fixed amount that the project developer requires on a dollar per month basis for support in addition to the market revenues it expects to realize. This second bid form is similar to the approach employed in the Renewable Portfolio Standards venue.   Although there are benefits to either structure, requiring the submittal of this information will allow the evaluation process to consider the relative benefits of a known fixed monthly payment stream versus the variable customer costs associated with the CFD.

3. <u>Comparative Evaluation Process</u>

Both the TOTS and Proposals will be evaluated on a number of levels throughout the evaluation process. Initially, the Proposals will be subject to threshold criteria before being considered in the evaluation of their ability to meet the need and other criteria. This screening will consider whether the Proposal meets the following threshold criteria:

- Proposal received on time and in the proper format;
- Proposal is able to meet the In-Service Deadline;
- Generation proposals must provide at least 75 MW (UCAP) of incremental capacity;
- Both generation and transmission proposals must be interconnected to NYISO Load Zones G-K; and,

- Proposal provides pricing that is firm through December 31, 2013.

Proposals that meet the threshold criteria will then be subject to the evaluation process. This evaluation process will first review the Proposals for completeness and adherence to the RFP information request.[33] A detailed review of both the TOTS and Proposals' development plans will then be undertaken. Proposed solutions that have a high likelihood of technical and financial feasibility, as well as the ability to meet the In-Service Deadline, will then be subject to the next stage of the evaluation process.

Given that a single project is unlikely to meet the entire deficiency need, proposed solutions may be grouped into portfolios of projects and evaluated based on the categories listed below:

- Ability to help ensure that the reliability of the electric system is maintained or enhanced in the event of IPEC's closure, considering individual and collective impacts on the portfolio of Proposals;
- Deliverability;
- Cost-effectiveness and long-term public policy benefits to the State; including metrics such as production cost analysis
- Environmental considerations including emissions impact and use of existing rights-of-way; and
- Ability to provide opportunities for economic development and job creation.

The portfolio of projects that offers the best overall value to New York ratepayers based on the comprehensive evaluation process will be recommended by DPS staff for implementation.

[33] DPS staff will have the right to: (1) reject a response if it not complete; (2) contact bidders to clarify incomplete and/or unclear information in proposals; and (3) interview each bidder to obtain information regarding its project.

To perform this evaluation, Respondents will be asked to provide all pertinent information, a sample of which is described in Exhibit E.

VI. COST RECOVERY AND COST ALLOCATION MECHANISM

A. NYPA Cost Allocation and Cost Recovery Mechanism

To the extent any costs related to developing and implementing this Plan[34] are to be allocated to NYPA on behalf of its customers, the Commission should recognize that NYPA can accept costs only to the extent that NYPA's contracts with its customers allow recovery of such costs. The recovery of any costs that NYPA is contractually unable to recover from its customers ("Shortfall Amount") should first be recovered from the same end users to the extent that those same customers receive delivery service from the other NYTOs, excluding NYPA. To the extent that a Shortfall Amount still exists, that Shortfall Amount would have to be reallocated to the other end-users, including from NYPA customers whose contracts allow it.

In addition to recovering the Shortfall Amount, the Commission should require that once Commission-jurisdictional utilities and load serving entities ("LSEs") recover costs related to the development and implementation of this Plan that are incurred by NYPA and that are not recoverable through the NYISO tariff, those LSEs and utilities must remit any such costs recovered from their retail rate customers to NYPA. The mechanism developed by the Commission to address the particular cost recovery issues that pertain to NYPA described above is hereinafter referred to as the NYPA Recovery Mechanism.

[34] These costs included, but are not limited to, those incurred in preparing this Plan, developing the form of RFP, issuing the RFP, assisting (if requested) DPS staff, pursuing the TOTS, and all costs incurred in connection with the Selected Projects.

B. Cost Recovery and Cost Allocation Associated With Plan and RFP Related Expenses Incurred Before the September Order

Following the issuance of the Order, Con Edison and NYPA have incurred, and will continue to incur, costs in preparing the Plan, developing the form of RFP and associated agreements, issuing the RFP, contracting for consultants and outside legal representation, and assisting in the technical evaluation of Proposals (if requested), among other costs ("Plan & RFP Costs"). The April Order must ensure that: (1) Con Edison is able to recover all of its Plan & RFP Costs; and (2) NYPA is able to recover all such Plan & RFP Costs consistent with the NYPA Recovery Mechanism discussed in point VI.A. The Commission will determine the cost allocation approach for the Plan & RFP Costs. It is expected that in the April Order the Commission will allocate such costs on an appropriate public policy basis.

C. Cost Recovery and Cost Allocation Associated With TOTS Prior to the September Order

Following issuance of the April Order, Con Ed, NYPA and NYSEG will incur significant expenses associated with pursuing each TOTS until such time as it either is halted by a Commission order or is chosen as a Selected Project ("TOTS Costs"). The April Order must ensure that Con Edison, NYPA and NYSEG are able to recover all such TOTS Costs.

As stated in their January 25th Filing, the NYTOs, on behalf of the NY Transco, will pursue the establishment of a wholesale transmission revenue requirement and FERC-approved rate for the NY Transco projects, including the three TOTS projects proposed herein, that would be stated in the NYISO's Open Access Transmission Tariff ("OATT").[35] Once approved by FERC, the NY Transco's revenue requirement will be recovered from ***all*** LSEs in the NYISO's control area as specified in the January 25th Filing. The NYISO will be responsible for billing

[35] See January 25th Filing, pp. 21-24.

and collecting from all LSEs based on their energy consumption and location. The NY Transco will receive payments from the NYISO after the NYISO receives payments from the LSEs. The NYTOs, in their role as an LSE, will pass the NY Transco charge onto their full service retail customers as a NYISO charge consistent with their PSC-approved retail tariffs or, where necessary, under newly approved PSC tariffs. Accordingly, Con Edison and NYPA propose that the cost allocation method proposed in the January 25th Filing in Commission Case 12-T-0502 also apply to the TOTS for the same reasons set forth in that filing.

Until the NY Transco is operational, Con Edison and NYPA need certainty of cost recovery to proceed with their TOTS. In addition, since NYSEG is one of the NYTO developers of the MSSC Project, NYSEG also needs certainty of cost recovery to proceed with its part of the TOTS. Accordingly, Con Edison and NYPA request that the April Order state that the Commission is authorizing the recovery through a Commission jurisdictional method by Con Edison and NYSEG of all reasonable and prudent costs incurred in pursuing each TOTS, to the extent such TOTS Costs are not otherwise recovered through the NYISO tariff. In the case of NYPA, to the extent that such costs are not recovered through the NYISO tariff, such costs will be recovered through the NYPA Recovery Mechanism.[36] Further, to effectuate the cost allocation and cost recovery of the TOTS, the Commission should order each NYTO impacted by one of these projects to modify its retail cost recovery mechanisms for transmission and transmission related costs, to the extent needed, to provide that all NYISO transmission charges allocated to an individual NYTO in response to this Order will be recovered from that NYTO's retail customers. Finally, to the extent that the TOTS Costs cannot be recovered through the

[36] To the extent that Con Edison or NYPA are able to recover the costs of the TOTS through a FERC-approved rate, Con Edison and NYPA will refund to customers any costs already collected through Commission approved rates.

NYISO tariff, the Commission should establish a mechanism to allocate such costs consistent with public policy objectives, to all appropriate entities, including non Commission-jurisdictional entities, such as LIPA.

D. Cost Recovery and Cost Allocation Associated With Selected Projects

The final group of Selected Projects chosen by the Commission in the September Order may include a mix of TOTS, Selected Transmission Projects and Selected Generation Projects. The recovery of TOTS was discussed above.

If the competitive solicitation process results in a Selected Generation Project, the developer will be paid by NYPA pursuant to its PPA. These costs cannot be recovered through the NYISO tariff. Thus, the Commission also must ensure that the NYPA Recovery Mechanism enables NYPA to recover all costs in connection each Selected Generation Project consistent with the discussion in point A, above. The Commission could accommodate this by requiring LSEs and utilities that are allocated costs pursuant to the implementation of this plan to modify their retail rate mechanisms, to the extent necessary, to recover such costs from their retail customers. In addition, the Commission should require that those LSEs and utilities to remit any such costs recovered from their retail rate customers to NYPA.

The Commission will determine the cost allocation approach for each Selected Generation Project, with consideration of the public policy value across the State, including Long Island.[37] It is expected that in the September Order the Commission will allocate such costs on an appropriate public policy basis. It is possible that different allocations will apply to different Selected Projects. To the extent that the competitive solicitation process results in a

[37] It is Con Edison's position that even though LIPA is not currently under PSC jurisdiction, Long Island customers should participate in the costs of the Plan to the extent that they also benefit from the implementation of the State's public policy determination.

third party transmission project being selected, the costs associated with each project will be recovered through a NYISO tariff schedule.

VII. HALTING MECHANISM

The November 30th Order requires that all Selected Projects move forward subject to a halting mechanism. The halting mechanism applies equally to the TOTS, the IPEC EE/DR Program, and to Selected Projects identified in the September Order. The halting mechanism included as part of the Plan enables the Commission to halt any TOTS and any Selected Project at any time up to and including December 31, 2014. It is Con Edison's and NYPA's view that to attract a satisfactory quantity of Proposals, it is necessary to impose a final date at which a project may be halted. Con Edison and NYPA believe project developers are unlikely to participate in this process if they face the risk that they may spend extraordinary time and resources to bring on-line quickly a large project only to be told that they are being halted at a very late stage of development and will receive only their out of pocket costs. Neither Con Edison nor NYPA can predict those market or other events that would cause the Commission to decide to halt a particular project.

Due to the unique nature of transmission projects, Con Edison and NYPA will need to purchase equipment that may not be usable for any other project. As such, the halting mechanisms reflect the fact that once equipment is ordered, Con Edison and NYPA must be able to recover 100% of the cost of such equipment, less any reductions available from cancellation provision in the procurement contract and realized salvage value. The halting mechanism also recognizes that in order to meet the In-Service Deadline, Con Edison and NYPA will need to start engineering the projects in April 2013 and start procurement activities as early as the fourth quarter of 2013. Thus, the halting mechanism must provide for the full recovery of costs incurred, as well as any contractual cancellation costs associated with such activities. It should also be noted that equipment procurement, engineering, and some construction activities will start even though not all of the required regulatory permits (environmental or community) will have been obtained as of this point in the project development schedule.

Recognizing the potential cost impacts to customers for the TOTS, Con Edison and NYPA can state the estimated costs they will incur for the TOTS at particular key points in time. Importantly, these estimates are based on conceptual project scopes and represent an order of magnitude reference for future project costs. As preliminary engineering and project tasks proceed, additional detail and certainty will support updated cost estimates. With respect to the RRT Line, the estimated costs of halting the project at the key points in time are shown in Table 7.1 below:

TABLE 7.1

Ramapo – Rock Tavern Line	Date Halted	Estimated Partial At Risk Cost*
(Project Total: $123,100,000)	9/30/2013	
	3/31/2014	
	12/31/2014	
* The "Estimated Partial At Risk Cost" includes only an estimate of the committed dollars and do NOT include any cancellation charges that would be imposed by the contractors and equipment suppliers. The "Estimated Partial At Risk Costs" will be adjusted at the time of halting to include these costs. These costs are based on a 2016 in-service date estimate.		

With respect to the SIU Project, the estimated costs of halting the project at the key point in time are shown in Table 7.2 below:

<u>TABLE 7.2</u>

Staten Island Un-bottling Project	Date Halted	Estimated Partial At Risk Cost*
(Project Total: $311,640,000)	9/30/2013	
	3/31/2014	
	12/31/2014	
* The "Estimated Partial At Risk Cost" includes only an estimate of the committed dollars and do NOT include any cancellation charges that would be imposed by the contractors and equipment suppliers. The "Estimated Partial At Risk Costs" will be adjusted at the time of halting to include these costs. These costs are based on a 2016 in-service date estimate.		

With respect to the MSSC Project, the estimated costs of halting the project at the key point in time are shown in Table 7.3 below:

<u>TABLE 7.3</u>

Marcy South Series Compensation Fraser to Coopers Corner Reconductoring Project	Date Halted	Estimated Partial At Risk Cost*
(Project Total: $76,000,000)	9/30/2013	
	3/31/2014	
	12/31/2014	
* The "Estimated Partial At Risk Cost" includes only an estimate of the committed dollars and do NOT include any cancellation charges that would be imposed by the contractors and equipment suppliers. The "Estimated Partial At Risk Cost" will be adjusted at the time of halting to include these costs. These costs are based on a 2016 in-service date estimate.		

NYPA will include a requirement in the RFP process that each Respondent provide the costs of halting its proposed project for the same dates shown above.

If the Commission halts a Selected Project, the project developer must mitigate its costs by prompt cancellation and liquidation of contracts, and by salvage sale of equipment already delivered or manufactured, and taking all other reasonable and necessary steps to mitigate net costs. The project developer will be compensated for its reasonable and prudent costs incurred in connection with the Selected Project but without any mark-up or premium.

VIII. THE COMMISSION SHOULD ESTABLISH A PUBLIC COMMENT PROCESS

The joint NYISO/NYTO Order 1000 compliance filing to implement the public policy requirements of Order 1000 defines a public policy requirement as:

> A federal or New York State statute or regulation, including a NYPSC order adopting a rule or regulation subject to and in accordance with the State Administrative Procedure Act, or any successor statute, that drives the need for expansion or upgrades to the New York State Bulk Power Transmission Facilities.[38]

By including the reference to the SAPA, the filing clearly intended that market participants and other stakeholders would have an opportunity to comment on the proposed public policy requirements and to participate in the debate with respect to projects that are submitted in response to the enunciated public policy. Unfortunately, the November 30th Order does not provide for an opportunity for market participants to comment on the specified public policy requirement of developing the Plan. Con Edison and NYPA agree that it is important for market participants to have the opportunity to weigh in on the important policy goals set forth in the November 30th Order, namely the need to develop and implement the Plan. Moreover, since the transmission projects put forth in this docket would be included in the NYISO's public policy

[38] October 11, 2012 joint NYISO/NYTO compliance filing.

planning process, orders issued by the Commission should facilitate that effort, including establishing a public comment period pursuant to SAPA. The need for this process was recognized by the Commission in its filing in FERC Docket ER13-102 (the FERC Order 1000 docket) when it stated that:

> The NYPSC is committed to working with the NYISO, NYTOs, and other interested stakeholders to develop a process that fits the [FERC's] Order 1000 framework and facilitates the appropriate implementation of State public policy goals.[39]

To enable the TOTS to move forward, the Commission must take certain steps, in addition to the issuance of its April Order, to establish that there is a public policy requirement that drives the need for upgrades to the New York State BPS. These steps include: (1) establishing a comment period in this docket consistent with the requirements of SAPA to review the public policy requirements associated with developing the Plan; (2) issuing a subsequent order establishing the public policy requirements that drive the need for transmission; and (3) determining that the TOTS and other Selected Projects meet the identified public policy requirements and should therefore proceed to request the necessary local, state, and federal authorization for construction and authorization of the Projects. This is the process that the Commission is required to undertake in order to satisfy its role in the NYISO's filed Order 1000 public policy planning process.

IX. STAKEHOLDER INPUT

During the course of developing this filing, Con Edison and NYPA held several meeting and conference calls with representatives of DPS staff and the NYISO in order to receive their

[39] December 11, 2012 *Answer of the New York State Public Service Commission* in response to protests of the joint NYISO/NYTO Order 1000 public policy planning process compliance filing, Docket ER13-102, p. 11. The joint NYISO/NYTO compliance filing is currently pending before FERC.

feedback on the calculations of the deficiency, reliability contribution of the TOTS and the overall Plan. On January 14, 2013, Con Edison and NYPA hosted an all parties meeting at Con Edison for the purpose of presenting the concepts and receiving stakeholder feedback with respect to the preliminary deficiency analysis and concepts to implement the requirements of the November 30th Order. At the January 14th meeting, several parties offered feedback on the proposed solutions, which Con Edison and NYPA took into consideration in the development of this compliance filing.

X. DESCRIPTION OF CON EDISON AND NYPA

Con Edison is a regulated public utility that is a subsidiary of Consolidated Edison, Inc., a holding company. In 2011, Consolidated Edison, Inc. had $39.2 billion in assets and $12.9 billion in revenues. Con Edison serves a 660 square mile area with a population of more than nine million people. In that area, Con Edison serves approximately 3.3 million electric customers, 1.1 million gas customers, and 1,700 steam customers. Con Edison provides electric service in New York City and most of Westchester County, gas service in parts of New York City and steam service within the borough of Manhattan. Con Edison has approximately 1,180 circuit miles of transmission, including 438 circuit miles of overhead and 742 circuit miles of underground transmission.

NYPA is a corporate municipal instrumentality and a political subdivision of the State of New York. NYPA owns and operates 16 generating facilities and about 1,400 circuit miles of high voltage transmission lines. The electricity it generates and purchases is sold to municipally owned utilities and electric cooperatives, as well as to a variety of business, industrial and public customers throughout the State. NYPA uses no tax money or state credit. It finances its operations through the sale of bonds and revenues earned in large part through sales of electricity.

Con Edison and NYPA have a significant interest in this proceeding and therefore request party status in this proceeding.

XI. CONTACT INFORMATION

The following people should be added to the official service list in this proceeding:

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XII. LIST OF EXHIBITS

This filing contains the following exhibits:

Exhibit A – Level of Energy Efficiency included in the model

Exhibit B – Detailed Description of the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring Project

Exhibit C – Detailed Description of the Second Ramapo to Rock Tavern 345 kV line

Exhibit D – Detailed Description of the Staten Island Un-bottling project

Exhibit E – RFP Respondent Information

Exhibit F - RFP Contract Terms

Exhibit G – Ongoing Demand Reduction Initiatives

XIII. CONCLUSION

As shown herein, the Plan is responsive to the requirements set forth in the Order and should be approved. There are, however, actions that the Commission needs to take to ensure that solutions are in place by the In-Service Deadline to address the potential closure of IPEC. Accordingly, for the reasons set forth herein, Con Edison and NYPA respectfully request that the Commission:

1. Issue an order in March 2013 (*i.e.*, the Interim Order) that:

a. Requests that NYPA issue an RFP for new generation and transmission solutions and identifies any changes the Commission desires to the general description of the RFP terms, conditions, process and timeline described in this Plan;

2. Issue an order in April 2013 (*i.e.*, the April Order) that:

   a. Directs Con Edison to begin the development of the RRT Line and the SIU Project, both of which will ultimately be transferred to and owned by the NY Transco, subject to the halting mechanism and cost recovery proposal set forth in the Plan;

   b. Requests that NYPA and directs that NYSEG begin the development of the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring Project, which will ultimately be transferred to and owned by the NY Transco, subject to the halting mechanism and cost recovery proposal set forth in the Plan;

   c. Approves this Plan including the cost recovery, cost allocation and halting mechanism proposals of the Plan;

   d. Directs Con Edison to implement its IPEC EE/DR program as set forth in the Plan with cost recovery and subject to halting; and

   e. Finds, on a preliminary basis, that the RRT Line; the MSSC Project; and the SIU Project are public policy projects that meet the public policy requirements of New York State as identified in the Order and the Blueprint;

3. Establish a public comment period in this docket pursuant to the SAPA to solicit comments on the proposed public policy enunciated in the Order;

4. Issue an order in September 2013 (*i.e.*, the September Order) that:

a. Selects a final set of transmission and generation projects to move forward subject to the halting, cost allocation, and cost recovery mechanisms set forth in this Plan;

b. Finds that developing and implementing an Indian Point Contingency Plan is a state public policy that drives the need for transmission;

c. Finds, to the extent that any of the TOTS are selected as final projects, that the RRT Line; the MSSC Project; and the SIU Project are public policy projects that meet the specified public policy needs of New York State as identified in the November 30th Order establishing this proceeding and the September Order;

d. Directs, to the extent that any of the TOTS are selected by the Commission as a final project, that it authorizes the recovery by Con Edison, NYPA and NYSEG of all reasonable and prudent costs incurred in pursuing each TOTS that is not otherwise recovered through the NYISO tariff pursuant to the cost allocation method described in the Plan;

e. Directs that each NYTO impacted by the Plan modify its retail cost recovery mechanisms for transmission and transmission-related costs, to the extent necessary, to provide that all NYISO transmission charges allocated to that individual NYTO as a result of the September Order will be recovered from that NYTO's retail customers;

f. Authorizes the recovery by Con Edison of all costs incurred in developing and implementing this Plan; and

g. Establishes a mechanism to enable NYPA to recover all costs incurred in developing and implementing this Plan.

Dated: February 1, 2013

Respectfully submitted,

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Exhibit A

IPEC EE/DR Program

To mitigate the need created with a retirement of the Indian Point Energy Center ("IPEC") by the In-Service Deadline, Con Edison has been collaborating with its partners at NYPA and NYSERDA, initiating preliminary discussions that have identified incremental energy efficiency, demand response, and combined heat and power ("CHP") initiatives that can be achieved prior to the In-Service Deadline ("IPEC EE/DR Program"). Achieving sufficient demand reduction through new incremental programs will help reduce the need for additional transmission and generating capacity which ultimately creates a long term avoided cost benefit for customers.

Con Edison proposes to achieve an additional peak demand reduction of 100 MW by the In-Service Deadline through new incremental EE and DR initiatives. The IPEC EE/DR Program will be additional to the suite of existing EEPS programs, with a focus on creating a holistic portfolio of solutions for reducing and managing loads primarily in large buildings. The IPEC EE/DR Program portfolio will include EE measures such as LED lighting, installed advanced control systems such as Building Management Systems ("BMS") and Energy Management Systems ("EMS"), and other controls that address roof-top, package terminal air conditioning ("PTAC"), room air conditioning (and similar non-central air conditioning units), installed advanced high efficiency HVAC and energy storage systems, and an extension of the steam air conditioning ("AC") incentives to all existing steam AC customers in addition to the Con Edison targeted Steam AC program initiated in Oct 2012. The advanced control systems (BMS, EMS) will allow for additional participation in Con Edison and NYISO demand response programs.

The range of programs envisioned under this portfolio approach would require the Commission to authorize in its April Order funding of at least $300 million to facilitate success.[1]

Building on existing expertise and infrastructure will be critical for expeditiously increasing market penetration. Con Edison anticipates that to achieve the stated amount of demand reduction in such a short period of time, projects will need to be incentivized at a level that rapidly encourages interest and participation by customers. It anticipates that all or most incentive levels in the IPEC EE/DR Program will need to be structured to ensure that payback periods are 12 months or less (*e.g.*, new equipment will save as much energy in one year as the customer paid for the equipment). The short payback period is necessary since the projected savings assume equipment replacement prior to its end of life; customers require higher incentives to replace existing equipment and move to the highest efficiency equivalency. In addition, short customer payback periods would help to ensure that equipment replaced at end of life would not be replaced quickly with standard (less efficient) equivalents, and encourage the highest efficiency replacement.

The need to keep pace with evolving markets and customer preferences necessitates a flexible portfolio design. Con Edison proposes to continually evolve programs, adjust incentives, and introduce new programs into the market to keep customers engaged. Con Edison anticipates that the proposed IPEC EE/DR Program opportunities would be offered to customers as peak demand reduction incentives to complement or enhance existing EEPS incentives. Thus, the incremental 100 MW of demand reduction that is coincident with the system peak must be viewed as a "net" goal, making the need for flexible innovative programs even more critical to

[1] There may be joint opportunities with NYSERDA to achieve these incremental energy efficiency increases that contribute to peak load reductions. The Commission may choose to evaluate NYSERDA funding levels in order to achieve the incremental goal.

minimize the impact on existing programs and keep pace with new and evolving demand reduction opportunities.

Con Edison envisions that 100 MW of permanent peak demand reduction would be achieved through a customer incentive program funded through a separate surcharge that would sunset at the end of a four-year period (including time for administrative and operations completion of the program). Con Edison would recover actual expenses from the IPEC EE/DR Program through an electric surcharge on customer electric bills in the calendar quarter immediately following the calendar quarter in which they were incurred. As shown in TABLE A.1 below, projected expenses are expected to begin in the 2nd quarter of 2013 for administrative and marketing functions and conclude in the 3rd quarter of 2016.

TABLE A.1

	2013			**2014**				**2015**				**2016**		
Forecast Quarter	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**
TOTAL GROSS Projected Peak MW Cumulative	0	0	0	2	11	25	34	43	58	77	100	100	100	100
TOTAL Projected Cumulative Expenditures ($ Million)	0.2	0.5	6	13	28	50	70	105	157	208	249	280	295	300
Projected Quarterly Expense ($ Million)	0.2	0.3	5.5	7	15	22	20	35	52	51	41	31	15	5

In the event that the Commission terminates this IPEC EE/DR Program prior to its approved conclusion through a halting order, Con Edison would continue collection of funds necessary for fulfillment of all customer commitments in place at the time of program halting and terminate the IPEC EE/DR Program from that point forward. Con Edison does not believe that reinstating programs after termination would be a viable option because of the time needed to ramp programs up and the attendant uncertainty that termination and subsequent reinstatement introduces into the market.

Con Edison does not believe that the Total Resource Cost ("TRC") test currently employed by EEPS should be used in the IPEC EE/DR Program to evaluate the cost effectiveness of EE measures. The TRC test is based on a multitude of variables that do not fully capture the environmental and societal value from permanently reducing the need for fossil generation capacity. The test also requires extensive communication between parties, and must be constantly recalculated during all components of program design. Each of these would hamper the achievement of demand reductions from the programs by the In-Service Deadline.

Achieving the IPEC EE/DR Program goals will require a regulatory structure that facilitates flexibility in design and expedited implementation. As such, and as an alternative to the traditional TRC test that is employed in the current EEPS programs, Con Edison proposes a flexible portfolio design to allow Con Edison to evaluate programs and projects on a rolling basis. The analytical framework for evaluation would be based on an efficiency cost curve (*e.g.*, $/ KW-saved) that is less than or equal to the total cost of building and running new generation, transmission, and distribution assets. This framework will be similar to that used in the current targeted demand side management program, but will include consideration of long term avoided costs of transmission and generation. Con Edison proposes to create a portfolio report of the programs and projects accomplished, measures used, dollars expended, and dollars committed that will be delivered to Staff on a quarterly basis.[2]

Recognizing the need for rapid and innovative action by Con Edison, the Commission should authorize a shareholder incentive that is more effective than that provided for Energy

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[2] In the first quarterly report, Con Edison will identify the methodology for calculating and tracking incremental demand reductions that result from the IPEC EE/DR Program.

Efficiency Portfolio Standard ("EEPS") programs and provides a financial incentive designed instead to provide long term benefits. Con Edison proposes that the Commission consider the implementing one of the following alternative incentive structures, or other similar approach, that would be unique to this portfolio:

1) Con Edison will be authorized a rate of return on the total investment in the IPEC EE/DR Program for which the cost of demand reduction is less than the cost of new generation ($/kW);
2) Con Edison's IPEC EE/DR Program expense is treated as if it were a capital expense, and granted a rate of return based on a percentage of the most recent completed rate case; and
3) A pre-determined incentive value is agreed upon prior to IPEC EE/DR Program implementation, and is based on preliminary cost estimates and the most recent rate of return on capital; and upon expiration of the IPEC EE/DR Program (either through time or set by budget), the utility is granted a commensurate percentage of incentive based on degree of success in achieving reductions (*e.g.*, achieving 80% of target yields 80% of incentive or some other such agreed upon scaling).

Con Edison expects that the portfolio of programs identified below will experience upfront administrative hurdles and market barriers that will need to be overcome. Adequate time must be given to launch, procure contracts, and begin implementation prior to the closure of IPEC. If the net 100 MW of demand reduction are to be relied upon prior to IPEC's closure, Con Edison will need to secure an approval to proceed with funding, program development, and implementation by April 2013.

The IPEC EE/DR Program will focus on measures that have the greatest opportunities for success in a short timeframe and will most readily complement the existing EEPS programs to yield cost effective demand reductions. These opportunities are predominantly found in large building lighting systems, HVAC, and control systems.

The IPEC EE/DR Program also recognizes there exist opportunities to work with NYSERDA to incentivize retail sales of energy efficient customer-run appliances and equipment that are run during times that are coincident to the transmission peak (*i.e.*, window AC units).[3] To the extent that NYSERDA's efforts are applied toward infrastructure planning through the IPEC EE/ DR Program, NYSERDA would provide access to all project data such as the type, size and location of the measures and projects it undertakes in Con Edison territory.

The table below outlines the range of programs that could be implemented:

TABLE A.2

Sample Measure[4]	***Permanent EE/DR MW Savings***[5]	***Description***	***Obstacles to Implementation***
LED Lighting	40	• Replace T5, T8, T12 with LED • Replace interior and exterior • Replace CFL, Halogen with LED • Controls	• Availability of bulbs, availability of ballasts and fixtures • Time frame for next generation LED bulb • Quality of light • Potential cannibalization of current EEPS
BMS, EMS and other	12	• Install advanced control systems	• Life of current system not exceeded • Cost of advanced systems • System compatibility, equipment and cabling footprint • Potential cannibalization of current EEPS
HVAC	20	• Install advanced High efficiency systems	• Life of current system not exceeded • Cost of hi efficiency systems

[3] To achieve the IPEC EE/DR Program goals, NYSERDA incentives would have to be structured with a goal of achieving a net reduction in electricity demand.
[4] Sample Measures listed are not intended to be exclusive.
[5] Permanent EE/DR MW Savings should be treated as approximations based on market potential as of mid 2011; these numbers are subject to change as final program design, implementation, and market penetration progress.

		• Controls	• Equipment and ductwork footprint • Potential cannibalization of current EEPS
Steam AC	8	• Extend steam AC incentives to all existing steam AC customers	• Life of current system not exceeded • High cost of steam • Market availability of steam AC chillers
Other	20	• Other permanent Efficiency and Demand Response measures	

In addition to the examples and programs cited above, Con Edison believes that new and innovative program designs may create additional opportunities for demand reduction after the initial IPEC EE/DR Program portfolio has been crafted. Accordingly, Con Edison reiterates the need to maintain flexibility in implementing its portfolio, and the ability to quickly assess and pursue new program opportunities to achieve maximum demand reduction at a reasonable cost.

Exhibit B

Detailed Description of Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring Project

Detailed Description of Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring Project

I. Project Description:

The Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring ("MSSC") project will add switchable series compensation to increase power transfer by reducing series impedance over the existing 345kV Marcy South lines. Specifically, the project will add 40% compensation to the Marcy-Coopers Corners 345kV line and 25% compensation to the Edic-Fraser / Fraser-Coopers Corners 345kV line through the installation of capacitors. This project will reconductor approximately 21.8 miles of the NYSEG-owned Fraser-Coopers Corners 345kV line (FCC-33) with 2784 ACCC conductor using existing towers and will involve upgrades at the Marcy, Fraser, and Coopers Corners 345kV substations. The project will increase thermal transfer limits across the Total East interface and the UPNY/SENY interface and will also provide a partial solution for system reliability should IPEC retire.

II. Use of Existing Rights-of-Way:

Subject to confirmation of the on-going conceptual engineering studies, it is not anticipated that additional property will be required for the re-conductoring of the approximately 21.8 miles on the FCC-33 line or the installation of the capacitors in the substations

III. Preliminary Engineering Status:

Preliminary engineering is currently underway to:

- Provide a complete definition of system equipment;
- Develop a footprint and physical layout for the series compensation;
- Provide field walk downs, site surveys, and fully specify location options;

- Detail fully compliant options for protection and control of the series capacitors and the lines in the substation yards and control rooms;
- Confirm the adequacy of structures and costs to re-conductor approximately 21.8 miles of transmission line FCC-33;
- Provide cost estimates of detailed engineering, material testing, commissioning, and other modifications.

In the near future we expect to commence Transient Recovery Voltage Calculations, Electrostatic and Electromagnetic Calculations, and Sub-Synchronous Resonance Analysis.

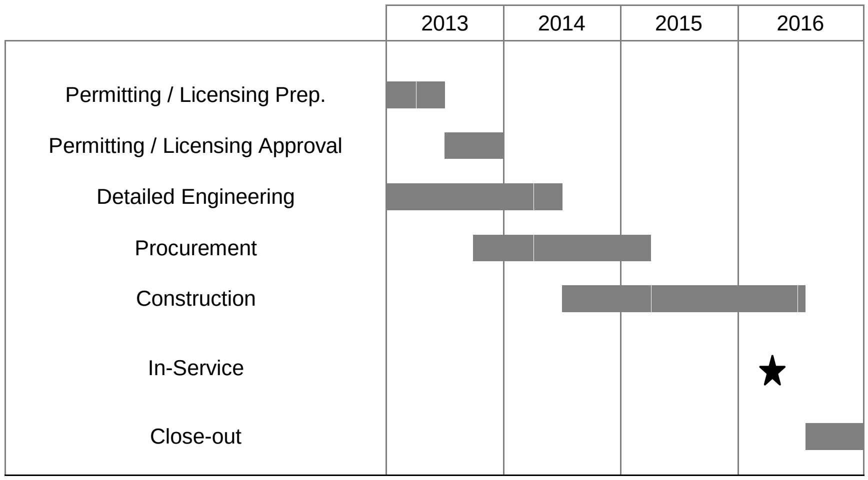
IV. Interconnection Status:

The MSSC project has NYISO queue position 380 and the development of the System Impact Study is currently underway.

V. Estimated In-Service Date:

Assuming that licensing and permitting are completed by the end of 2013 and provided that there are no delays or complications in procurement or construction, the MSSC project could be in service by June 2016. Conceptual/preliminary engineering has begun and, upon its completion, more detailed engineering and environmental studies necessary to support regulatory approval applications will be undertaken.

VI. Estimated Project Schedule:



VII. Preliminary Cost Estimate (2016 dollars): $76 million

Redacted

Exhibit C

Detailed Description of the

Second Ramapo Rock Tavern 345kV line

I. Project Description:

The project will establish a second 345kV line from the Ramapo 345kV substation to the Rock Tavern 345kV substation. The project will increase the import capability into Southeastern New York, including New York City, during normal and emergency conditions and will provide a partial solution for system reliability should Indian Point Energy Center retire. The project will be located in Orange and Rockland Counties in New York along the existing right-of-way of the existing Con Edison 345kV line 77 (Ramapo to Rock Tavern). The transmission line terminals are located in NYISO Zone G.

Central Hudson's Rock Tavern 345kV substation will be connected to Con Edison's Ramapo 345kV substation by performing three concurrent system upgrades. The first upgrade would convert O&R's Feeder 28 (Ramapo 138kV substation to Sugarloaf 138kV substation) from its current operating voltage of 138kV to 345kV by reconnecting Feeder 28 at the Ramapo 345kV substation. The second upgrade would be to create a Sugarloaf 345kV substation and add a 345 / 138kV step-down transformer between the Sugarloaf 345kV and 138kV substations. The third upgrade would be to install a 345kV line between Rock Tavern and the Sugarloaf 345kV substation utilizing bundled 1590 ACSR (2 x 1590 ACSR) conductor.

II. Use of Existing Rights-of-Way:

The project will utilize the existing right-of-way along the existing transmission route from Ramapo to Rock Tavern 345kV substations. No additional land rights are required to construct the substation upgrades at either the Ramapo substation or the Rock Tavern substation in order to connect the new 345kV line. Siting of the property for the Sugarloaf 345kV substation has not been completed, but it is anticipated this substation will utilize existing property owned by O&R in the vicinity.

III. Interconnection Status:

The second Ramapo to Rock Tavern 345kV line was submitted to the NYISO interconnection process and has queue position 368. A System Impact Study was completed and approved by the NYISO Operating Committee on August 16, 2012. No further action related to the NYISO interconnection process is required.

IV. Permitting Status:

Con Edison received an Article VII Certificate in 1972 which authorized the construction of the Ramapo to Rock Tavern transmission route with towers that could accommodate two 345kV circuits, although only one circuit was needed at that time. The Commission Order granting the Certificate allowed Con Edison to install the additional circuit with prior notice to the Commission. In 2010, Con Edison and O&R jointly petitioned the Commission to allow O&R to install proposed Feeder 28, a second circuit on the existing towers along the transmission route from Ramapo substation to Sugarloaf substation. The Commission allowed O&R to install proposed Feeder 28 under the original Article VII Certificate issued in 1972. Given the passage of time since the Certificate was granted, the Commission requested that O&R submit an updated Environmental Management and Construction Plan ("EM&CP") presenting an assessment of potential environmental impacts associated with the installation of the proposed additional circuit. A Commission Order transferring a portion of the Article VII Certificate to O&R for installation of Feeder 28 from Ramapo to Sugarloaf, and approving the updated EM&CP, was issued on January 24, 2011 (Case 10-T-0283).

Based on the experience with Feeder 28, the NYTOs expect that the only key permitting/approval requirement for the second Ramapo to Rock Tavern transmission line, also called Feeder 76, is Commission approval of updated EM&CP for the project. This EM&CP

would address the Sugarloaf substation to Rock Tavern substation section of the existing right-of-way, including any incremental physical reinforcements needed to bring the existing transmission towers to current standards. The EM&CP would also address the proposed Sugarloaf 345kV substation and the incremental additional equipment required at Ramapo and Rock Tavern substations, and would be equivalent in content and level of detail to the Feeder 28 EM&CP which was approved by the Commission in January 2011.

The Feeder 76 EM&CP would present an assessment of potential environmental impacts associated with the installation of the proposed additional circuit on the existing towers, and with the construction and operation of the proposed Sugarloaf 345kV substation and the incremental additional equipment at Ramapo and Rock Tavern substations. The EM&CP would identify the governing Federal/State/Local permitting/regulatory requirements, and then evaluate the Feeder 76 project components against the substance of those requirements. This effort would include evaluation of Feeder 76 predicted magnetic field levels against the Commission's interim 200 mG standard, and consultation with other State and Local agencies on matters within their jurisdiction, for example with NYSDEC regarding protection of State endangered/threatened species.

The following sets forth a preliminary list of major Federal, State and Local permits/approvals which are expected to be filed separately from the EM&CP:

1) Federal permits/approvals governing Feeder 76 project activities in any Federally-regulated wetlands and water bodies:

    The existence and extent of any Federally-regulated wetlands or water bodies would be identified during preparation of the Feeder 76 EM&CP. Feeder 76 installation activities affecting any Federally-regulated wetlands and water bodies would likely be permitted under the Clean Water Act Section 404 Nationwide Permit No. 12 ("NWP 12"), which was developed to cover land clearing and similar activities associated with installation of utility line crossings of wetlands and water bodies. NWP 12 provides authorization for such activities provided the cleared area is kept to the minimum necessary and preconstruction contours are maintained. The eligibility of Feeder 76 installation activities for NWP 12 would be confirmed during preparation of the EM&CP, and the required Pre-Construction Notification ("PCN") prepared and filed with the U.S. Army Corps of Engineers.

2) Federal requirements governing endangered/threatened species and archeological/cultural resources, which may require that protective measures be employed during installation of Feeder 76:

   During preparation of the EM&CP, the potential for Feeder 76 installation activities to affect such resources would be identified, any necessary Federal agency consultation would be performed, and any necessary protective measures would be developed.

3) State permits/approvals governing Feeder 76 project activities in any State-regulated wetlands and water bodies:

   The existence and extent of any State-regulated wetlands (defined differently than Federally-regulated wetlands) and State-regulated water bodies would be identified during preparation of the Feeder 76 EM&CP. NY Transco would likely seek to follow the recent Con Edison / O&R Feeder 28 experience for installation activities affecting State-regulated wetlands and water bodies. Briefly stated, for Feeder 28 O&R was given authorization by NYSDEC to conduct feeder installation activities in accordance with a NYSDEC General Permit issued to O&R under Environmental Conservation Law Article 15 – Protection of Waters and Article 24 – Freshwater Wetlands. The eligibility of Feeder 76 activities for coverage under Con Edison/ O&R's corresponding NYSDEC General Permit would be identified during preparation of the EM&CP, and the required notification package submitted to the NYSDEC.

4) Coverage under NYSDEC SPDES Construction Storm Water General Permit:

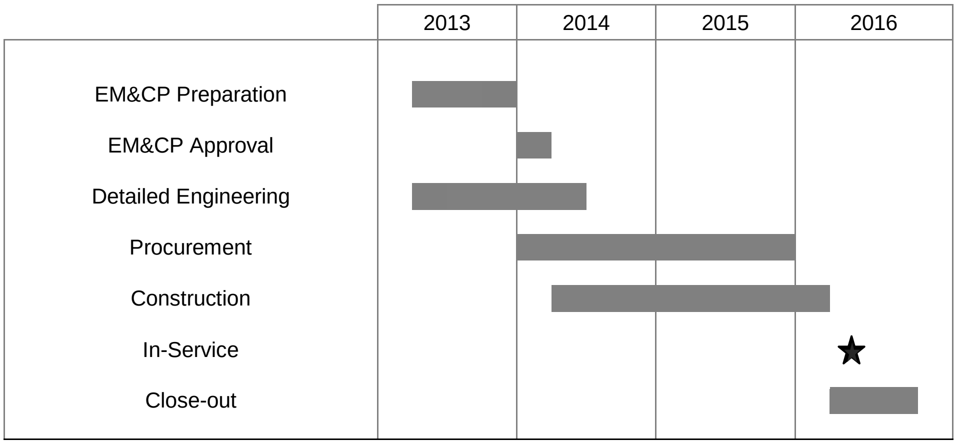
   The Feeder 76 EM&CP preparation effort would include a State Pollutant Discharge Elimination System (SPDES) Construction Storm Water Pollution Prevention Plan (SWPPP) as a component of the EM&CP, and a Notice of Intent for filing by NY Transco with NYSDEC.

5) State and Local Transportation and Utility Crossing permits/approvals:

   The Feeder 76 installation activities have the potential to impact roads, highways, railroads and other existing utilities. The EM&CP preparation process would identify each crossing affected and outline construction practices ensuring that vehicular, pedestrian or rail traffic is not adversely impacted. The appropriate state and local officials would be contacted and required permits for crossing and construction access would be obtained. For New York State highways this would require preparation and submission of NYSDOT Highway Work Permit applications, and Maintenance & Protection of Traffic Plans.

V. <u>Estimated In-Service Date</u>: June 2016

VI. Estimated Project Schedule[6]:



VII. Preliminary Cost Estimate (2016 dollars): $123 million

[6] The schedule reflects an accelerated EM&CP preparation and approval process to meet the target in-service date of June 2016, and is dependent on receiving an order from the Commission to proceed with the project in April 2013 in order to meet the estimated milestones.

Redacted

Exhibit D

Detailed Description of the Staten Island Un-Bottling Project

Detailed Description of the Staten Island Un-bottling Project

I. Project Description:

Un-bottling Staten Island generation and transmission resources will require the installation of a new 345kV feeder and the forced cooling of existing four 345 kV feeders. The new feeder would mitigate a contingency within New York City by installing a new double leg feeder into new positions at the Goethals and Linden substations. The forced cooling of the existing four 345 kV feeders will increase transmission capacity between Goethals, Gowanus, and Farragut substations. The Project would be located in Staten Island and Brooklyn, New York and Union County (Linden), New Jersey. This project is located in NYISO Zone J.

The new 345kV double circuit solid dielectric cable system interconnecting the Goethals substation to the Linden substation will be approximately 1.5 miles. The feeder will cross Arthur Kill River to get from Staten Island, NY to Linden, NJ. Both substations will need new 345kV breakers and bus modifications to establish new bus positions for the new feeder and to maintain feeder separation. Linden Substation is an SF6 (sulfur hexafluoride) station that requires SF6 equipment to expand the station. Although Goethals Substation is an open air substation, due to limited space, the new bus position needs to be established using SF6 equipment.

The project also includes the installation of ten (10) refrigeration plants to increase transmission capacity between Goethals, Gowanus, and Farragut substations on the four 345 kV feeders 25, 26, 41, and 42. Six of these plants will be installed in support of feeders 25 and 26; one each at Gowanus and Goethals Substations and four along the route of the feeders. The plants along the route need to be sited equidistant to each other and the interconnecting stations. One of these locations is the current Bay Street property, which will hold two cooling plants.

The other location will hold another two plants in support of feeders 25 and 26 will need to be acquired. The next four plants will be installed in support of feeders 41 and 42; two each at Gowanus and Farragut Substations.

II. Property Acquisition:

The first two of the six cooling plants will be located at the terminal stations of feeders 25 and 26. The next two of the six cooling plants required to cool feeders 25 and 26 will be installed at the Bay Street property. The last two cooling plants will require the acquisition of new property. This new property needs to be located as close as possible to the route of feeders 25 and 26, large enough to hold two refrigeration plants, and needs to be located at the midpoint of Goethals Substation and the Bay Street plant. Acquisition of the property has not been completed. The property must be procured to accommodate the service date of May 2016.

III. Interconnection Status:

On January 18, 2013, NYISO pronounced, per Section 2.4.2 of the NYISO Transmission Expansion and Interconnection Manual, that a System Impact Study is not required for the proposed modifications.[7]

IV. Permits:

The following sets forth a preliminary list of major Federal, State and Local permits/approvals which are expected to be filed (additional permits may also be required). These filings and reviews will take approximately six months to one year to complete. The exact timeframe would be determined through a pre-application conference with the U.S. Army Corps of Engineers (USACE), the New York State Department of Environmental Conservation

[7] The Staten Island Un-bottling project is contingent on the use of the Co-Gen position at the Linden Substation.

(NYSDEC), and the New Jersey Department of Environmental Protection (NJDEP), to discuss the project and confirm permitting requirements.

1. U.S. Army Corps of Engineers (USACE):
    a. Permitting is needed for the new cable installation beneath the Federally-regulated water body (Arthur Kill) and through the Federally-regulated wetlands
    b. Potential USACE permits needed:
        i. USACE Nationwide Permit (NWP) 12, which is only applicable for activities that have minimal adverse effects on the environment
        ii. USACE Section 10 of the Rivers and Harbors Act of 1899, Section 404 of the Clean Water Act
            1. An individual permit would trigger an environmental impact review under the National Environmental Policy Act (NEPA)
2. Article VII Exemption and Individual Permits: The PSC issued a Declaratory Ruling in November 1990 allowing the Cogen Tech interconnection to be exempt from the Article VII process. This 1990 determination would need to be reconfirmed with the PSC for the new parallel feeders to be installed.
    a. If the new Staten Island Transmission Upgrade is also exempt from Article VII, individual permits would need to be filed and an environmental impact review would need to be conducted under the Federal National Environmental Policy Act (NEPA) and NY State Environmental Quality Review (SEQR) process.

b. Potential individual permits needed:

    i. NYSDEC Environmental Conservation Law Article 15 (Use and Protection of Waters) and Article 25 (Tidal Wetlands)

    ii. NYSDEC and NJDEP State Pollutant Discharge Elimination System (SPDES) Stormwater Pollution Prevention Plans (SWPPPs) for the new cable installation in the bed of the Arthur Kill and State-regulated wetlands

    iii. NJDEP Waterfront Development Law, Wetlands Act

    iv. City of New York and City of Linden construction-related approvals triggered by the new cable installation

    v. NJ Turnpike Authority permits, dependent on the route of the parallel feeders

3. NYC Zoning/Land Use Approval:

    a. Land use approval needed for cooling plants proposed outside existing Con Edison substations and Linden Cogen facilities

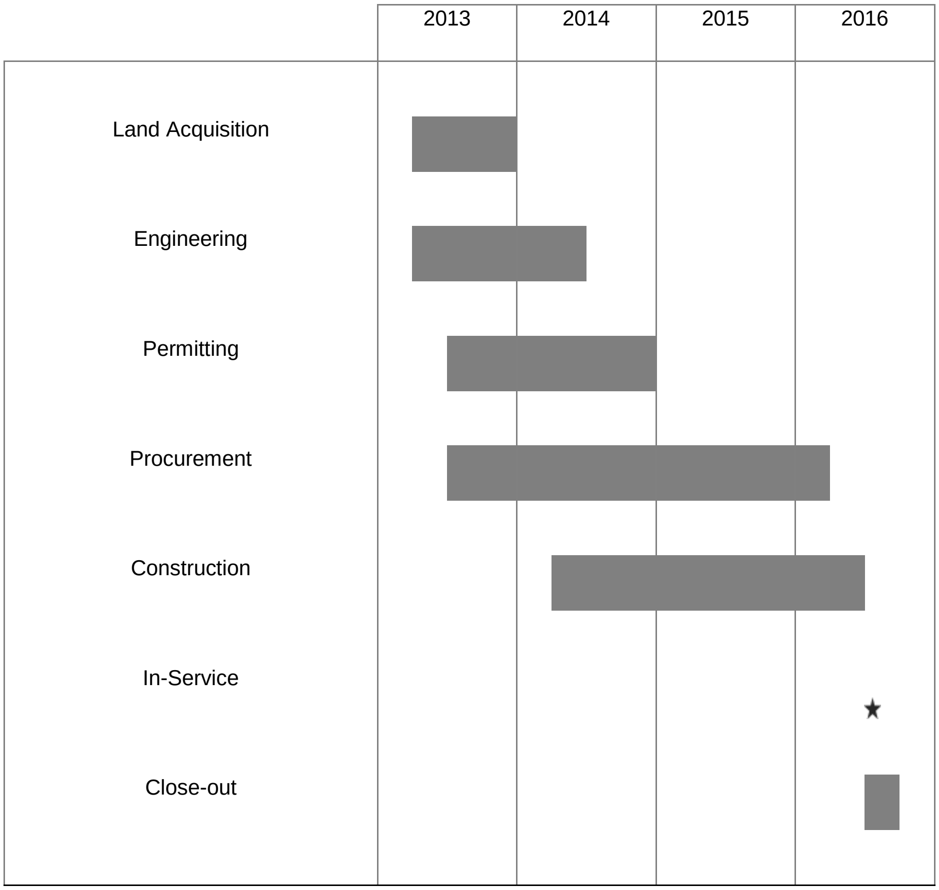
    b. An application will need to be filed with the NYC Board of Standards and Appeals (BSA) and the local Community Board. An environmental impact review will also need to be submitted under the City Environmental Quality Review (SEQR as implemented by NYC)

    c. Once the approval process has been completed, Con Edison would need to apply for and obtain the necessary NYC construction approvals

V. <u>Estimated Service Date:</u>

The proposed service date is May 2016.

VI. Estimated Project Schedule:



VII. Preliminary Cost Estimate (2016 dollars): $312 million

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Redacted

Exhibit E

RFP Respondent Information

RFP Respondent Information

Respondents to the RFP will be required to provide relevant information which may include the following information:

- Cover Letter
  Statement that Respondent's proposal meets following Threshold Criteria
  i. Statement that pricing is firm through December 31, 2013
  ii. COD deadline of June 2016
  iii. Project provides incremental generation capacity and/or transmission capacity (i.e. not included in the 2012 Reliability Needs Assessment)
  iv. Generation project provides a minimum of 75 MW (UCAP)
  v. Point of injection and withdrawal (transmission) or interconnection (generation)
  vi. Signed by individual authorized to bind the Respondent contractually

- Contact Information:
  Proposals must contain:
  i. Company name, address and telephone number (including name, address, telephone number, and e-mail address of the contact person for Respondent in connection with its Proposal)
  ii. Legal status
  iii. Ownership status
  iv. Guarantor information
  v. For consortium proposals the consortium must provide information on its legal form, similar information as above for each member, and identify the Lead Member (the member responsible for providing all financial security, executing the resulting contracts, and providing proposed products)

- Project Team & Experience:
  Respondents should provide information demonstrating competence and experience in developing, managing, and operating similar types of projects. Proposal must detail:
  i. Business and history
  ii. A description of the project management team
  iii. Experience in developing, financing, constructing, and operating electric generating plants and/or transmission facilities
  iv. Familiarity and experience with NYISO requirements and its membership status with the NYISO and/or commitment to become a member
  v. Existing electric facilities owned and/or operated by Respondent—including size, COD, location
  vi. Respondent's financial condition and creditworthiness.
    a. NYPA will enter into an NDA with Respondents whose financial statements are not public
  vii. Financing plan

- Disclosure Statements

  Proposals must contain disclosure of any instances in the last five years where Respondent, any of its officers, directors or partners, any of its affiliates, or its proposed guarantor (if any):

  i. Defaulted on, or was deemed to be in noncompliance with, any obligation related to the sale or purchase of power (capacity, energy and/or ancillary services), transmission, or natural gas, or was the subject of a civil proceeding for conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions, or collusive bidding or other procurement- or sale-related irregularities; or
  ii. Was convicted of (i) any felony, or (ii) any crime related to the sale or purchase of power (capacity, energy and/or ancillary services), transmission, or natural gas, conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions, or collusive bidding or other procurement- or sale-related irregularities.

- Financial Capacity to Complete and Operate the Proposed Project
  i. Provide a detailed description of proposed short- and long-term financing arrangements. A list of all equity partners, sources of equity and debt, debt structure.
  ii. Demonstrate that financial arrangements from Respondent's parent or affiliate are sufficient to support the project through construction and the contract term.
  iii. Describe proposed capital structure for the project.
  iv. A schedule showing all major projects developed and financed by Respondent in the past 10 years.
  v. Provide details of any events of default or other credit issues associated with all major projects listed above.
  vi. Identify proposed guarantor(s) for the Project and provide documentation of the guarantor’s creditworthiness including the three most recent audited financial statements of the guarantor).
  vii. Provide information concerning the Respondent’s financial condition and evidence of creditworthiness including:
     a. Audited financial statements for its three most recent fiscal years; or
     b. Audited financial statements from Respondent’s parent, if Respondent does not have such financial statements; or
     c. Statement describing why the statements in either i) or ii) cannot be provided and provide alternate information to demonstrate Respondent’s financial capacity to complete and operate the proposed project.
  viii. Include four references from prior projects developed by the Respondent that employed financing arrangements similar to the arrangements contemplated by the Respondent for the project

- Project Specific Information:
  For all proposed projects provide a project implementation plan, including detailed schedule, and give a general overview of all aspects of the plan from commencement of construction to testing and commissioning of the Project. Please include:

  i. Timelines for selection and award of Engineering, Procurement and Construction agreements
  ii. Timelines for fabrication and procurement of equipment requiring significant lead times, or demonstration that such activities can be timely completed
  iii. Equity and debt financing plans;
  iv. EPC Contractor experience (if available);
  v. Other Contractors experience (if available);
  vi. A description of how the project will interconnect with the NYS Bulk Power Transmission Facilities
  vii. If applicable, a description of the rights of way to be used or acquired
  viii. If applicable, the thermal capacity and impedance ratings of the line
  ix. The required substation and protection additions or modifications required including a list of major equipment and their ratings
  x. Status of site control and a description of the property that would need to be acquired for the project
  xi. A list of anticipated Electric System Upgrade Facilities
  xii. Status of the project in the NYISO's Interconnection Queue
  xiii. A major milestone schedule

  For generation projects –
  a. Complete detailed generation data sheet
  b. Project location
  c. Project size in MW (Note: projects must be a minimum of 75 MW (UCAP)
  d. Fuel Supply plans:
  e. Access to and interconnection with gas pipeline facilities;
  f. Identify and describe any manual or automated fuel switchover capability;
  g. Gas supply and transportation; and
  h. For projects having non-firm gas transportation: Fuel oil storage for a minimum 5 days of continuous full power operation including plans for liquid fuel procurement, supply and transportation

  For transmission projects –
  a. Complete detailed transmission data sheet
  b. Points of withdrawal and injection
  c. Site plan
  d. System area one-line
  e. Detailed substation one-lines
  f. Substation plot plans
  g. Transmission route plan

- Environmental and Permitting:

i. A list of all regulatory approvals required from state, federal and local licensing and environmental regulatory agencies, and a schedule for applications and expected regulatory approvals
ii. If planning to permit project under SEQRA, statement of how project qualifies under SEQRA rather than Article 10
iii. Environmental impact impacts and externalities
    a. Emissions (NOx, SO2, CO2)
    b. Cooling water
    c. Land use impact
iv. Environmental justice issues

- Contract Exceptions
    i. Provide a detailed list of all contract exceptions
    ii. Provide a redline Word document markup of NYPA draft contract relevant to project

- Project Costs:
    i. Respondents will submit detailed capital cost estimate breakdowns, including a proposed spending schedule, for each segment of the project and must include the following at a minimum:
        a. Licensing/permitting
        b. Engineering
        c. Construction labor
        d. Major equipment
        e. Real estate acquisitions and rights of ways
        f. Overheads
        g. Contingencies
    ii. Description of project assumptions used for the basis of the project capital costs
    iii. Halting costs
        a. Dates and spending thresholds according to a schedule that will be defined in the RFP

- Pricing:
  For transmission projects, Respondents will provide a single price (in $/month) to cover the full term. In addition, provide a list of assumptions used in calculating the pricing, which shall include but not be limited to:
    i. Cost of capital
    ii. Annual operations and maintenance costs
    iii. Property Taxes
    iv. Escalation rate

  For generation projects, Respondents will submit pricing in two forms.
    a. The first will be in the form of a contract for differences (“CFD”) in which the total cost of the project is fixed, but the monthly payment due will be reduced by the amount of the market revenues available to the project for that month. Pricing must be in total dollars per month.

b. The other required bid form will be as a contract that states the fixed amount that the project developer requires on a dollar per month basis for support in addition to the market revenues it expects to realize. This is similar to the approach employed in the Renewable Portfolio Standards venue.

In addition, provide a list of assumptions used in calculating the pricing, which shall include but not be limited to:

a. Cost of capital
b. Annual operations and maintenance costs
c. Property Taxes
d. Escalation rate

- Community outreach plan:
  Respondents should provide the following:

  i. A detailed description of Respondent's planned approach to managing the potential impact on affected communities and interested parties.
  ii. A description of any community outreach activities that Respondents have conducted prior to submitting its proposal in this RFP.
  iii. In the event that Respondent's proposal is selected, a description of Respondent's planned activities after selection and how it would coordinate such activities with Con Edison/NYPA, including:
     a. A description of the plan for educating affected communities about the Project.
     b. Plan to secure community input about Project on an ongoing basis.
     c. Plan to integrate community needs and concerns into Project planning.
     d. Plan for using local labor and materials.
     e. An explanation of the economic development opportunities associated with Project to the community.
     f. Plan to prepare mitigation plan associated with local siting and permitting issues for community review.

- Minority/Women-Owned Business Enterprise
  - Description of the approach for use of NY State certified M/WBEs in connection with the project

- Economic development benefits:

Respondents should describe the following:

  i. Impact of the project on the State and local economy.
     - Construction jobs
     - Long term jobs

Exhibit F

RFP Contract Terms

Major RFP Contract Terms

The RFP will include a form of PPA that includes standard commercial terms and conditions. Set forth below is a listing of indicative provisions that will be included, with special attention to proposed milestone dates. We anticipate that the September Order will impose similar terms and conditions any Selected Transmission Projects.

i. General Definitions
ii. Representations and Warranties
iii. Obligations and Deliveries
iv. Remedies for Failure to Deliver or Receive
v. Payment Provisions
vi. Credit and Collateral Provisions Related to Achieving Milestones and ICAP Obligations
vii. Project Milestones
    a. Design Completed
    b. Site Studies and Surveys Completed
    c. NYISO Feasibility Study Completed
    d. NYISO Impact Study Completed (SIS or SRIS)
    e. NYISO Facilities Study Completed
    f. Posting of Security for SUF and SDU Costs
    g. Interconnection Agreement Executed and Filed at FERC
    h. Permit Applications Submitted
    i. Permitting and Regulatory Approvals Received
    j. Construction Contract Executed
    k. Notice to Proceed Issued
    l. Interim Construction Milestones Achieved
    m. Commercial Operation Achieved
viii. Halting Mechanism and Cancellation Cost Recovery
ix. Confidentiality Provisions
x. Indemnity
xi. Limitations on Liability
xii. Force Majeure

Exhibit G

Ongoing Demand Reduction Initiatives

Con Edison has also been collaborating with its partners at NYPA and NYSERDA to identify incremental EE, DR, and CHP initiatives over and above what is already included in the 2012 RNA that can be achieved prior to the In-Service Deadline. There exists a combination of programs with funding that is not currently included in the Updated 2012 RNA which is still being reconciled.[8] The Plan will ultimately incorporate these during the evaluation process that determines the final set of transmission and generation solutions.

In late 2012, Con Edison expanded its Targeted DSM program, offering incentives to retain steam air conditioning ("AC") customers in targeted electric networks which will result in 8 MW of incremental peak load reduction by 2016.

NYPA has been working with several New York City and State Agencies, including those affected by Governor Cuomo's recently announced Executive Order 88 "Build Smart NY," to identify incremental demand reductions based on long term capital planning and expects to achieve an additional 15 MW peak demand reductions not accounted for in the 2012 RNA (some projected achievements from Build Smart NY are already included in the 2012 RNA). This represents work associated with aeration and de-watering system upgrades at wastewater treatment plants in New York City as well new efficiency opportunities identified in master energy plans that are envisioned for university campuses in New York City. Equipment at many of the wastewater treatment plants has outlived its useful life and there has been significant advancement in the technology that can be employed to further reduce high level energy consumption at these facilities. Campus-wide ASHRAE Level II audits will help identify capital energy efficiency retrofits. In addition to energy efficiency measures, the audits will help to

[8] The impact could be as much as 88 MW once the programs in-progress are fully identified and accounted for. These programs are in addition to the 100 MW incremental demand reduction to be achieved through the IPEC EE/DR Program.

identify opportunities for cost effective on-site renewable generation and potential for combined heat and power projects. Additionally, NYPA has been working with customers to install CHP projects and expects that 15 MW will be placed in service by the In-Service Deadline.

Lastly, NYSERDA has also identified that an additional 50 MW of incremental demand reduction can be attributable to existing CHP initiatives expected to be in service by the In-Service Deadline. These projects are already approved and funded under existing CHP avenues in the SBC and Technology and Market Development programs.

Together, Con Edison, NYPA, and NYSERDA have identified these 88 MW of demand reductions as already underway, but not previously reflected in the NYISO's 2012 RNA and may serve to mitigate the reliability need.

conEdison
a conEdison, inc. company

Neil H. Butterklee
Assistant General Counsel

May 20, 2013

VIA E-MAIL
Honorable Jeffrey C. Cohen
Acting Secretary
State of New York
Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re: Case 12-E-0503 – Con Edison Filing of Supplemental Information Regarding its Ramapo to Rock Tavern Project

Dear Acting Secretary Cohen:

On February 1, 2013, in response to a November 30, 2012 order from the Public Service Commission ("Commission") in this proceeding, Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") and the New York Power Authority ("NYPA") filed their Indian Point Contingency Plan ("Plan"), which included a proposal to build three Transmission Owner Transmission Solutions ("TOTS") as well as a plan for NYPA to issue a request for proposals ("RFP") for third party transmission and generation solutions. The Plan contained significant details regarding the three TOTS. In the Commission's March 15, 2013 Order in this proceeding (the "March 15th Order"), the Commission required Con Edison and NYPA to supplement the description of their TOTS with additional information so that the level of information submitted by Con Edison and NYPA to the Commission was comparable to the level of information requested from third party respondents to the NYPA RPF. Accordingly, Con Edison hereby files its supplemental information with respect to the second Ramapo to Rock Tavern ("RRT") 345 kV line project.

As indicated in the Plan and in the accompanying materials, the RRT project is a new resource that interconnects within New York Independent System Operator ("NYISO") load zone G and can be in service by June 2016. The RRT project meets the requirements necessary to be a solution for the retirement of the Indian Point Energy Center ("IPEC"). In addition, this

Consolidated Edison Company of New York, Inc.
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project provides significant additional benefits beyond transmitting replacement energy in the event that the IPEC retires.

Consistent with the requirements of the March 15^{th} Order (p.18), the project costs described in this filing represent a good faith preliminary engineering estimate for the project. That being said, it is possible that the project costs may change as project details are further defined.

Please feel free to contact me if you have any additional questions.

Very truly yours,

/s/ Neil H. Butterklee

Consolidated Edison Company of New York, Inc.

Additional Information on Transmission Owner Transmission Solution for Indian Point Contingency Plan:

<u>Second Ramapo to Rock Tavern 345kV Line Project</u>

May 20, 2013

Contents

Exhibits

8.2 Executive Summary

As shown herein, the New York State Public Service Commission ("Commission") should select Consolidated Edison Company of New York, Inc.'s ("Con Edison" or the "Company") Second Ramapo to Rock Tavern ("RRT") 345 kV line project as one of the solutions in this proceeding for the following reasons:

1. The project can be delivered by the June 2016 deadline and has a clear head start because it has its transmission siting approval and will be built along existing rights–of-way ("ROW"), using existing transmission towers;
2. The project addresses the needs that would exist if the Indian Point Energy Center ("IPEC") were to retire and provides significant benefits throughout the State if the IPEC does not retire;
3. Its estimated costs are reasonable; and
4. The project addresses the numerous public policy needs specified in the Governor's *New York Energy Highway Blueprint* ("Blueprint").[1]

On February 1, 2013, in response to a November 30, 2012 order from the Commission in this proceeding, Con Edison and the New York Power Authority ("NYPA") filed an Indian Point Contingency Plan ("Plan"), which included a proposal to build three Transmission Owner Transmission Solutions ("TOTS") as well as a plan for NYPA to issue a request for proposals ("RFP") for third party transmission and generation solutions. One of the TOTS is Con Edison's RRT project.

The RRT project will establish a second 345kV line from Con Edison's Ramapo 345kV substation to Central Hudson Gas and Electric Corporation's ("CH") Rock Tavern 345kV substation. The project will increase the import capability into Southeastern New York ("SENY"), including New York City, during normal and emergency conditions and will provide a partial solution for system reliability should the IPEC retire. The project will be located in Orange and Rockland Counties in New York along the existing ROW of the existing Con Edison 345kV Feeder 77 (Ramapo to Rock Tavern) and using existing transmission towers. The transmission line terminals are located in New York Independent System Operator ("NYISO") zone G. In addition to Con Edison, this project involves work that will be performed by Orange & Rockland Utilities ("O&R") and CH; as such, the Company has been and will be actively coordinating this effort with both O&R and CH.

[1] A copy of the Blueprint can be found at: http://www.nyenergyhighway.com/PDFs/Blueprint/EHBPPT/.

As indicated in the Plan and in the accompanying materials, the RRT project is a new resource that can be in service by June 2016. A significant part of the Company's ability to deliver the RRT project within the specified timeframe is due to the fact that the RRT project already has its transmission siting approval and a completed and approved NYISO System Impact Study ("SIS") and will utilize the existing ROW and transmission towers along the existing transmission route from the Ramapo to the Rock Tavern 345kV substations. No additional land rights are required to construct the substation upgrades at either the Ramapo substation or the Rock Tavern substation in order to connect the new 345kV line.

The current good faith cost estimate for the RRT Project is $123.1 million. While this project is being submitted by Con Edison, it is anticipated that the RRT project will be owned by the New York Transmission Company, LLC ("NY Transco") and will be one of several Federal Energy Regulatory Commission ("FERC") regulated transmission projects owned by NY Transco. As such, the rates for this project will be based on a cost of service rate and, consistent with the requirements of the March 15th Order, will not be based on a fixed price nor will it be a merchant transmission facility. As the Commission recognized in its March 15th Order, "[w]e understand the TOTS cost estimates to be good faith estimates, rather than 'not to exceed' values."[2] While the Commission directed Staff to "evaluate TO and RFP projects on as comparable a basis as possible, it is neither necessary nor appropriate to provide identical cost recovery provisions for each."[3] It is anticipated that once it is in service, the RRT facility will be under the operational control of the NYISO and its rates included in the NYISO's Open Access Transmission Tariff ("OATT").

Along with the other transmission projects proposed by the NY Transco in PSC Case No. 12-T-0502, the RRT Project is being proposed in order to accomplish the goals and objectives of the Commission's November 30, 2012 *Order Instituting Proceeding* ("AC Order") in Case 12-T-0502,[4] as well as its November 30, 2012 *Order Instituting Proceeding And Soliciting Indian Point Contingency Plan* ("IP Order"), in Case 12-E-0503.[5] In the AC Order, the Commission sought transmission projects that increase transfer capability across the Central East and Upstate New York ("UPNY-SENY") interfaces.[6] In the IP Order, the Commission sought solutions that could

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[2] March 15 Order, p.18.
[3] *Id.*
[4] Case 12-T-0502, *Proceeding on Motion to Examine Alternating Current Transmission Upgrades*.
[5] Case 12-E-0503, *Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans*.
[6] AC Order, p. 2.

address the need that would result if the IPEC were to retire. Both of these orders seek transmission solutions to meet the objectives of the Blueprint. Specifically, the state-wide benefits associated with upgrades to an interconnected transmission system were recognized in the Blueprint, which stated that:

> Ensuring the efficient transmission of power by reducing bottlenecks and developing advanced smart technologies improves overall electric system operation and optimizes the use of existing assets in New York by allowing lower-cost and cleaner power to reach consumers. Investments in the transmission and distribution systems can reduce customer costs over the long-term, improve safety and reliability, and protect the environment while immediately creating jobs and economic development.[7]

The Federal Courts have also found that "[w]hen a system is integrated, any system enhancements are presumed to benefit the entire system." *W. Mass Electric Co. v. FERC*, 165 F. 3d 922, 927 (D.C. Cir. 1999). The RRT project will clearly enhance the state-wide interconnected transmission grid. As described in this submission as well as in the Plan and in the NY Transco's January 25, 2013 filing in Case 12-T-0502, this project will significantly reduce constraints over key transmission interfaces, enhance the long term reliability of the state-wide interconnected transmission grid and provide the additional public policy benefits specified in the Blueprint. Among the public policy goals that the RRT project will contribute to is an increase in economic development within New York State, including increased employment and increases in local tax revenues. The RRT project will also increase the transfer capability into the NYISO's proposed Lower Hudson Valley ("LHV") new capacity zone ("NCZ"), thereby helping to create a convergence in capacity prices between the LHV NCZ and the rest-of-state capacity prices.

The RRT project is a "no regrets" solution to the retirement of the IPEC, meaning that the RRT line makes sense from a public policy point of view even if the IPEC were not to retire. The RRT project does not degrade the New York Transmission System. Pursuant to the approved SIS, the RRT project substantially increases the transfer capability of the independent UPNY/ConEd interface by 1,425 MW (or by 26%) for the normal transfer limits and 2,780 (or by 34%) increase in the Emergency transfer limit. In addition, the RRT Project also increases the transfer capability of the independent UPNY-SENY interface (by 120 MW under normal conditions and by 135 MW under emergency conditions) and of the independent Total East

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[7] Blueprint, p. 10.

Interface (by 60 MW under normal conditions and by 65 MW under emergency conditions). **[Redacted]**.

Accordingly, the RRT project will provide benefits beyond its ability to replace some of the energy and capacity should the IPEC retire. It is clear that the RRT project will provide significant public policy benefits throughout New York State.

8.3 Description of Project

The Project will establish a second 345kV transmission line from the Con Edison Ramapo 345kV substation to the CH Rock Tavern 345kV substation. The project will increase the import capability into SENY, including New York City, during normal and emergency conditions and will provide a partial solution for system reliability should IPEC retire. The project will be located in Orange and Rockland Counties in New York along the existing ROW of the existing Con Edison 345kV Feeder 77 (Ramapo to Rock Tavern), using existing transmission towers; as such, the project is expected to have minimal environmental impact. An environmental review will be conducted through the Environmental Management and Construction Plan ("EM&CP") process as discussed in more detail in this document. The transmission line terminals are located in NYISO zone G.

CH's Rock Tavern 345kV substation will be connected to Con Edison's Ramapo 345kV substation by performing three concurrent system upgrades. The first upgrade would convert O&R's Feeder 28 (Ramapo 138kV substation to Sugarloaf 138kV substation) from its current operating voltage of 138kV to 345kV by reconnecting Feeder 28 at the Ramapo 345kV substation.[8] The second upgrade would be to create a Sugarloaf 345kV substation and add a 345 / 138kV step-down transformer between the Sugarloaf 345kV and 138kV substations. The third upgrade would be to install a 345kV line between Rock Tavern and the Sugarloaf 345kV substation utilizing bundled 1590 ACSR (2 x 1590 ACSR) conductor. A one-line diagram of the RRT project is included in Exhibit A.

The impact of the RRT project towards reducing N-1/-1 deficiency post Indian Point shutdown is about 100 MW. This impact is based on an application of the NYC Reliability Criteria. In general, transmission projects, such as RRT, will have an interaction with other transmission or generation projects that can be either positive or negative (*i.e.*, the stated

[8] The Feeder 28 project is currently under development with O&R, and is expected to be in service in spring 2014. Please refer to Exhibit A for a one-line description of how these two projects will likely be coordinated.

impact may increase or may decrease). Therefore, it is critical that when a comprehensive portfolio analysis is conducted the impact of this project be re-calculated. For example, due to these synergistic effects, when combined with NYPA's Marcy South Series Compensation Project ("MSSC"), the two projects would provide approximately 480 MW towards reducing N-1/-1 deficiency post IPEC shutdown.

8.4 Proposer Experience

Con Edison and O&R are regulated public utilities that are subsidiaries of Consolidated Edison, Inc. ("CEI"), a holding company and a New York Stock Exchange company. In 2012, CEI had $41.2 billion in assets and $12.2 billion in revenues (please see CEI's 2012 annual report). Con Edison serves a 660 square mile area with a population of approximately ten million people. In that area, Con Edison serves approximately 3.3 million electric customers, 1.1 million gas customers, and 1,700 steam customers. Con Edison provides electric service in New York City and most of Westchester County, gas service in parts of New York City and steam service within the borough of Manhattan. Con Edison has approximately 1,180 circuit miles of transmission, including 438 circuit miles of overhead and 742 circuit miles of underground transmission.[9] Con Edison was incorporated in New York State in 1884 and its corporate predecessor, the New York Gas Light Company was founded in 1823.

O&R and its utility subsidiaries, Rockland Electric Company and Pike County Light & Power Company, operate in Orange, Rockland and part of Sullivan counties in New York State and in parts of Pennsylvania and New Jersey, and serve a 1,350 square mile area. O&R provides electric service to approximately 300,000 customers and gas service to approximately 100,000 customers in southeastern New York and in adjacent areas of northern New Jersey and northeastern Pennsylvania. O&R has approximately 558 circuit miles of transmission.

Con Edison is a voting member and O&R is a non-voting affiliated member of the Transmission Owners sector of the NYISO. As transmission owners in New York, Con Edison and O&R helped to create the NYISO and its markets. As the utility responsible for providing electric, gas and steam service to the New York metropolitan area, Con Edison has developed numerous projects over the last ten years, all focused on providing safe, reliable and efficient service to its customers. Recently, Con Edison constructed and put into service the M29

[9] A list of Con Edison's and O&R's transmission and generation facilities can be found in the *2013 Load and Capacity Data, A Report by the New York Independent System Operator "Gold Book,"* which is located at: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2013_GoldBook.pdf.

transmission line. Both Con Edison and O&R have extensive environmental permitting experience gained through projects like the M29 transmission line and the Feeder 28 project currently underway.

With respect to project management, work on the RRT project will initially be managed by Con Edison engineers and project management professionals. Most of the work will be conducted by outside engineering and construction firms.

8.5 Project Information

Consolidated Edison Company of New York, Inc.
4 Irving Place
New York, New York 10003
Attn: Stuart Nachmias
Vice President, Energy Policy and Regulatory Affairs
Tel: 212-460-2580
Email: nachmiass@coned.com

Attn: Neil H. Butterklee, Esq.
Assistant General Counsel
Tel: 212-460-1089
Email: butterkleen@coned.com

It is anticipated that, while Con Edison will commence development of the RRT project, it will transfer the project, as soon as it is able to do so, to NY Transco, a New York limited liability company proposed to be formed in July 2013 and co-owned by the following entities or their newly formed special purpose affiliates (subject, in the case of the public authorities, to the enactment of legislation enabling their participation): Con Edison/O&R, Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"), New York State Electric & Gas Corporation and Rochester Gas & Electric Corporation (together, "NYSEG/RG&E"), NYPA, Long Island Power Authority ("LIPA"), and CH (collectively, the "NYTOs").

Con Edison's DUNS Number is 006982359.

Development of the project will require work by other utilities: specifically, O&R will perform work to develop and construct a new Sugarloaf 345 kV substation (in the town of Chester, Orange County), which will connect to the existing Sugarloaf 138 kV substation via a 345 kV step-down transformer, and CH will perform incremental physical reinforcements to its

Rock Tavern substation (in the town of New Windsor, Orange County). Con Edison expects to actively coordinate its work with that of O&R and CH.

8.6 Disclosure Statements

Neither Con Edison nor any of its affiliates have, during the past five years, been judged or found by any court or administrative or regulatory body to have defaulted on or failed to comply with any material obligation related to the sale or purchase of power (capacity, energy and/or ancillary services), transmission or natural gas.

Neither Con Edison, nor any of its trustees or "executive officers" (as defined by Rule 3b-7 promulgated under the Securities Exchange Act of 1934, as amended) or affiliates have, during the past five years, been convicted of (a) a felony, or (b) any crime related to the sale or purchase of electric power (capacity, energy and/or ancillary services), transmission or natural gas, conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions, or collusive bidding or other procurement or sale-related irregularities.

8.7 Financial Capacity to Complete and Operate the Proposed Project

The Company has completed the Financial Data Sheet, included as Attachment 5 to the NYPA RFP and attached hereto as Exhibit B, with respect to the project. As discussed further below, the Exhibit assumes that the RRT project will be transferred to NY Transco around spring 2014 and subsequently developed and financed by NY Transco.

Prior to its transfer to NY Transco, Con Edison will finance construction of the RRT Project in the same way that it currently finances its capital needs: by issuing long-term debt in the capital markets. Debt financing at Con Edison must be approved by the Commission via a financing order. Under the Company's current financing order, Con Edison has authorization to issue $3.5 billion of debt through December 2016. In addition, the Company's financing may be limited by the capital structure approved by the Commission. The Company currently has an approved equity ratio of 48%. Funding for the RRT project will take into consideration the Company's approved equity ratio.

Information concerning Con Edison's financial condition may be obtained upon review of the Company's audited financial statements, which are available publicly and accessible on the Company's website, at www.conedison.com or on the Securities and Exchange Commission's website, at www.sec.gov/edgar. The Company's unsecured debt is rated A3, A- and A-, respectively, by Moody's Investor Service, Inc. ("Moody's), Standard & Poor's

Corporation ("S&P") and Fitch Ratings, Inc. ("Fitch"). CEI's long-term credit rating is Baa1, BBB+ and BBB+, respectively, by Moody's, S&P and Fitch. The commercial paper of both the Company and CEI is rated P-2, A-2 and F-2, respectively, by Moody's, S&P and Fitch. Securities ratings assigned by rating organizations are expressions of opinion and are not recommendations to buy, sell or hold securities, and may be revised or withdrawn at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating.

Accordingly, Con Edison expects to transfer the RRT project to NY Transco as promptly as possible upon the commencement of its operations (which is anticipated to occur following (i) enactment of necessary legislative changes and procurement of approvals, if applicable, of the Comptroller and/or Attorney General of the State of New York with respect to NYPA and LIPA's participation, as well as (ii) receipt of approvals by FERC of a transmission formula rate schedule and incentives, and (iii) implementation of cost allocation and cost recovery mechanisms through the NYISO's tariff, all of which are expected by the middle of 2014). It is expected that NY Transco will be able to obtain investment grade construction debt financing once its rate is approved by FERC, and that NY Transco will also receive certain FERC incentives, including construction work in progress, that will reduce construction risk. Equity support will be provided to the Transco by the NYTO's investing affiliates during construction and, to the extent necessary, thereafter to support continued operations. It is anticipated that the NY Transco will make its formula rate filing at FERC during the summer of this year. As such, it is premature to specify the exact debt / equity ratio that will be approved by FERC for this project. However, for informational purposes a 50/50 debt to equity capital structure is assumed in Exhibit B.

8.8 Environmental Benefits of Project

The project's primary objectives are to meet the public policy goals stated in the Blueprint including: reducing congestion over the UPNY/SENY interface, providing economic benefits to local communities, encouraging renewables, enhancing the long-term reliability of the bulk power system and planning for a possible IPEC retirement. By increasing transfer capability on constrained interfaces into the Southeast New York area, the project will allow high load density areas, such as New York City and parts of the Lower Hudson Valley greater access to generation resources in upstate New York.

Because the RRT project will be located on an existing ROW using existing transmission towers, no additional vegetation management work would be needed for this project. As such, the project minimizes the environmental impacts on neighboring communities.

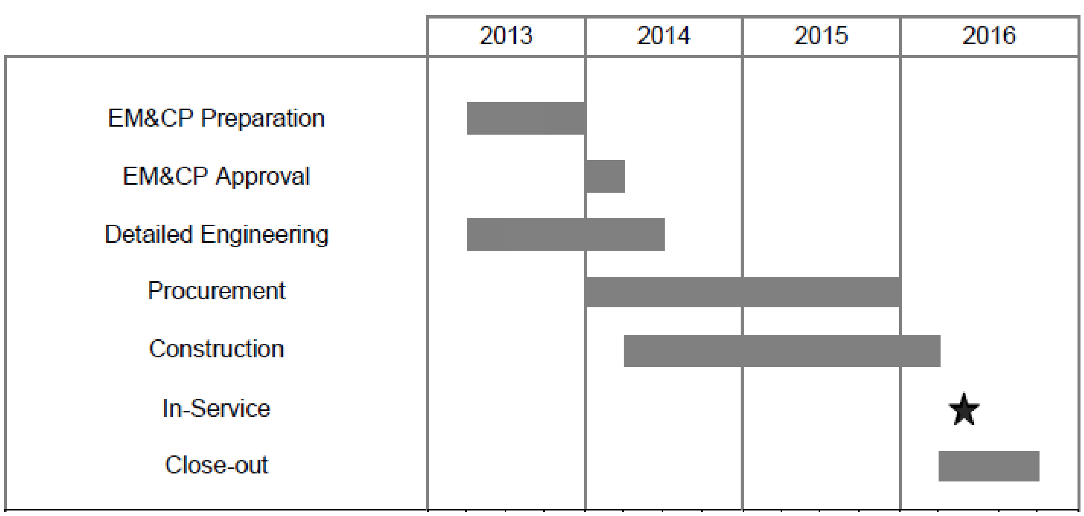
The RRT project is not expected to reduce emissions in the near term when added to the current New York State resource mix, which would remain largely unchanged by year 2016 when the project comes into service. However, the project will provide appreciable environmental benefits to New York State in the future by enabling renewable energy deliverability from favorable wind sites in upstate New York into high load density areas downstate, thereby facilitating the development and integration of additional wind generation in New York State and helping realize a cleaner resource mix.

The New York State Transmission Assessment and Reliability Study ("STARS"), which issued its Phase II technical report on April 30, 2012, envisioned a future resource mix that incorporates 6,000 MW of wind capacity in upstate New York by the year 2030. The STARS report evaluated a portfolio of transmission upgrades intended to improve system reliability and deliverability, and ultimately reduce congestion costs. The RRT project was among the projects studied. The STARS report estimated that adding the RRT project to other upgrades in the portfolio resulted in notable incremental benefits, one of which is a reduction of approximately $2 million in emission costs, or the equivalent of approximately 40,000 tons in CO_2 emissions, over the study year.

8.9 Proposed Resource(s) Development Plans and Schedule

The following represents the current high-level schedule and work plan for the development of the RRT Project.

MS Project Gant Chart



Proposed In-Service Date May 2016

No contracts with NYPA are necessary to achieve this in-service date.

Proposed Date for PSC and FERC Orders to Achieve In-Service Date

The following represent the proposed dates for key PSC and FERC approvals that are necessary to achieve the June 2016 in-service date.

1. PSC selection in Case 12-E-0503 – September 2013
2. PSC approval of EM&CP and amendment of existing Article VII – 1st Quarter 2014
3. FERC approval of NY Transco formula rate – mid 2014
4. FERC approval of NY Transco incentives – mid 2014
5. FERC approval of cost allocation for NY Transco – mid 2014
6. PSC approval of Section 70 asset transfer filing – 4th Quarter 2014

Timeline for Award of Engineering, Procurement, Construction ("EPC") Contract

The EPC Contract will be performed in phases. The first phase, engineering, will be awarded by the third quarter of 2013. It is anticipated that CH will be responsible for the work at the Rock Tavern substation.

Lead Times for Major Equipment

- The following are the lead times for major equipment:
  - 1590 ACSR Conductor = **[Redacted]**
  - 345 / 138kV Transformer = **[Redacted]**
  - 345kV Open Air Bus = **[Redacted]**
  - 345kV Breakers = **[Redacted]**

Plans for Construction and Operation

The construction work is expected to be performed by an EPC contractor. Once the project is operational, Con Edison, O&R and CH may perform operation and maintenance ("O&M") services for the NY Transco with respect to the Project in accordance with the terms of an O&M Agreement between the parties and consistent with the affiliate rules of the Commission and FERC. Similar to other transmission assets in the State, the line will be under operational control of the NYISO.

Community Outreach Plans

The second RRT project is in the same transmission ROW and on the same towers as the recently approved O&R Feeder 28 project. The outreach plan for the RRT project will follow a similar approach to what was done for Feeder 28. For Feeder 28, O&R met with elected officials in each of the municipalities to brief them on the project, and communicated directly with adjacent property owners to notify them of the project and the associated vegetation management. Prior to the start of the RRT project, O&R will meet with elected officials in each of the communities that the 345kV line will pass through to notify them of the project. O&R will provide each property owner adjacent to the transmission ROW with a written letter/fact sheet explaining the project. During the project, updates will be provided to property owners adjacent to the line as necessary. O&R will provide contact information for individual concerns to be raised and coordinate with the affected party or parties to resolve the issues.

Equity and Debt Financing Plans

Please see description of financing plans in section 8.7.

Contractor Experience

This information is not yet available, as the EPC and other contractors have not yet been procured for this project. It is expected that contractors with appropriate experience and expertise will be hired at a reasonable cost.

Community Benefits

Please see the response to section 8.14 dealing with the RRT project's economic development benefits.

Taxes and/or PILOT agreements

The RRT project will run through several distinct municipalities and over both public and private lands. Because transmission lines are real property under the New York State Real Property Tax Law, the Company expects that local property taxes will be levied with respect to this facility by each municipality in which the line runs over private lands and to New York State where the line runs over public land. Although property taxes throughout the state are generally based on the property's reproduction cost new less depreciation, rates vary significantly from jurisdiction to jurisdiction as well as from year to year, and therefore cannot be predicted with certainty. A generic assumption was used for estimating property taxes in the financial data sheet included in Exhibit B.

Site Control Status and Plans for Site Control

The following represents the site control plan for the RRT project:

- The project will affect three substations, Ramapo (owned by Con Edison), Sugarloaf (owned by O&R), and Rock Tavern (owned by CH).
- The existing easement ROW to be used for the installation of Feeder 76 is owned by Con Edison.
- Access roads to ROW discourage public entry.
- Any parties requesting access / visitation to Con Edison and O&R's substations and ROWs shall have escorted access with Con Edison or O&R employees, at a time acceptable to Con Edison and/or O&R.
- Con Edison will request access to CH's Rock Tavern substation as needed throughout the project.
- During construction, the project team will follow the Storm Water Pollution Prevention Plan ("SWPPP") document along with other permit requirements detailed in Section 8.10 including appropriate site control plans, *i.e.*, safety, security guards, additional gate/barriers, and other related items.

Operations Plan

Con Edison estimates that some incremental O&M will be required once the RRT line is in service. Preliminary annual cost estimates of O&M are included in Exhibit B. The following is a list of the expected O&M activities associated with Feeder 76 once the line is in service, most of which will be coordinated with the O&M for the existing Feeder 77 along the same ROW, and using existing towers:

- Semi-annual line patrol
- Bi-monthly aerial patrol
- Three year vegetation management cycle
- Ground testing every five years
- Climbing inspection every five years
- Tower painting every 15 years
- Stray voltage testing 20% per year
- Emergency patrols as needed
- ROW maintenance as needed
- Security

NYISO Interconnection Status

The RRT project was submitted to the NYISO interconnection process and has queue position 368. An SIS was completed and approved by the NYISO Operating Committee on August 16, 2012. No further action related to the NYISO interconnection process is required. A one-line of the proposed interconnection points is included in Exhibit A.

Environmental Justice Issues

Con Edison will conduct an analysis of potential environmental justice concerns for the Indian Point Contingency projects in accordance with NYSDEC Commissioner Policy CP-29, *Environmental Justice and Permitting.* The analysis will identify any Potential Environmental Justice Areas to be affected, describe the existing environmental burden on the Potential Environmental Justice Area and evaluate the potential burden of any significant adverse environmental impact on the area.

EPC Cancellation Provisions

Con Edison intends to include in any contract into which it enters in relation to the development and construction of the Project a right to terminate the contract at Con Edison's election for any reason. Upon such termination, the Company intends to require the contractor to stop performing all work and to cancel as quickly as possible all orders placed by it with subcontractors and suppliers, and to use reasonable efforts to manage cancellation charges and other costs and expenses associated with termination of work. The Company will also seek to enter into fixed price contracts, with payment contingent upon the achievement of certain milestones, to the greatest extent possible. While Con Edison intends to seek such terms, there can be no assurance that the Company will be successful in achieving them. In this regard, the Company notes that much of the equipment the Project requires will be highly customized; as a consequence, the Company does not expect to be able to cancel such orders (or that its contractor will be able to cancel such orders) once they are placed. The Company would expect that any proposer seeking to develop and construct transmission projects would be subject similar constraints.

8.10 Environmental Review

The environmental permitting plans for the Indian Point Contingency Projects were presented in earlier Con Edison PSC filings, and are incorporated herein by reference. Con Edison is now proceeding with procurement of environmental permitting vendors, pursuant to the PSC Order issued on April 19, 2013 directing Con Edison to begin development of these projects (Case No. 12-E-0503).

Permitting Plan:

Con Edison received an Article VII Certificate in 1972 that authorized the construction of the Ramapo to Rock Tavern transmission route with towers that could accommodate two 345kV circuits, although only one circuit was needed at that time. The Commission Order granting the Certificate allowed Con Edison to install the additional circuit with prior notice to the Commission. In 2010, Con Edison and O&R jointly petitioned the Commission to allow O&R to install proposed Feeder 28, a second circuit on the existing towers along the transmission route from Ramapo substation to Sugarloaf substation. The Commission allowed O&R to install proposed Feeder 28 under the original Article VII Certificate issued in 1972. However, given the passage of time since the Certificate was granted, the Commission requested that O&R submit an updated EM&CP presenting an assessment of potential environmental impacts associated with the installation of the proposed additional circuit. A Commission Order transferring a portion of the Article VII Certificate to O&R for installation of Feeder 28 from Ramapo to Sugarloaf, and approving the updated EM&CP, was issued on January 24, 2011 (Case 10-T-0283).

Based on the experience with Feeder 28, Con Edison expects that the only key permitting/approval requirements for the second Ramapo to Rock Tavern transmission line, also called Feeder 76, is Commission approval of updated EM&CP for the project and an amendment to the existing Article VII Certificate transferred to O&R for Feeder 28 to provide for the installation of a 345/138kV step-down transformer from Feeder 76 to Sugarloaf. It is envisioned that Con Edison and O&R would jointly file the EM&CP and the Article VII amendment as both approvals would be required for the Feeder 76 project. The EM&CP would address the Sugarloaf substation to Rock Tavern substation section of the existing ROW, including any incremental physical reinforcements needed to bring the existing transmission towers to current standards. The EM&CP would also address the incremental additional equipment required at the Ramapo and Rock Tavern substations, and would be equivalent in content and level of detail to the Feeder 28 EM&CP, which was approved by the Commission in January 2011. The Article VII amendment, similar to an EM&CP, would address the environmental impact of the proposed Sugarloaf 345kV substation.

The Feeder 76 EM&CP and Article VII amendment would together present an assessment of potential environmental impacts associated with the installation of the proposed additional circuit on the existing towers, and with the construction and operation of the proposed Sugarloaf 345kV substation and the incremental additional equipment at Ramapo and Rock Tavern substations. The EM&CP and Article VII amendment would identify the governing federal, state and local permitting and regulatory requirements, and evaluate the Feeder 76 project components against the substance of those requirements. This effort would include evaluation of Feeder 76 predicted magnetic field levels against the Commission's interim 200 mG standard, and consultation with other state and local agencies on matters within their jurisdiction (*e.g.*, with NYSDEC regarding protection of State endangered/threatened species). A Request for Proposal has been issued by Con Edison to procure an environmental firm to perform the EM&CP study.

The following sets forth a preliminary list of major federal, state and local permits/approvals that are expected to be filed separately from the EM&CP and Article VII amendment:

1) Federal permits/approvals governing Feeder 76 project activities in any Federally-regulated wetlands and water bodies:

   The existence and extent of any Federally-regulated wetlands or water bodies would be identified during preparation of the Feeder 76 EM&CP. Feeder 76 installation activities affecting any Federally-regulated wetlands and water bodies would likely be permitted under the Clean Water Act Section 404 Nationwide Permit No. 12 ("NWP 12"), which was developed to cover land clearing and similar activities associated with installation of utility line crossings of wetlands and water bodies. NWP 12 provides authorization for such activities provided the cleared area is kept to the minimum necessary and preconstruction contours are maintained. The eligibility of Feeder 76 installation activities for NWP 12 would be confirmed during preparation of the EM&CP, and the required Pre-Construction Notification ("PCN") prepared and filed with the U.S. Army Corps of Engineers.

2) Federal requirements governing endangered/threatened species and archeological/cultural resources, which may require that protective measures be employed during installation of Feeder 76:

   During preparation of the EM&CP, the potential for Feeder 76 installation activities to affect such resources would be identified, any necessary Federal agency consultation would be performed, and any necessary protective measures would be developed.

3) State permits/approvals governing Feeder 76 project activities in any State-regulated wetlands and water bodies:

   The existence and extent of any State-regulated wetlands (defined differently than Federally-regulated wetlands) and State-regulated water bodies would be identified during preparation of the Feeder 76 EM&CP. NY Transco would likely follow the process Con Edison and O&R recently undertook for installation activities affecting State-regulated wetlands and water bodies with respect to Feeder 28 (that is, O&R was given authorization by NYSDEC to conduct feeder installation activities in accordance with a NYSDEC General Permit issued to O&R under Environmental Conservation Law Article 15 – Protection of Waters and Article 24 – Freshwater Wetlands). The eligibility of Feeder 76 activities for coverage under Con Edison/ O&R's corresponding NYSDEC General Permit would be identified during preparation of the EM&CP, and the required notification package submitted to the NYSDEC.

4) Coverage under NYSDEC SPDES Construction Storm Water General Permit:

The Feeder 76 EM&CP preparation effort would include a State Pollutant Discharge Elimination System (SPDES) Construction Storm Water Pollution Prevention Plan (SWPPP) as a component of the EM&CP, and a Notice of Intent for filing by NY Transco with NYSDEC.

5) State and Local Transportation and Utility Crossing permits/approvals:

The Feeder 76 installation activities have the potential to impact roads, highways, railroads and other existing utilities. The EM&CP preparation process would identify each crossing affected and outline construction practices ensuring that vehicular, pedestrian or rail traffic is not adversely impacted. The appropriate state and local officials would be contacted and required permits for crossing and construction access would be obtained. For New York State highways this would require preparation and submission of NYSDOT Highway Work Permit applications, and Maintenance & Protection of Traffic Plans.

8.11 Pricing – Transmission Project

Project Cost Estimate

[Redacted]

Pricing Assumptions

[Redacted]

Transmission Rates

[Redacted]

Supporting Financial Exhibits

[Redacted]

8.13 Halting Costs

Due to the unique nature of transmission projects, Con Edison will need to purchase equipment that may not be usable for any other project. As such, the halting mechanisms reflect the fact that once equipment is ordered, Con Edison and NYPA must be able to recover 100% of the cost of such equipment, less any reductions available from cancellation provision in the procurement contract and realized salvage value. The halting mechanism also recognizes that in order to meet the In-Service Deadline, Con Edison has started the procurement process for a firm to perform the EM&CP, as well as preliminary engineering work for the project in April 2013 and will start equipment procurement activities as early as the third quarter of 2013. Thus, the halting mechanism must provide for the full recovery of costs incurred, as well as any contractual cancellation costs associated with such activities. It should also be noted that equipment procurement, engineering, and some construction activities will start even though not all of the required regulatory permits (environmental or community) will have been obtained as of this point in the project development schedule.

Recognizing the potential cost impacts to customers for the RRT Project, Con Edison can state the estimated costs that it will incur for the RRT Project at particular key points in time. Importantly, these estimates are based on conceptual project scopes and represent an order of magnitude reference for future project costs. As preliminary engineering and project tasks proceed, additional detail and certainty will support updated cost estimates. With respect to the RRT project, the estimated costs of halting the project at the key points in time are shown below:

Ramapo – Rock Tavern Line	Date Halted	Estimated Partial At Risk Cost*
(Project Total: $123,100,000)	9/30/2013	**[Redacted]**
	3/31/2014	**[Redacted]**

	12/31/2014	**[Redacted]**
* The "Estimated Partial At Risk Cost" includes only an estimate of the committed dollars and do NOT include any cancellation charges that would be imposed by the contractors and equipment suppliers. The "Estimated Partial At Risk Costs" will be adjusted at the time of halting to include these costs. These costs are based on a 2016 in-service date estimate.		

8.13 Cancellation Clauses

See response to item 8.9.

8.14 Other Requirements

List of Required Easements and ROW Requirements

The project will utilize the existing ROW and transmission towers along the existing transmission route from the Ramapo to the Rock Tavern 345kV substations. At this time, no additional land rights are required to construct the substation upgrades at either the Ramapo or the Rock Tavern substations in order to connect the new 345kV line. Siting of the property for the Sugarloaf 345kV substation has not been completed, but it is anticipated this substation will utilize existing property owned by O&R in the vicinity. After the completion of the environmental studies, Con Edison will be able to better define if there is a need for any additional easements and properties.

Economic Development Benefits

Along with the other transmission projects proposed by the NY Transco in PSC Case No. 12-T-0502, this project is being proposed in order to accomplish the goals and objectives of the AC Order and the IP Order. In the AC Order, the Commission sought transmission projects that increase transfer capability through the Central East and UPNY/SENY interfaces.[10] In the IP Order, the Commission sought solutions that could address the need that would result if the IPEC were to retire. Both of these orders seek transmission solutions to meet the objectives of the Blueprint. As described in this submission as well as in the Plan and in the NY Transco

[10] AC Order, p. 2.

January 25, 2013 filing in Case 12-T-0502, this project will significantly reduce constraints over key transmission interfaces and provide the public policy benefits specified in the Blueprint.

Among the public policy goals that the RRT project will contribute to is an increase in economic development within New York State. Specifically, the RRT project is estimated to cost approximately $123 million in 2016 dollars. As a result of this investment, the New York State economy will reap significant economic development benefits in the form of increased employment and increases in local tax revenues.

Based on analyses performed by the Working Group for Investment in Reliable and Economic Electric Systems (the "WIRES" group) in conjunction with the Brattle Group, this $123 million of investment will support an estimated 500 direct full time equivalent ("FTE") jobs and nearly 1,600 total FTE jobs.[11] The directly supported jobs represent those related to domestic construction, engineering and transmission component manufacturing. Indirect job stimulation represents suppliers to the construction, engineering and equipment manufacturing sectors as well as jobs created in the service industries (*i.e.*, food and clothing) supporting those directly and indirectly employed. The RRT project is also estimated to increase annual local tax revenue by approximately $2.5 to $3.5 million.[12] The majority of this increased revenue will flow to the upstate regions of New York.

Statement with Respect to NYPA Appendixes and Bid Documents

It is intended that cost recovery for the RRT project will be accomplished through regulated transmission rates and not via a contract with NYPA. As such, the provisions set forth on the NYPA appendixes and the bid documents are inapplicable to the RRT project. That being said, the Company is providing the attached documents to demonstrate its commitment to equal opportunity and diversity and to aid the Commission in reaching its decision regarding which projects should be selected in this proceeding. This statement and the inclusion of these

[11] The direct and total job numbers are based on generic information included in the May 2011 report entitled *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, which was developed by the WIRES group in conjunction with the Brattle Group. The report concluded that every $1.0 billion of transmission investment supports 4,250 direct FTE years of employment and 13,000 total FTE equivalent years of employment. This report can be found at the following link: http://www.wiresgroup.com/images/Brattle-WIRES_Jobs_Study_May2011.pdf.

[12] The estimated annual local tax revenue associated with these projects is based on a factor of approximately 2 -3% of project capital costs, which is consistent with the NY Transco estimate provided in Case 12-T-0502.

documents satisfy the requirements of the Commission's March 15th Order in Case 12-E-0503, which required that Con Edison provide information that is comparable and at the same level as that sought from official responders to the NYPA RFP.

Accordingly, Con Edison has attached the following documents to this response in Exhibit E:

1. Policy on Sexual Harassment
2. Policy on Equal Employment Opportunity
3. Employment of Individuals with Disabilities, Disabled Veterans, and Other Qualified Veterans

In addition the Company's annual 2012 diversity report can be found at the following link: 2012 Diversity Annual Report

8.15 Compliance Statement

It is anticipated that the Project will comply with applicable laws and regulations.

8.16 Project Benefit / "No Regrets" Analysis

In addition to the economic development benefits described above, the RRT project provides public policy benefits to New York State even if the IPEC does not retire. Summarized below is a "no regrets" analysis of the economic benefits this project produces in 2016 for all of the NYCA.

The RRT project substantially increases the transfer capability of the independent UPNY/ConEd interface by 1,425 MW (or by 26%) for the Normal transfer limits and 2,780 (or by 34%) increase in the Emergency transfer limit. In addition the RRT project also increases the transfer capability of the independent UPNY-SENY interface (by 120 MW under normal conditions and by 135 MW under emergency conditions) and of the independent Total East Interface (by 60 MW under normal conditions and by 65 MW under emergency conditions). **[Redacted]**

Additionally, when coupled with the Marcy South Series Compensation project, the transfer capability is further increased, providing even greater benefit to the State.

[Redacted]

New York Power Authority

And

New York State Electric & Gas Corporation

Submission of Comparable Information

Pursuant to the April 19, 2013 Public Service Commission Order

Case 12-E-0503

Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring Project

May 20, 2013

Table of Contents

Note: Section 8.11.2, Section 8.13, and all Exhibits have been redacted from this version of the submittal due to the confidential nature of the contents.

Executive Summary of Project **(Section 8.2)**

As part of a long-term transmission planning study performed by the New York Power Authority ("NYPA") in 2011, the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring ("MSSC") project was identified as a means to increase power transfer from upstate generators to downstate load in a cost effective manner. The project consists of installing switchable series compensation on the existing Marcy South transmission lines[1] and reconductoring a section of the 345 kV Fraser to Coopers Corners FCC-33 line. MSSC improves power flow over an existing asset by installing a relatively sophisticated technology, switchable series compensation. The switchable series compensation will be controlled by the New York Independent System Operator ("NYISO") and allow the NYISO to vary the power flows across the bulk power transmission system based on system conditions.

After the issuance of the Energy Highway Initiative by Governor Cuomo in his 2012 State of the State address, it became apparent to NYPA and New York State Electric & Gas ("NYSEG") that the MSSC is a project that can reduce the transmission bottleneck in central New York and optimize the use of an existing asset. The Final Report of the System Impact Study ("SIS") for the MSSC project (NYISO-Queue #380) shows a transfer limit increase of 444 MW across the Total East Transmission Interface due to the series compensation. The SIS has been completed, approved by the NYISO's TPAS committee, and is expected to receive final approval by the NYISO Operating Committee ("OC") on May 20, 2013. The series compensation increases power flow from Zone E into Zones F and G.

In addition to the technological advancement, MSSC has environmental and economic benefits. From an environmental perspective, the series capacitors will be installed on existing NYPA and NYSEG property, near existing substations, and will not require any additional Right-of-Way ("ROW"). During operation, the MSSC project will not directly generate any air or water pollution. From the economic viewpoint, the increased power flow of 444 MW at an estimated cost of $76 million equates to a cost of less than $200,000 per MW.

The MSSC project improves the power flow from upstate generation to downstate load in a cost effective manner by increasing the utilization of existing AC transmission assets. The in-service date for the MSSC project is June 1, 2016.

It is respectfully submitted that the MSSC project accomplishes all of the goals of this proceeding. The MSSC project can be in service by June 1, 2016, provides significant benefits at a reasonable cost, addresses reliability needs should Indian Point Energy Center ("IPEC") retire, and facilitates increased capability to more efficiently deliver upstate generation to downstate load.

Description of Project **(Section 8.3)**

The MSSC project is a transmission improvement project that adds switchable series compensation to increase power transfer by reducing series impedance over the existing 345 kV Marcy South lines. Specifically, the project adds 40% compensation to the Marcy-Coopers Corners 345 kV line, 25% compensation to the Edic-Fraser 345 kV line, and 25% compensation to the Fraser-Coopers Corners 345

[1] Marcy South transmission lines are Marcy to Coopers Corners (UCC2-41), Edic to Fraser (EF24-40), and Fraser to Coopers Corners (FCC-33).

KV line through the installation of series capacitors. The project also involves upgrades at Marcy and Fraser 345 KV substations. The project reconductors approximately 21.8 miles of the NYSEG-owned Fraser-Coopers Corners 345 kV line (FCC-33) with a higher thermal-rated conductor installed on existing wooden pole and steel tower structures. The project increases thermal transfer limits across the Total East Interface and the UPNY/SENY Interface and provides a partial solution for system reliability should IPEC retire.

The MSSC project transmission corridor begins at the Marcy substation near Utica, New York and ends at the Coopers Corners substation near Monticello, New York. Both substations are located in Zone E, but the MSSC produces increased power flow into Zones F and G. The MSSC project has minimal environmental and community impacts as the construction will occur in existing ROW, outside of any New York State Department of Environmental Conservation ("NYSDEC")-regulated wetlands, and on NYPA and NYSEG easements.

The Final Report of the SIS of the MSSC project (Queue #380) has been completed, approved by the NYISO's TPAS committee, and is expected to receive final approval by the NYISO OC on May 20, 2013.

The Exhibits to this submission contain the following:

1- A map of the location of the MSSC (Exhibit A).
2- Maps of the Marcy and Fraser substations (Exhibits B and C), respectively.
3- A picture of a sample series capacitor installation (Exhibit D).
4- A picture of a typical FCC-33 wood pole structure (Exhibit E).
5- List of NYPA & NYSEG's generating facilities and transmission lines (Exhibit F).
6- NYPA RFP, Attachment 3 (Exhibit G).
7- NYPA RFP, Attachment 5 (Exhibit H).
8- NYPA RFP, Attachment 7 (Exhibit I).

Proposer Experience **(Section 8.4)**

Created in 1931, NYPA is a public authority and political subdivision of the State which owns and operates 16 generating facilities and about 1400 circuit miles of high voltage transmission lines. A list of NYPA's generating plants and transmission lines is included in Exhibit F. The electricity NYPA generates and purchases is sold to municipally owned utilities and electric cooperatives, as well as to a variety of business, industrial and public customers throughout the State. NYPA is a fiscally independent public corporation that does not receive State funds, tax revenues, or credits.

NYPA has a long and proud history of constructing energy infrastructure in New York State, beginning with the construction of the St. Lawrence-FDR Project and the Niagara Power Project, completed in 1958 and 1961, respectively. These projects, in conjunction with NYPA's Blenheim-Gilboa Project (completed in 1973), provide over 4500 MW of clean hydropower for New York State customers. In the 1970's, NYPA constructed: 1) 230 kV transmission line from the St. Lawrence-FDR Project to Plattsburgh, 2) 345 kV transmission line from Blenheim-Gilboa Project to Leeds and 3) 765 kV line from Massena to Marcy. In the 1980's, NYPA built the Marcy South lines and the Sound Cable Project.

NYPA's most recent experience involving the development, financing, and construction of electric generating plants and/or transmission facilities includes the 500MW Combined Cycle Power Project located in Astoria, New York which became commercially operational in December 2005, and the current construction of the HTP transmission project with a projected in-service date of May 2013. NYPA in conjunction with National Grid financed, licensed and constructed the Tri-Lakes Reliability Project, which was a 69 kV transmission project in the Adirondack Park that went into service in 2009.

NYSEG is a regulated public utility organized under the laws of the State of New York. NYSEG is engaged in the transmission and distribution of electric power and natural gas. NYSEG provides electric service to 878,000 customers in 42 counties in New York State. NYSEG owns 4,583 miles of electric transmission lines, 32,881 miles of electric distribution lines and 444 substations. A list of NYSEG's generating plants and transmission facilities are contained in Exhibit F. NYSEG is a wholly-owned subsidiary of Iberdrola USA, Inc., which in turn is a subsidiary of Iberdrola, S.A. (an international energy company listed on the Madrid Stock Exchange).

NYSEG's most recent experience with the development, finance and construction of transmission includes:

Ithaca Transmission Project-consisting of a new 345 kV/115 kV Clarks Corners Road Substation, rebuilding of the 115 kV transmission line #945 from Etna to Lapeer, and construction of a new 15 mile, 115 kV line #715 from Etna to the new substation.

Corning Valley Project-consisting of a new 230kV/115kV Stoney Ridge Substation, and construction of a 9.6 mile 115 kV transmission line from West Erie Avenue Substation to the Stoney Ridge Substation.

In addition to this major construction work, NYSEG plans to conduct over $41,000,000 of capital work on its extensive transmission system in 2013.

NYPA and NYSEG were both member companies of the New York Power Pool, the predecessor to the NYISO. As such, both companies played a fundamental role in the development and establishment of the NYISO, its markets and associated FERC jurisdictional tariffs. As members of the NYISO, NYPA and NYSEG actively participate in its governance, and are owners of extensive transmission facilities under the operational control of the NYISO.

NYPA and NYSEG have extensive experience obtaining regulatory approvals for the construction and operation of transmission and generating facilities. Major approvals which have been obtained in the past include, but are not limited to, Certificates of Environmental Compatibility and Public Need (Article VII Certificates), Article X Permits, Army Corps of Engineers (ACOE) permits, and 401 Water Quality Certificates.

NYPA and NYSEG have extensive personnel resources to contribute to this project. The primary Project Management team will consist of the following individuals:

NYPA TEAM:

Project Sponsor:	John Suloway	Vice President, Project Development & Licensing
Project Leader:	Mark Malone	Director, Project Development & Licensing

Principal Engineer:	Ben Shperling	Principal Electrical Engineer
Project Management:	Ricardo DaSilva	Electrical Engineer II
EH&S:	Jeff Gerlach	Manager, Environmental Studies & Remediation
Finance:	Tom Davis	VP, Financial Planning & Budgets
Compliance:	Wayne Sipperly	NERC Reliability Compliance Program Manager
Accounting:	Austin Davis	Manager, Plant & Cost Accounting
Law:	Andrew Neuman	Special Counsel
Law:	Glenn D. Haake	Principal Attorney II
Real Estate:	John Wingfield	Geographic Information System Manager

NYSEG Team:

Project Sponsor:	Javier Bonilla	Vice President, Engineering & Capital Delivery
Project Leader:	Ellen Miller	Director, Electric Capital Delivery
Principle Engineer:	Brian Conroy	Director, Electric System Engineering
Project Management:	Joseph Simone	Manager, Electric Capital Delivery
Environmental & Licensing:	Carol Howland	Lead Analyst, EH&S Compliance
Law:	Noelle Kinsch	Deputy General Counsel
Real Estate:	Deborah Drake	Supervisor, Property Management

To supplement in-house resources, NYPA and NYSEG have the contractual arrangements and the financial resources to obtain outside expertise that will contribute to the MSSC project in a professional and responsive manner. NYPA and NYSEG are committed to completing this project by the June 1, 2016 operational date. It is anticipated that the MSSC will be ultimately transferred to the NY Transco[2].

Project Information **(Section 8.5)**

Created in 1931, NYPA is a public authority and political subdivision of the State. NYPA's Dun & Bradstreet number is 07-525-2098

New York Power Authority
123 Main Street
White Plains, New York 10601
Contact Person: Mark Malone
Contact phone: (914) 390-8026
Contact email: mark.malone@nypa.gov

[2] The NY Transco is a New York limited liability company proposed to be formed in or about July 2013 and co-owned by the following entities or their newly formed special purpose affiliates: Consolidated Edison/O & R; Niagara Mohawk Power Corporation, a New York corporation d/b/a National Grid; NYSEG, a New York Corporation, and Rochester Gas & Electric Corporation, a New York Corporation; NYPA, a corporate municipal instrumentality and political subdivision of the State of New York; and the Long Island Power Authority.

Created in 1852, NYSEG is an electric and gas corporation regulated by the New York State Public Service Commission. NYSEG's Dun & Bradstreet number for its Link Drive office is 04-186-6497.

NYSEG
18 Link Drive
Binghamton, New York 13902
Contact Person: Ellen Miller
Contact Phone: (207) 621-3936
Contact email: ellen.miller@cmpco.com

Disclosure Statements (**Section 8.6**)

Upon information and belief, NYPA has no disclosures to make pursuant to the requirements of Section 8.6. Iberdrola USA and its subsidiaries, including NYSEG, are defendants in numerous civil litigation matters in the ordinary course of business. In some of these matters, the allegation or cause of action may be for conversion or fraud. However, none of these litigation matters where the allegation is for fraud or conversion are material.

Financial Capacity to Complete and Operate the Proposed Project (**Section 8.7**)

Financing Plan

NYPA will secure its own portion of financing requirements through its access to the capital markets with a portion of the MSSC project costs expected to be financed through equity (see further discussions below).

NYPA is a New York State Authority and does not have a parent. NYPA has favorable debt / total capitalization (34%) and debt / equity (51%) ratios; days cash on hand (200+); unrestricted cash and investments ($1.4 billion); and credit ratings of AA-/Aa2/AA (S&P, Moody's, Fitch). As such, NYPA has readily available access to the capital markets as well as sufficient equity to finance the MSSC project. It is anticipated that the MSSC project will be transferred to the NY Transco and subsequently developed and financed by the NY Transco.

For the MSSC project, NYPA proposes a capital structure of fifty percent debt, fifty percent equity. The debt would be structured to match the expected useful life of the MSSC project. As noted above, because of NYPA's strong credit rating, it is able to obtain very favorable financing rates.

NYPA currently owns and operates in New York five major generating facilities, four small hydroelectric facilities, and eleven small electric generating units, with a total installed capacity of approximately 6,051 megawatts ("MW"), and a number of transmission lines, including major 765-kV and 345-kV transmission facilities.

Aside from financing Life Extension and Modernization programs at two of its large hydroelectric facilities, NYPA financed and constructed a 500 MW combined cycle generating plant in Astoria, New York which went into commercial operation December 31, 2005. NYPA initially used short-term financing to fund preliminary engineering and start-up construction costs. The short-term financing was subsequently refunded with fixed rate financing which was also utilized to finance the majority of the remaining costs to construct the plant. A balance of costs remaining to complete the plant once the proceeds of the fixed rate financing were depleted was funded with the issuance of commercial paper notes.

NYPA has, on two occasions, refunded portions of the fixed rate bonds by issuing refunding bonds with lower overall yields. NYPA has also retired, on an accelerated basis, a portion of the commercial paper notes issued at the back-end of the project. While the 500 MW plant was funded 100% with debt, NYPA believes, from a business stand-point, financing future projects with a combination of debt and equity is more appropriate (please see discussion above).

1. Audited financial statements for its most recent fiscal years; or

Available at www.nypa.gov

2. Audited financial statements from Proposer's parent, if proposer does not have such financial statements; or

Not applicable

3. Explanation if the statements above cannot be provided and alternate information to demonstrate Proposer's financial capacity to complete and operate the proposed Project

Not applicable

NYPA self-finances its transmission and generation projects by issuing Revenue Bonds and Notes of NYPA, as well as using equity. With the exception of banks providing liquidity facilities (which have never been drawn down on) no third party financing is utilized.

See NYPA RFP Attachment 5 (Exhibit H)

NYSEG: NYSEG is a gas and electric corporation organized under the laws of the State of New York in 1852. NYSEG is an indirect, wholly-owned subsidiary of Iberdrola USA and serves approximately 880,000 electric and 195,000 natural gas customers in New York State.

Financing Plan – The MSSC project would represent a relatively insignificant increase (<5%) in NYSEG's overall capital budget during the construction phase. NYSEG would finance the MSSC project along with all of its other capital and operating needs with a mix of debt and equity consistent with its financing strategy. NYSEG's financing strategy is to maintain a capital structure that is consistent with the capital structure assumed in the establishment of rates. Currently that target is a 48% equity ratio and NYSEG's actual equity ratio was 50% at March 31, 2013. NYSEG limits the payout of dividends to maintain it target equity ratio and also has the support of its parent Iberdrola S.A., should additional equity capital be required. NYSEG has credit ratings of BBB+ / Baa1 / A- from S&P, Moody's and Fitch, respectively and has access to the debt capital markets for long-term debt funding. NYSEG also has short-term financing available through a $200 million commercial paper program and additional credit of up to $250 million available to it through Iberdrola USA.

1. Audited financial statements for its most recent fiscal years; or

See www.nyseg.com

2. Audited financial statements from Proposer's parent, if proposer does not have such financial statements; or

Not applicable

3. Explanation if the statements above cannot be provided and alternate information to demonstrate Proposer's financial capacity to complete and operate the proposed Project

Not applicable

Environmental Benefits of the Project (**Section 8.8**)

The MSSC project has tremendous environmental benefits. It does not contribute to water pollution or generate any hazardous waste. The project increases the power flow across the existing transmission system. Because the MSSC project transmits power from existing, in-state resources, it can be considered an environmental pollution avoidance project. Instead of having to construct a new power plant which would generate pollution, the MSSC project transmits existing electricity more efficiently.

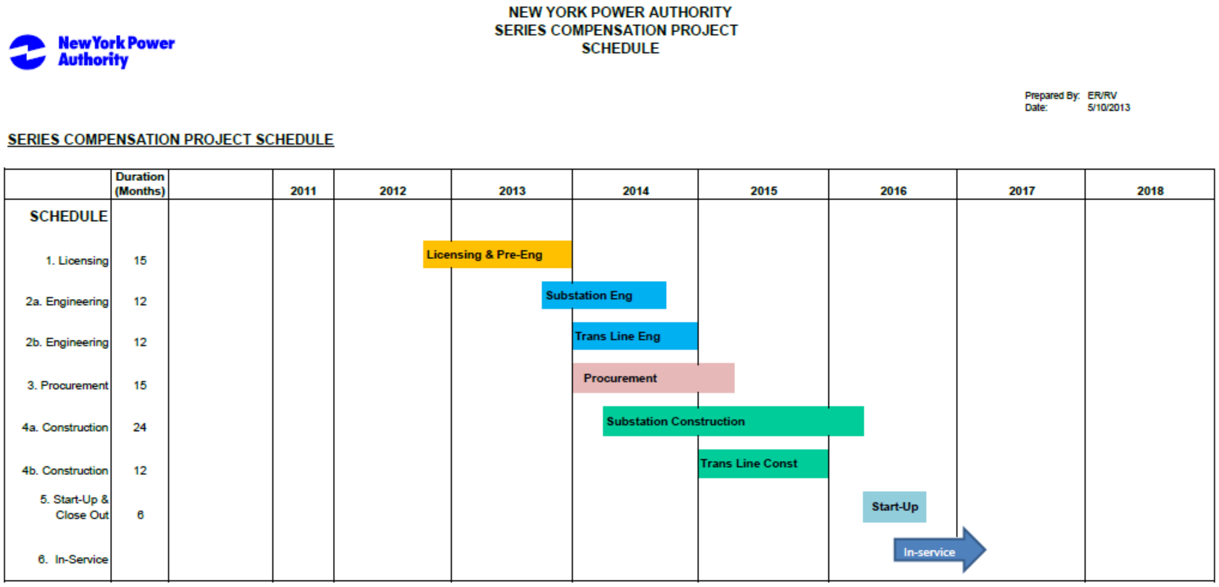
The MSSC project increases our capability to bring more power, including that from clean renewable sources, from upstate New York. This project does not require the acquisition of additional real estate for the series capacitors, and the transmission line reconductoring utilizes existing ROW.

There are no direct additional air emissions created as a result of this project, as opposed to those from new generation units. The MSSC project will have the necessary environmental permits in hand for the project to ensure construction is performed in an environmentally acceptable manner.

As identified in the New York Energy Highway Blueprint, this project is a significant component of the transmission upgrades in Northern New York that help facilitate renewable energy development.

Proposed Resources Development Plan and Schedule (**Section 8.9**)

In July 2012, NYPA contracted with an engineering firm to perform preliminary engineering services for the MSSC project. These services included identifying the size and locations for the series capacitor installations, identifying a proposed conductor type for the FCC-33 line, contacting equipment manufacturers for preliminary cost and schedule information, and determining a proposed construction and outage schedule to ensure commercial operation by June 1, 2016. The preliminary schedule of the MSSC project is shown below:



<u>Series Capacitor Installations</u>

The series capacitor banks must be installed along the three Marcy South lines: UCC2-41, EF24-40, and FCC-33. The criteria for locating the series capacitor banks includes operational performance, minimal community and environmental impacts, and effective operations and maintenance over the long term. Locations near the existing Marcy, Edic, Fraser, and Coopers Corners substations were evaluated. This evaluation included review of electrical drawings, existing substation equipment, site visits, and constructability. The primary locations were identified as 1 series capacitor installation, 900 MVAR, at the Marcy substation, and 2 series capacitor installations, 300 MVAR and 230 MVAR, at the Fraser Substation. These primary locations are on existing NYPA and NYSEG easements, under NYPA and NYSEG site control, outside of existing wetlands, and enable operations and maintenance of the installations to be performed by NYPA and NSYEG personnel going forward.

<u>Reconductoring of the 21.8 mile FCC-33 line</u>

The preliminary engineering services for the reconductoring of the FCC-33 line involved identifying a new conductor that is strong, lightweight, and has a higher thermal rating than the existing, single bundle 2156 ACSR. The required thermal ratings for the new conductor are based on the SIS that was performed by NYPA as part of the NYISO Interconnection process.

The preliminary engineering studies identified two High-temperature, Low-sag conductors that will meet the new thermal rating requirements: 3M ACCR 1962-T11 and CTC ACCC Chukar II. These conductors were modeled using PLS-CADD based on the NESC C2-2012 loading conditions.

The existing structures were then modeled with the new conductors to identify structures that may require modifications. Each of the two proposed conductors would require different structural modifications, and the final modifications will be determined based on the actual conductor chosen for installation during final design.

Detailed Design

As mentioned above, the preliminary engineering for the MSSC project has been completed with the identification of the preferred locations for the capacitor banks and the identification of two potential conductor types. The detailed engineering and design is currently underway. This will finalize the capacitor bank footprint size and location, the conductor type, and the required structure modifications, if any.

The SIS was completed and approved by TPAS on May 6. It is expected to receive final approval by the NYISO Operating Committee (“OC”) on May 20, 2013. Approval by the OC completes the NYISO Interconnection process. In addition to the NYISO SIS, a subsynchronous resonance study is currently underway to ensure nearby generators will not experience any damage from the series capacitors.

Proposed Date(s) for any PSC or FERC Orders

The current schedule for the MSSC project which enables an in-service date of June 1, 2016 is based on three events: 1) the PSC selection of the MSSC in Case 12-E-0503 during September 2013, 2) the issuance of the Amendment to the existing Article VII Certificate for the Marcy South during first quarter 2014, and 3) the issuance of all applicable permits for the FCC-33 line reconductoring during second quarter 2014.

As the MSSC project is expected to be transferred to the NY Transco, the following dates are also anticipated:

- PSC Approval of Section 70 asset transfer filing during the first quarter of 2014
- FERC approval of NY Transco formula rate during the middle of 2014
- FERC approval of NY Transco incentives during the middle of 2014
- FERC approval of cost allocation during the middle of 2014

Timeline for Award of EPC Contract and Equipment Fabrication

The MSSC project will involve an EPC contract for the series capacitors. The bid package is anticipated to be completed and issued during the Fall of 2013. Proposers will have eight weeks to respond to the EPC bid. Anticipated bidders include General Electric, ABB, and Siemens. All three companies have experience with series capacitor design and installation, and will warranty the equipment and installation. The capacitors are anticipated to be designed and installed within 18 months of contract award.

The reconductoring of the FCC-33 line will be performed as a design, bid, build. NYSEG is currently designing the new conductor and structure modifications and will be procuring the new conductor. It is anticipated that there is a 6 month lead time on the conductor. NYSEG will be procuring installation services and will be coordinating outages with the NYISO. The final design is anticipated to be completed by December 31, 2013.

Permitting and Licensing

In parallel with the detailed design effort, the appropriate permits and licenses will be obtained for the MSSC project. At a meeting with the Department of Public Service on May 3, 2013, NYPA and NYSEG obtained input from staff as to the licensing and permitting requirements for the MSSC project. These efforts are currently underway. A joint meeting with the NYSDEC and other potentially interested agencies is scheduled for May 21, 2013 to determine permitting requirements specific to these agencies.

Community Outreach Plan

NYPA and NYSEG will design an appropriate Community Outreach Plan for the MSSC project. It will include the following stages:

Stage 1: Project Announcement – Framing the Issues
During the first stage of the public outreach program, NYPA and NYSEG will:

- Refine the overall public outreach plan, including the objectives and key messages
- Confirm key audiences or stakeholder groups identified previously
- Establish timeframes for the outreach program, including a long range and more detailed short range schedule
- Assign responsibilities
- Begin the preparation of collateral materials, including a press release to announce the project
- Implement a pre-announcement contact program
- Announce the project

Stage 2: Route Selection – Reaching Out and Establishing a Dialogue
The MSSC project route is established and NYPA and NYSEG will be reaching out to stakeholders to establish a two-way dialogue. The information to be shared at this stage will consist primarily of the following:

- A clear articulation of the need for the project
- A description of the route and impact at the existing substation sites
- Transmission line design characteristics, estimating structure modifications
- Information on issues that may be easily anticipated, such as EMF

An effective public outreach program involves two-way communication. Thus, the purpose of the outreach is to initiate a dialogue, so NYPA and NYSEG can better understand the community's perceptions, concerns and issues, and address them through the design of the project, in the information that is shared, and in other creative ways that demonstrate responsiveness.

Activities proposed in this stage of the program will include:

- Development of a mailing list
- Conduct open house meetings

- Communication with the media
- Website development and maintenance
- Establish project telephone line and e-mail address
- Prepare collateral materials (i.e., fact sheets, newsletters, brochures)

Stage 3: Application Review – Managing Issues

Once NYPA's Article VII Amendment application is filed relative to the series capacitors and NYSEG's State Agency permit applications are filed relative to NYSEG's reconductoring, the public outreach program will focus on keeping stakeholders informed of the process and announcing the achievement of major milestones. In addition, the public outreach team will be available to support NYPA and NYSEG in issue management, which includes being aware of issues as they arise in the application review process, understanding the implications of them from a public relations standpoint, and devising an appropriate communications strategy. It is in this stage that having a team structure, close coordination, and good internal communication really pays off. For, although this stage of the process may proceed very smoothly with few issues surfacing at the community level, being able to anticipate significant community issues and respond quickly is important. The Public Affairs team will establish protocols for prompt and coordinated response to public inquiries and issues raised by opposition groups.

Activities during this stage will include:

- Convening small-scale meetings and individual briefings with key stakeholders about specific issues
- Issuing press releases as major milestones are achieved
- Updating the web page including timely responses to manage content and respond to inquiries, comments, and issues
- Mailing project updates or newsletters to stakeholders on the mailing list
- Maintaining awareness of opposition group positions through internet monitoring

The benefits of active use of the internet cannot be over-emphasized. A project-specific website or project link from NYPA's and NYSEG's website is expected to be available for dissemination of public information and permit application documents. This site will also provide a mechanism for public comments and requests for additional information, and will require regular monitoring to ensure responsiveness All internet postings by NYPA and NYSEG will be transparent, factually correct, and updated as often as necessary.

Stage 4: Design and Construction – Consolidating Community Support and Following Through

During construction, NYPA and NYSEG will keep the neighbors and customers informed of progress. To the extent that the team has been successful in communicating the benefits of the project, the community will be informed of how the project is going. Progress reporting will be accomplished through the media and/or periodic mailings (letters, newsletters, bill stuffers). There will also be a procedure in place for responding promptly and effectively to questions and complaints. Through the efforts invested up to this point, the framework will be established to enable NYPA and NYSEG to continue the public outreach efforts and ensure good community relations.

Equity and Debt Financing Plans

Please see Section 8.7.

Community Benefits

Please see Section 8.14

Taxes and/or Pilot Agreements

NYPA does not pay real estate taxes. NYSEG's portion of the project would be subject to real estate taxes.

Site Control Status

The series capacitors are being installed adjacent to the existing Marcy and Fraser substations. These will be under NYPA and NYSEG control, respectively. The FCC-33 line is existing and under the control of NYSEG.

Operations Plan

While the application of a series capacitor is new to the electric system at NYPA and NYSEG, the system is comprised of conventional power system devices currently installed at existing facilities operated and maintained by the utilities. The preventive maintenance practices for the system can be developed by reviewing the manufacturer's recommended procedures, in addition to, industry, NERC/NPCC, NYPA and NYSEG standard policies and procedures. A thorough review of the manufacturer's recommended procedures and maintenance intervals will be conducted to develop an optimal maintenance program and spare parts inventory.

As with any preventive maintenance program, it is recognized that historical operations and maintenance data provide valuable insight into the effectiveness of the preventive maintenance practices. As operations and maintenance experience is gained on the particular components, it is expected that the historical testing and trend data will enable the preventive maintenance program to be fine-tuned, with testing intervals for various components being increased or decreased, as required.

Maintenance outages will be scheduled based on the manufacturer's recommended practices, in addition to, industry, NERC/NPCC, NYPA and NYSEG standard policies and procedures. When safe and practical, maintenance will be performed on equipment while the series capacitor remains in service.

The utilities employ a staff of trained and qualified engineers and maintenance personnel familiar with operations and maintenance of power systems equipment. The proximity of the capacitor banks to the Marcy and Fraser substations allows for NYPA and NYSEG personnel to perform the inspections and maintenance in a cost effective manner. Additional training on manufacturer's specific equipment and procedures will be arranged, as necessary.

The existing ROW maintenance and line inspection practices for the FCC-33 line will continue with the use of NYSEG personnel. These practices are in accordance with NERC/NPCC, NYSEG and industry standard policies and procedures. The reconductoring of a portion of the line should not impact the current operation and maintenance practices.

Electric Interconnection Points

The MSSC project transmission corridor begins at the Marcy substation near Utica, New York and ends at the Coopers Corners substation near Monticello, New York. Both substations are located in Zone E, but the MSSC produces increased power flow into Zones F and G.

Status in NYISO Interconnection Process

The Final Report of the SIS for the MSSC project (NYISO- Queue #380) shows a transfer limit increase of 444 MW across the Total East Transmission Interface due to the series compensation. The Final Report of the SIS for the MSSC project was completed, approved by the NYISO's TPAS committee, and is expected to receive final approval by the NYISO OC on May 20, 2013. The OC's approval of the SIS completes the NYISO Interconnection Process. The series compensation increases power flow from Zone E into Zones F and G.

Environmental Justice

NYPA and NYSEG compared the location for the series capacitors and the 21.8 mile section of the FCC-33 line to the NYSDEC's data file of the Potential Environmental Justice Areas (PEJAs). This data file is comprised of sites that have met one or more of the NYS DEC criteria in the 2000 U.S. Census. According to this dataset, the closest PEJA to the Marcy substation is approximately 3 miles away. The closes PEJA to the Fraser Substation is approximately 13 miles away.

Cancellation Provisions

NYPA and NYSEG intend to include in any contract into which they enter in relation to the development and construction of the MSSC a right to terminate the contract at NYPA and NYSEG's election for any reason. Upon such termination, NYPA and NYSEG intend to require the contractor to stop performing all work and to cancel as quickly as possible all orders placed by it with subcontractors and suppliers, and to use all reasonable efforts to minimize cancellation charges and other costs and expenses associated with termination of work. NYPA and NYSEG will also seek to enter into fixed price contracts, with payment contingent upon the achievement of certain milestones, to the greatest extent possible. While NYPA and NYSEG intend to seek such terms, there can be no assurance that NYPA and NYSEG will be successful in achieving them. In this regard, NYPA and NYSEG note that much of the equipment the MSSC requires will be highly customized; as a consequence, NYPA and NYSEG do not expect to be able to cancel such orders (or that its contractor will be able to cancel such orders) once they are placed. NYPA and NYSEG would expect that any proposer seeking to develop and construct transmission projects would be subject to similar constraints.

Environmental Review **(Section 8.10)**

The installation of the series capacitors will require an Amendment to the existing Article VII Certificate for the Marcy South, Case 70126. The reconductoring of the FCC-33 line will require the completion of various studies and investigations as well as procurement of certain permits and approvals which will be coordinated with the NYSDEC.

The following Federal, State and local environmental laws and regulations have been assessed for applicability to this project. Initial coordination with these agencies has commenced and required permits and/or approvals will be acquired as outlined in the proposed schedule.

Federal Agency	**Regulations (Permit)**	**Applicability/Status**
U.S. Army Corps of Engineers (USACE) New York District	Clean Water Act - Section 404 Permit Nationwide Permit No. 12 *33 USC 1344*	A permit with the USACE is not expected. A Preconstruction notification will be required if certain thresholds are exceeded.
U.S. Fish & Wildlife Service	Federal Endangered Species Act *16 USC 1531* Migratory Bird Treaty Act *16 USC 703* Bald and Golden Eagle Protection Act *16 USC 668*	Process initiated. NY Natural Heritage program data request used to identify potential species concerns.
State Agency	**Applicability**	
New York State Department of Public Service, Public Service Commission (PSC)	Public Service Law - Article VII U.S. Clean Water Act - Section 401 Water Quality Certification *16 USC 1451*	Initial coordination with DPS staff to determine applicability of Public Service Law Existing structure heights not expected to increase.

New York State Department of Environmental Conservation (NYSDEC)	State Pollutant Discharge Elimination System (SPDES) Construction Stormwater Permit *6 NYCRR §750-1.21* Threatened and Endangered Species *6 NYCRR Part 182* Freshwater Wetlands Permit *6 NYCRR, Part 608; ECL Article 24* Protection of Waters Permit *6 NYCRR, Parts 663-665 Article 15* Catskill Park Preserve	Construction activities disturbing more than 1 acre will require a SPDES permit and SWPPP NY Natural Heritage program data request Initial assessment of SC bank location impacts, access road crossings and pulling stations to determine applicability of these permits. Existing easement
State Historic Preservation Office (SHPO)	Section 106 Consultation under the National Historic Preservation Act (NHPA) – if federal permits/approval required Section 14.09 of the New York State Historic Preservation Act *16 USC 470*	Visual assessment may be performed only if structure heights increase significantly. Phase 1 archeological assessment to be performed for those areas not previously disturbed.
Local		
Town of Marcy Oneida County	Local Ordinances	
Town of Delhi Delaware County	Local Ordinances	
Town of Hamden Delaware County	Local Ordinances	
Town of Colchester Delaware County	Local Ordinances	
Town of Rockland Sullivan County	Local Ordinances	
Town of Thompson Sullivan County	Local Ordinances	
NYC Department of Environmental Protection	Approval of construction activities on NYC water supply lands	SWPPP used to eliminate potential stormwater runoff concerns in the Pepacton Reservoir

In addition to the permits identified above, an electromagnetic field (EMF) calculation will be performed in accordance with the DPS guidance. Geotechnical studies are also required at the locations of the series capacitors.

A MSSC website will be established and contain a repository of all relevant permits, environmental studies, and agency correspondence.

Pricing for Transmission Projects **(Section 8.11.2)**

CONFIDENTIAL AND REDACTED

Halting Costs **(Section 8.13)**

CONFIDENTIAL AND REDACTED

Other Requirements **(Section 8.14)**

The MSSC project will be constructed on existing ROWs and existing easements. No new ROW is required. Based on the capital cost of $76 million, 150 man years will be required to complete the project.

Compliance Statement **(Section 8.15)**

All products or services provided by NYPA and NYSEG for the MSSC project will be in compliance with all applicable legal and regulatory requirements.

Exhibit A

Location of Marcy South Lines

CONFIDENTIAL AND REDACTED

Exhibit B

Proposed Series Compensation Installation at Marcy

CONFIDENTIAL AND REDACTED

Exhibit C

Proposed Series Compensation Installation at Fraser

CONFIDENTIAL AND REDACTED

Exhibit D

Example of a series capacitor installation

CONFIDENTIAL AND REDACTED

Exhibit E

Example of H-frame wood pole structure

CONFIDENTIAL AND REDACTED

Exhibit F

NYPA owned Generating and Transmission Facilities

CONFIDENTIAL AND REDACTED

Exhibit G

NYPA RFP, Attachment 3

CONFIDENTIAL AND REDACTED

Exhibit H

NYPA RFP Attachment 5

CONFIDENTIAL AND REDACTED

Exhibit I

NYPA RFP Attachment 7

CONFIDENTIAL AND REDACTED

Neil H. Butterklee
Assistant General Counsel

May 20, 2013

VIA E-MAIL
Honorable Jeffrey C. Cohen
Acting Secretary
State of New York
Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re: Case 12-E-0503 – Con Edison Filing of Supplemental Information Regarding its Staten Island Unbottling Project

Dear Acting Secretary Cohen:

On February 1, 2013, in response to a November 30, 2012 order from the Public Service Commission ("Commission") in this proceeding, Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") and the New York Power Authority ("NYPA") filed their Indian Point Contingency Plan ("Plan") which included a proposal to build three Transmission Owner Transmission Solutions ("TOTS") as well as a plan for NYPA to issue a request for proposals ("RFP") for third party transmission and generation solutions. The Plan contained significant details regarding the three TOTS. In the Commission's March 15, 2013 Order in this proceeding (the "March 15th Order"), the Commission required Con Edison and NYPA to supplement the description of their TOTS with additional information so that the level of information submitted by Con Edison and NYPA to the Commission was comparable to the level of information requested from third party respondents to the NYPA RPF. Accordingly, Con Edison hereby files its supplemental information with respect to the Staten Island Unbottling ("SIU") project.

As indicated in the Plan and in the accompanying materials, the SIU project is a new resource that interconnects within New York Independent System Operator ("NYISO") load zone J and can be in service by June 2016. The SIU project meets the requirements necessary to be a solution for the retirement of the Indian Point Energy Center ("IPEC"). In addition, this

Consolidated Edison Company of New York, Inc.
4 Irving Place – Room 1875-S New York, NY 10003 212 460 1089 212 677 5850 fax butterkleen@coned.com

project provides additional benefits beyond transmitting replacement energy in the event that the IPEC retires.

Consistent with the requirements of the March 15th Order (p.18), the project costs described in this filing represent a good faith preliminary engineering estimate for the project. That being said, it is possible that the project's costs may change as project details are further defined.

Please feel free to contact me if you have any additional questions.

Very truly yours,

/s/ Neil H. Butterklee

Consolidated Edison Company of New York, Inc.

Additional Information on Transmission Owner Transmission Solution for Indian Point Contingency Plan:

<u>Staten Island Unbottling Project</u>

<u>May 20, 2013</u>

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8.2 Executive Summary

As shown herein, the New York State Public Service Commission ("Commission") should select Consolidated Edison Company of New York, Inc.'s ("Con Edison" or the "Company") Staten Island Unbottling ("SIU") project as one of the solutions in this proceeding for the following reasons:

1. The project can be delivered by the June 2016 deadline and has a clear head start because it does not need an Article VII certificate and it involves incremental investments to existing transmission assets;
2. The project addresses the reliability needs that would exist if the Indian Point Energy Center ("IPEC") were to retire and provides benefits throughout the State even if the IPEC does not retire.
3. Its estimated costs are reasonable; and
4. The project addresses the public policy needs specified in the Governor's *New York Energy Highway Blueprint* ("Blueprint").[1]

On February 1, 2013, in response to a November 30, 2012 order from the Commission in this proceeding, Con Edison and the New York Power Authority ("NYPA") filed an Indian Point Contingency Plan ("Plan") which included a proposal to build three Transmission Owner Transmission Solutions ("TOTS") as well as a plan for NYPA to issue a request for proposals ("RFP") for third party transmission and generation solutions. One of the TOTS is Con Edison's SIU project.

The SIU project will unbottle generation and transmission resources on Staten Island. It is a new resource and will be located in NYISO Zone J. The initial option for this project was to install a new 345kV feeder and the forced cooling of four existing 345 kV feeders; the new 1.5 mile feeder, interconnecting the Goethals substation to the Linden substation, would mitigate a contingency within New York City by installing a new double leg feeder into new positions at the Goethals and Linden substations. Based upon additional preliminary engineering and design work, the Company made certain changes to the project design. Instead of a new feeder installation, splitting an existing feeder between Goethals and Linden Cogen substations will provide a similar solution at a lower cost and with lower environmental impacts. The forced cooling of the existing four 345 kV feeders remains in the project scope and will increase transmission capacity between the Goethals, Gowanus, and Farragut substations. The forced cooling aspects of the project include the installation of ten refrigeration plants to increase transmission capacity between Goethals, Gowanus, and Farragut substations on the four 345

[1] A copy of the Blueprint can be found at: http://www.nyenergyhighway.com/PDFs/Blueprint/EHBPPT/.

kV feeders 25, 26, 41, and 42. The SIU project would be located in Staten Island and Brooklyn, New York and Union County (Linden), New Jersey.

As indicated in the Plan and in the accompanying materials, the SIU project is a new resource that can be in service by June 2016. A significant part of the Company's ability to deliver the SIU project within the specified timeframe is due to the fact that the SIU project does not need an Article VII permit. In addition, based an analysis conducted by Con Edison, the NYISO determined that a full System Impact Study ("SIS") was not required.

The Company's initial good faith estimate for this project was $312 million. Based upon additional preliminary engineering and design work, the Company made certain changes to the project design as described above. Based upon these changes, the new current good faith estimate is $248 million. While this project is being submitted by Con Edison, it is anticipated that the SIU project will eventually be completed and owned by the New York Transmission Company ("NY Transco") and will be one of several Federal Energy Regulatory Commission ("FERC") regulated transmission projects owned by the NY Transco. As such, the rates for this project will be based on a cost of service rate and, consistent with the requirements of the March 15th Order, will not be based on a fixed price nor will it be a merchant transmission facility. As the Commission recognized in its March 15th Order, "[w]e understand the TOTS cost estimates to be good faith estimates, rather than 'not to exceed' values."[2] While the Commission directed Staff to "evaluate TO and RFP projects on as comparable a basis as possible, it is neither necessary nor appropriate to provide identical cost recovery provisions for each."[3] It is anticipated that once it is in service, the SIU facility will be under the operational control of the New York Independent System Operator ("NYISO") and its rates included in the NYISO's Open Access Transmission Tariff ("OATT").

The SIU project is an upgrade to the statewide interconnected transmission grid. The state-wide benefits associated with upgrades to an interconnected transmission system were recognized in the Blueprint, which stated that:

> Ensuring the efficient transmission of power by reducing bottlenecks and developing advanced smart technologies improves overall electric system operation and optimizes the use of existing assets in New York by allowing lower-cost and cleaner power to reach consumers. Investments in the transmission and distribution systems can reduce customer costs over the long-term, improve safety and reliability, and protect the

[2] March 15 Order, p.18.
[3] Id.

environment while immediately creating jobs and economic development.[4]

The Federal Courts have also found that "[w]hen a system is integrated, any system enhancements are presumed to benefit the entire system." *W. Mass Electric Co. v. FERC*, 165 F. 3d 922, 927 (D.C. Cir. 1999).

Among the public policy goals that the SIU project will contribute to is an increase in economic development within New York State, including increased employment and increases in local tax revenues. Accordingly, the SIU project will provide benefits beyond its ability to replace some of the energy and capacity should the IPEC retire.

8.3 Description of Project

Unbottling Staten Island generation and transmission resources will require the splitting two legs (called the L&M legs) of an existing 345kV feeder and the forced cooling of four existing 345 kV feeders. The feeder split would mitigate a controlling contingency within New York City by establishing a second feeder into a new position at the Goethals and Linden substations. The forced cooling of the existing four 345 kV feeders will increase transmission capacity between Goethals, Gowanus, and Farragut substations. The Project would be located in Staten Island and Brooklyn, New York and Union County (Linden), New Jersey. This project is located in NYISO Zone J.

Splitting an existing feeder in-between Goethals and Linden Cogen will require new bus section installations. Both substations will need new 345kV breakers and bus modifications to establish new bus positions for the feeders and to maintain feeder separation. Linden Substation is an SF6 (sulfur hexafluoride) station that requires SF6 equipment to expand the station. Although Goethals Substation is an open air substation, due to limited space, the new bus position needs to be established using SF6 equipment. The scope also includes replacing the trifurcating joint at Linden Cogen and Goethals Substations, installing approximately 350 feet of 345kV cable at Linden Cogen and 500 feet of 345kV cable in Goethals Substation.

The project also includes the installation of ten refrigeration plants to increase transmission capacity between Goethals, Gowanus, and Farragut substations on the four 345kV feeders 25, 26, 41, and 42. Six of these plants will be installed in support of feeders 25 and 26; one each at the Gowanus and Goethals Substations and four along the route of the feeders. The plants along the route need to be sited equidistant to each other and the interconnecting

[4] Blueprint, p. 10.

stations. One of these locations is the current Bay Street property, which will hold two cooling plants.

The other property will hold another two plants in support of feeders 25 and 26 and will need to be acquired. The next four plants will be installed in support of feeders 41 and 42; two each at Gowanus and Farragut Substations. A one-line diagram of the project and a diagram illustrating the locations of the refrigeration plants are included in Exhibit A.

The impact of the SIU project towards reducing N-1/-1 deficiency post Indian Point Shutdown is approximately 440 MW. This impact is based on an application of the NYC Reliability Criteria. In general, transmission projects, such as SIU, will have an interaction with other transmission or generation projects that can be either positive or negative (*i.e.,* the stated impact may increase or may decrease). Therefore, it is critical that when a comprehensive portfolio analysis is conducted the impact of this Project would be re-calculated.

8.4 Proposer Experience

Con Edison and O&R are regulated public utilities that are subsidiaries of Consolidated Edison, Inc. ("CEI"), a holding company. In 2012, CEI had $41.2 billion in assets and $12.2 billion in revenues (please see CEI's 2012 annual report). Con Edison serves a 660 square mile area with a population of approximately ten million people. In that area, Con Edison serves approximately 3.3 million electric customers, 1.1 million gas customers, and 1,700 steam customers. Con Edison provides electric service in New York City and most of Westchester County, gas service in parts of New York City and steam service within the borough of Manhattan. Con Edison has approximately 1,180 circuit miles of transmission, including 438 circuit miles of overhead and 742 circuit miles of underground transmission. [5] Con Edison was incorporated in New York State in 1884 and its corporate predecessor, the New York Gas Light Company was founded in 1823.

O&R and its utility subsidiaries, Rockland Electric Company and Pike County Light & Power Company, operate in Orange, Rockland and part of Sullivan counties in New York State and in parts of Pennsylvania and New Jersey, and serve a 1,350 square mile area. O&R provides electric service to approximately 300,000 customers and gas service to approximately 100,000 customers in southeastern New York and in adjacent areas of northern New Jersey and northeastern Pennsylvania. O&R has approximately 558 circuit miles of transmission.

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[5] A list of Con Edison's and O&R's transmission and generation facilities can be found in the *2013 Load and Capacity Data, A Report by the New York Independent System Operator "Gold Book,"* which is located at: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2013_GoldBook.pdf.

Con Edison is a voting member and O&R is a non-voting affiliated member of the Transmission Owners sector of the NYISO. As transmission owners in New York, Con Edison and O&R helped to create the NYISO and its markets. As the utility responsible for providing electric, gas and steam service to the New York metropolitan area, Con Edison has developed numerous projects over the last ten years, all focused on providing safe, reliable and efficient service to its customers. Recently, Con Edison constructed and put into service the M29 transmission line.

With respect to project management, work on the SIU project will initially be managed by Con Edison engineers and project management professionals. Most of the work will be conducted by outside engineering and construction firms.

8.5 Project Information

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It is anticipated that, while Con Edison will commence development of the SIU project, it will transfer the Project, as soon as it is able to do so, to NY Transco, a New York limited liability company proposed to be formed in July 2013 and co-owned by the following entities or their newly formed special purpose affiliates (subject, in the case of the public authorities, to the enactment of legislation enabling their participation): Con Edison/O&R, Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"), New York State Electric & Gas Corporation and Rochester Gas & Electric Corporation (together, "NYSEG/RG&E"), NYPA, Long Island Power Authority ("LIPA") and CH (collectively, the "NYTOs").

Con Edison's DUNS Number is 006982359.

8.6 Disclosure Statements

Neither Con Edison nor any of its affiliates have, during the past five years, been judged or found by any court or administrative or regulatory body to have defaulted on or failed to comply with any material obligation related to the sale or purchase of power (capacity, energy and/or ancillary services), transmission or natural gas.

Neither Con Edison, nor any of its trustees or "executive officers" (as defined by Rule 3b-7 promulgated under the Securities Exchange Act of 1934, as amended) or affiliates have, during the past five years, been convicted of (a) a felony, or (b) any crime related to the sale or purchase of electric power (capacity, energy and/or ancillary services), transmission or natural gas, conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions, or collusive bidding or other procurement or sale-related irregularities.

8.7 Financial Capacity to Complete and Operate the Proposed Project

The Company has completed the Financial Data Sheets, included as Attachment 5 to the NYPA RFP and attached hereto as Exhibit B, with respect to the Project. As discussed further below, the exhibits assume that the SIU Project will be transferred to NY Transco around spring 2014 and subsequently developed and financed by NY Transco.

Prior to its transfer to NY Transco, Con Edison will finance construction of the SIU Project in the same way that it currently finances its capital needs: by issuing long-term debt in the capital markets. Debt financing at Con Edison must be approved by the Commission via a financing order. Under the Company's current financing order, Con Edison has authorization to issue $3.5 billion of debt through December 2016. In addition, the Company's financing may be limited by the capital structure approved by the Commission. The Company currently has an approved equity ratio of 48%. Funding for the Project will take into consideration the Company's approved equity ratio.

Information concerning Con Edison's financial condition may be obtained upon review of the Company's audited financial statements, which are available publicly and accessible on the Company's website, at www.conedison.com or on the Securities and Exchange Commission's website, at www.sec.gov/edgar. The Company's unsecured debt is rated A3, A- and A-, respectively, by Moody's Investor Service, Inc. ("Moody's), Standard & Poor's Corporation ("S&P") and Fitch Ratings, Inc. ("Fitch"). CEI's long-term credit rating is Baa1, BBB+ and BBB+, respectively, by Moody's, S&P and Fitch. The commercial paper of both the Company and CEI is rated P-2, A-2 and F-2, respectively, by Moody's, S&P and Fitch. Securities ratings assigned by rating organizations are expressions of opinion and are not recommendations to buy, sell or hold securities, and may be revised or withdrawn at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating.

Accordingly, Con Edison expects to transfer the Project to NY Transco as promptly as possible upon the commencement of its operations (which is anticipated to occur following (i) enactment of necessary legislative changes and procurement of approvals, if applicable, of the Comptroller and/or Attorney General of the State of New York with respect to NYPA and LIPA's participation, as well as (ii) receipt of approvals by FERC of a transmission formula rate schedule and incentives, and (iii) implementation of cost allocation and cost recovery mechanisms through the NYISO's tariff, all of which are expected by the middle of 2014). It is expected that NY Transco will be able to obtain investment grade construction debt financing once its rate is approved by FERC, and that NY Transco will also receive various FERC incentives, including construction work in progress, that will reduce construction risk. Equity support will be provided to the Transco by the NYTO's investing affiliates during construction and, to the extent necessary, thereafter to support continued operations. It is anticipated that the NY Transco will make its formula rate filing at FERC during the summer of this year. As such, it is premature to specify the exact debt / equity ratio that will be approved by FERC for this project. However, for informational purposes, a 50/50 debt to equity capital structure is assumed in Exhibit B.

8.8 Environmental Benefits of Project

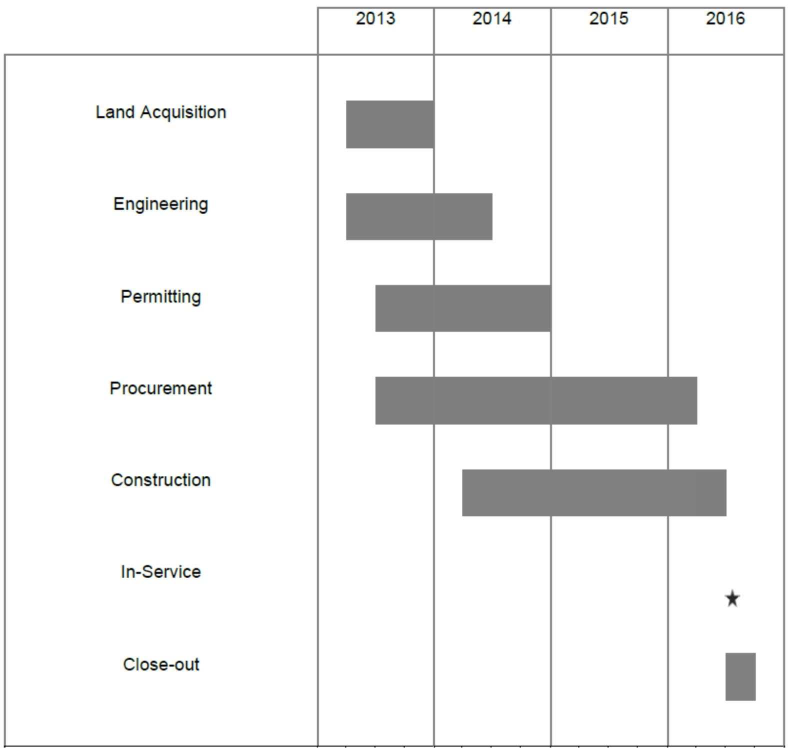
The Project's primary objectives are to meet the public policy goals stated in the Blueprint including: reducing congestion, providing economic benefits to local communities, encouraging renewables, enhancing the long-term reliability of the bulk power system and planning for a possible IPEC retirement. With respect to meeting the reliability need if the IPEC should retire, the SIU project will reducing the severity of a second contingency violation in New York City, and increasing transfer capability between the Staten Island generation pocket and the rest of the 345kV system in New York City.

The SIU project would allow greater access to generation resources in the Pennsylvania Jersey Maryland ("PJM") regional transmission organization. It is expected to increase imports from PJM into Staten Island and reduce the dispatch of local fossil generation within New York City and Long Island, leading to improved air quality and environmental health benefits to the densely populated metropolitan area.

8.9 Proposed Resource(s) Development Plans and Schedule

The following represents the current high-level schedule and work plan for the development of the SIU Project.

MS Project Gant Chart



Proposed In-Service Date May 2016

No contracts with NYPA are necessary to achieve this in-service date.

Proposed Date for PSC and FERC Orders

The following represent the proposed dates for key PSC and FERC approvals that are necessary to achieve the June 2016 in-service date.

1. PSC selection in Case 12-E-0503 – September 2013
2. FERC approval of NY Transco formula rate – mid 2014
3. FERC approval of NY Transco incentives – mid 2014
4. FERC approval of cost allocation for Transco projects – mid 2014
5. PSC approval of Section 70 asset transfer filing – 4th Quarter 2014

Timeline for award of Engineering, Procurement and Construction ("EPC") Contract

The EPC Contract will be performed in phases. The first phase, engineering, will be awarded by the third quarter of 2013.

Lead Times for Major Equipment

The following are the lead times for major equipment:

- Refrigeration Plants = **[Redacted]**
- 345kV SF6 Bus and breakers = **[Redacted]**

Plans for Construction and Operation

The construction work is expected to be performed by an EPC contractor. Once the project is operational, Con Edison may perform operation and maintenance ("O&M") services for the NY Transco with respect to the SIU project in accordance with the terms of an O&M Agreement between the parties and consistent with the affiliate rules of the Commission and FERC. Similar to other transmission assets in the State, the facility will be under operational control of the NYISO.

Community outreach plans

Con Edison's government relations and public affairs personnel will provide appropriate community outreach support for the SIU project until this function is assumed by the appropriate resources of the NY Transco. The organizational experience supporting major inter-utility projects such as the BEC and Hess projects and the construction of new substations ensures that the community outreach efforts will be successful.

Equity and Debt Financing Plans

Please see description of financing plans in section 8.7.

Contractor Experience

This information is not yet available as the EPC and other contractors have not yet been procured for this project. It is expected that contractors with appropriate experience and expertise will be hired at a reasonable cost.

Community Benefits

Please see the response to section 8.14 dealing with the Project's economic development benefits.

Taxes and/or PILOT agreements

Because transmission facilities are real property under the New York State Real Property Tax Law, the Company anticipates that local property taxes will be levied with respect to this facility by each municipality where the facility will be located and to New York State. Although property taxes throughout the State are generally based on the property's reproduction cost new less depreciation, rates vary significantly from jurisdiction to jurisdiction as well as from year to year, and therefore cannot be predicted with certainty. A generic assumption was used for estimating property taxes in the financial data sheet included in Exhibit B.

Site Control Status and Plans for Site Control

The following represents the site control plan for the SIU project.

- The project will affect 4 substations, Goethals, Gowanus, and Farragut (owned by Con Edison) and Linden Cogen (owned by Linden Cogen).
- Any parties requesting access / visitation to Con Edison substations shall have escorted access with Con Edison employees, at a time acceptable to Con Edison.
- Con Edison will request access to Linden Cogen's substation as needed throughout the project and will be contingent upon their availability.
- During construction, the project team will follow appropriate plans regarding the appropriate site control plans such as security guards, additional gate/barriers, and other related items.

Operations Plan

Con Edison estimates that the following incremental O&M will be required once the SIU facility is in service. Preliminary cost estimates are included in Exhibit B. The following is a list of the expected O&M activities once the assets are in-service:

- Manhole cleanings on an annual basis
- Increased operator staffing during summer operational period
- Operating coverage during scheduled and maintenance work
- Online monitoring for the new plants
- FM200 vendor inspection
- Third party fire monitoring
- Smoke detection semi-annual inspection and service
- Maintenance functions such as Fire extinguisher inspection and replacement, emergency lighting compliance, suppression system inspection, filter replacement.
- Minor facility repairs
- Refrigeration contractors to inspect as per manufacturer recommendation

Property Acquisition

The first two of the six cooling plants will be located at the terminal stations of feeders 25 and 26. The next two of the six cooling plants required to cool feeders 25 and 26 will be installed at the Bay Street property. The last two cooling plants will require the acquisition of new property. This new property needs to be located as close as possible to the route of feeders 25 and 26, large enough to hold two refrigeration plants, and needs to be located at the midpoint of Goethals Substation and the Bay Street plant. Acquisition of the property has not been completed, but work has begun as part of the initial authorization to proceed with this project. The property must be procured to accommodate the service date of May 2016. Due to potential land siting issues associated with the new property, the timeline and cost estimates to acquire the land and associated engineering and design elements may be subject to change, including potential higher land costs or increased project costs to accommodate design using available land. As such, the overall cost of the SIU project may be higher than the current estimate.

NYISO Interconnection Status

On January 18, 2013, the NYISO, as per Section 2.4.2 of the NYISO Transmission Expansion and Interconnection Manual,[6] determined that a full SIS was not required. Thus, no further NYISO studies are required. A one-line of the proposed interconnection points is included in Exhibit A.

Environmental Justice Issues

Con Edison will conduct an analysis of potential environmental justice concerns for the Indian Point Contingency projects in accordance with NYSDEC Commissioner Policy CP-29, *Environmental Justice and Permitting.* The analysis will identify any Potential Environmental Justice Areas to be affected, describe the existing environmental burden on the Potential Environmental Justice Area and evaluate the potential burden of any significant adverse environmental impact on the area.

EPC Cancellation provisions

Con Edison intends to include in any contract into which it enters in relation to the development and construction of the Project a right to terminate the contract at Con Edison's election for any reason. Upon such termination, the Company intends to require the contractor to stop performing all work and to cancel as quickly as possible all orders placed by it with subcontractors and suppliers, and to use all reasonable efforts to minimize cancellation charges and other costs and expenses associated with termination of work. The Company will also seek to enter into fixed price contracts, with payment contingent upon the achievement of certain milestones, to the greatest extent possible. While Con Edison intends to seek such terms, there can be no assurance that the Company will be successful in achieving them. In this regard, the Company notes that much of the equipment the Project requires will be highly customized; as a consequence, the Company does not expect to be able to cancel such orders (or that its contractor will be able to cancel such orders) once they are placed. The Company would expect that any proposer seeking to develop and construct transmission projects would be subject similar constraints.

8.10 Environmental Review

The environmental permitting plans for the Indian Point Contingency Projects were presented in earlier Con Edison PSC filings and are incorporated herein by reference.

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[6] The Staten Island Unbottling project is contingent on the use of the Co-Gen position at the Linden Substation.

Permitting Plan:

The following sets forth a preliminary list of major permits/approvals which are expected to be filed (additional permits may also be required). These filings and reviews will take approximately six months to one year to complete. The exact timeframe would be determined through a pre-application conference with the New York State Department of Environmental Conservation ("NYSDEC"), Board of Standards and Appeals, the NYC Fire Department, and the New York City Department of Buildings to discuss the project and confirm permitting requirements.

1. NYC Zoning/Land Use Approval:

    a. Land use approval needed for cooling plants proposed outside existing Con Edison substations

    b. An application will need to be filed with the NYC Board of Standards and Appeals (BSA) and the local Community Board. An environmental impact review will also need to be submitted under the City Environmental Quality Review (SEQR as implemented by NYC)

    c. Once the approval process has been completed, Con Edison would need to apply for and obtain the necessary NYC construction approvals

8.11 Pricing – Transmission Project

Cost Estimate

[Redacted]

Pricing Assumptions

[Redacted]

Transmission Rates

[Redacted]

Supporting Financial Exhibits

[Redacted]

8.13 Halting Costs

Due to the unique nature of transmission projects, Con Edison will need to purchase equipment that may not be usable for any other project. As such, the halting mechanisms reflect the fact that once equipment is ordered, Con Edison must be able to recover 100% of the cost of such equipment, less any reductions available from cancellation provision in the procurement contract and realized salvage value. The halting mechanism also recognizes that in order to meet the In-Service Deadline, Con Edison has started preliminary engineering work for the project as well as steps necessary for land acquisition and will start equipment procurement activities as early as the third quarter of 2013. Thus, the halting mechanism must provide for the full recovery of costs incurred, as well as any contractual cancellation costs associated with such activities. It should also be noted that equipment procurement, engineering, and some construction activities will start even though not all of the required regulatory permits (environmental or community) will have been obtained as of this point in the project development schedule.

Recognizing the potential cost impacts to customers for the SIU project, Con Edison can state the estimated costs that it will incur for the SIU project at particular key points in time. Importantly, these estimates are based on conceptual project scopes and represent an order of magnitude reference for future project costs. As preliminary engineering and project tasks proceed, additional detail and certainty will support updated cost estimates. With respect to the SIU facility, the estimated costs of halting the project at the key points in time are shown below:

Staten Island Un-bottling Project	Date Halted	Estimated Partial At Risk Cost*
(Project Total: $248,000,000)	9/30/2013	**[Redacted]**
	3/31/2014	**[Redacted]**
	12/31/2014	**[Redacted]**
* The "Estimated Partial At Risk Cost" includes only an estimate of the committed dollars and do NOT include any cancellation charges that would be imposed by the contractors		

and equipment suppliers. The “Estimated Partial At Risk Costs” will be adjusted at the time of halting to include these costs. These costs are based on a 2016 in-service date estimate.

8.13 Cancellation Clauses

See response to item 8.9.

8.14 Other Requirements

List of Required Easements

Siting of the new refrigeration plant requires the purchase of new property, has not been completed, and is dependent on zoning and available properties, but it is anticipated to be purchased in a manufacturing zoned location in Staten Island. If not, special use permits will be required. At this time, no additional land rights are required to construct the substation upgrades at either Goethals or Linden Cogen substation in order to establish new bus sections for splitting the feeder.

Economic Development Benefits

Along with the other transmission projects proposed by the NY Transco in PSC Case No. 12-T-0502, this project is being proposed in order to accomplish the goals and objectives of the AC Order and the IP Order. In the AC Order the Commission sought transmission projects that increase transfer capability through the Central East and UPNY/SENY interfaces.[7] In the IP Order, the Commission sought solutions that could address the need that would result if the IPEC were to retire. Both of these orders seek transmission solutions to meet the objectives of the Blueprint. As described in this submission as well as in the Plan and in the NY Transco January 25, 2013 filing in Case 12-T-0502, this Project will provide the public policy benefits specified in the Blueprint.

Among the public policy goals that the SIU project will contribute to is an increase in economic development within New York State. Specifically, the SIU Project is estimated to cost approximately $248 million in 2016 dollars. As a result of this investment, the New York State economy will reap significant economic development benefits in the form of increased employment and increases in local tax revenues.

[7] AC Order, p. 2.

Based on analyses performed by the Working Group for Investment in Reliable and Economic Electric Systems (the "WIRES" group) in conjunction with the Brattle Group, this $248 million of investment will support an estimated 1,050 direct full time equivalent ("FTE") jobs and estimated 3,200 total FTE jobs.[8] The directly supported jobs represent those related to domestic construction, engineering and transmission component manufacturing. Indirect job stimulation represents suppliers to the construction, engineering and equipment manufacturing sectors as well as jobs created in the service industries (*i.e.*, food and clothing) supporting those directly and indirectly employed. The SIU project is also estimated to increase annual local tax revenue by approximately $6 to $9 million.[9]

Statement with Respect to NYPA Appendixes and Bid Documents

It is intended that cost recovery for the SIU project will be accomplished through regulated transmission rates and not via a contract with NYPA. As such, the provisions set forth on the NYPA appendixes and the bid documents are inapplicable to the SIU project. That being said, the Company is providing the attached documents to demonstrate its commitment to equal opportunity and diversity and to aid the Commission in reaching its decision regarding which projects should be selected. This statement and the inclusion of these documents satisfy the requirements of the Commission's March 15th Order in Case 12-E-0503, which required that Con Edison provide information that is comparable and at the same level as that sought from official responders to the NYPA RFP.

Accordingly, Con Edison has attached the following documents as Exhibit E to this response:

1. Policy on Sexual Harassment
2. Policy on Equal Employment Opportunity
3. Employment of Individuals with Disabilities, Disabled Veterans, and Other Qualified Veterans

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[8] The direct and total job numbers are based on generic information included in the May 2011 report entitled *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, which was developed by the WIRES group in conjunction with the Brattle Group. The report concluded that every $1.0 billion of transmission investment supports 4,250 direct FTE years of employment and 13,000 total FTE equivalent years of employment. This report can be found at the following link: http://www.wiresgroup.com/images/Brattle-WIRES_Jobs_Study_May2011.pdf.

[9] The estimated annual local tax revenue associated with these projects is based on a factor of approximately 2 to 3% of project capital costs, which is consistent with the NY Transco estimate provided in Case 12-T-0502.

In addition, the Company's 2012 Diversity Annual Report can be found at: 2012 Diversity Annual Report

8.15 Compliance Statement

It is anticipated that the Project will comply with applicable laws and regulations.

8.16 Project Benefit / "No Regrets" Analysis

In addition to the economic development benefits described above, the SIU project provides public policy benefits to New York State even if the IPEC does not retire. The project provides marginal economic and environmental benefits across the state by enabling more energy from potentially more efficient and lower cost generation resources in New Jersey to serve load within New York State. By unbottling generation on Staten Island, the project also would enable the delivery of solar and wind resources on Staten Island, should such resources be developed.[10] Even if IPEC does not retire, the project benefits long-term reliability by mitigating the controlling contingency within New York City and also provides more operational flexibility during maintenance outages.

[10] The City of New York has discussed potential development of such resources on its Fresh Kills site.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission	**)**	
To Review Generation Retirement	**)**	**Case 12-E-0503**
Contingency Plan	**)**	

REVISED INDIAN POINT ENERGY CENTER DEMAND MANAGEMENT PLAN OF CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY, AND NEW YORK POWER AUTHORITY

INTRODUCTION

Pursuant to the April 19, 2013 order of the New York State Public Service Commission ("Commission") in the above-referenced proceeding,[1] Consolidated Edison Company of New York, Inc. ("Con Edison") and the New York State Energy Research and Development Authority ("NYSERDA"), in consultation with the New York Power Authority ("NYPA"), hereby submit their revised plan (the "Revised Plan") for energy efficiency, demand reduction, and combined heat and power ("CHP"). Con Edison, NYSERDA and NYPA (collectively the "Organizations") have jointly prepared the Revised Plan.

Specifically, the Revised Plan includes a joint program, to be implemented by Con Edison and NYSERDA, with support from NYPA, designed to achieve 100 MW of cost-effective peak demand reduction by summer 2016 within the Con Edison service territory. The 100 MW demand reduction will be coincident with the system peak and will be in addition to peak demand reductions that are currently included in the New York Independent System Operator ("NYISO") Resource Needs Assessment ("RNA"). In addition to the 100 MW, the

[1] Case 12-E-0503, *Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans*, Order Upon Review of Plan to Advance Transmission, Energy Efficiency, and Demand Response Projects ("April 19th Order").

Revised Plan also includes a 25 MW CHP program to be administered by NYSERDA and NYPA's plan to save an additional 15 MW through the Build Smart NY program. Accordingly, the Organizations respectfully request that the Commission approve the Revised Plan and allow the Organizations to move forward with its implementation.

I. BACKGROUND

The initial Indian Point Contingency Plan, filed with the Commission by Con Edison and NYPA on February 1, 2013 ("Initial Plan"), set forth a flexible approach that was designed to build upon Energy Efficiency Portfolio Standard ("EEPS") programs with incremental incentives designed to produce 100 MW of demand reductions by the summer of 2016, along with increased energy savings that would increase the likelihood of achieving the State's energy efficiency goals.[2] The April 19th Order (pp. 21-22) required that Con Edison and NYSERDA jointly file a revised plan, in consultation with NYPA that would expand or add specificity in the following areas:

1. The potential contribution of on-site baseload generation – CHP and distributed generation – beyond NYSERDA and NYPA CHP projects "in the pipeline";
2. The potential contribution of large customers in Con Edison's electric service territory who may be practically capable of switching from electric to steam-driven chillers;
3. Prioritization and segmentation of the markets for efficiency, load management and demand response, including which building types and other facilities Con Edison and NYSERDA intend to pursue aggressively and why;

[2] Case 12-E-0503, *Compliance Filing of Consolidated Edison Company of New York, Inc. and New York Power Authority with Respect to Development of Indian Point Contingency Plan*, February 1, 2013.

4. How many megawatts can be secured from what resource category at given cost/MW levels to make informed decisions on program targets budget, as well as the proposed source and nature of any required financial incentive;
5. The proposed means to discipline and minimize the level of project support required, including how the plan would limit financial support to projects that otherwise would not come online in a timely fashion and limit incentives to less than 100% of project costs; and
6. How the Revised Plan will build on and be integrated with existing programs like EEPS, Technology and Market Development ("T&MD") and the Renewable Portfolio Standard ("RPS").

The April 19th Order (pp. 22, 25) originally required that the Organizations file the Revised Plan within 45 days of the date of the April 19th Order. On May 31, 2013, Acting Secretary Cohen granted an extension of the filing date to June 19, 2013.

As directed by the Commission, Con Edison worked closely with both NYSERDA and NYPA and all the Organizations are jointly filing this Revised Plan for Commission approval. The Revised Plan builds on the Organizations' substantial and complementary experience in implementing a variety of clean energy and demand management programs including EEPS, Targeted Demand Side Management ("T-DSM"), Demand Response ("DR"), T&MD, Build Smart NY, and RPS. In this jointly-developed Revised Plan the Organizations have built upon their diverse experience in clean energy markets to share information, improve communication and confront challenges. The Organizations anticipate that these efforts and their joint implementation of the Revised Plan will enable customer participation and implementation of demand management solutions including energy efficiency, DR and CHP.

II. THE REVISED PLAN

The Revised Plan includes a joint program, to be implemented by Con Edison and NYSERDA, with support from NYPA that is designed to achieve 100 MW of cost-effective peak demand reduction in the Con Edison service territory by the summer of 2016. The 100 MW demand reduction will be coincident with the system peak expected to occur during the summer capability period,[3] and will be in addition to peak demand reductions that are currently planned for in the NYISO's RNA. The Revised Plan also includes a 25 MW CHP program to be administered by NYSERDA, and NYPA's plan to save an additional 15 MW through the Build Smart NY program.

A. **The IPEC Program**

The Indian Point Energy Center ("IPEC") Program is a joint program designed to achieve 100 MW of peak reduction by offering a peak-kW incentive targeting customer energy use that is coincident with the system peak. The incentive will be in addition to existing incentives for other demand management programs and is planned to include a bonus for large projects and project aggregations by large customers. Since the goal of the Revised Plan is to produce 100 MW of additional peak reduction by the summer system peak of 2016, the incentive will only be provided to projects verified by Con Edison or NYSERDA as having been completed during the period January 1, 2014 through May 31, 2016.

The IPEC Program will be funded by a uniform per kWh IPEC Reliability Surcharge imposed on all kWh delivered by Con Edison to its customers[4] exclusive of deliveries to NYPA's governmental customers under the Company's Schedule for PASNY Delivery Service

[3] For purposes of the Revised Plan, the system peak demand period is comprised of the hours between 12:00 pm and 6:00 pm on non-holiday weekdays during the period May 1 through October 31.
[4] As with funding for the Company's existing DR and T-DSM programs, the IPEC Reliability Surcharge will be collected through the Monthly Adjustment Clause ("MAC").

(PSC No. 12 - Electricity), who already participate in the NYPA Build Smart NY Program that will contribute to the IPEC Revised Plan goals. The IPEC Program incentive will be available to any electric customer within the Con Edison service territory that pays the IPEC Reliability Surcharge.

Con Edison and NYSERDA will share a goal of achieving the 100 MW peak reduction and will jointly implement the IPEC Program utilizing a single point of entry for all participants in order to achieve that goal. Marketing materials and offerings for the IPEC Program will include both Con Edison and NYSERDA logos and the IPEC Program will have a single application process for the peak kW customer incentive. As part of this effort, Con Edison and NYSERDA will develop a consistent measurement and verification ("M&V") protocol for customer peak demand reductions.

In order to achieve the IPEC Program's goal of a 100 MW of peak reduction by the summer of 2016, the program will necessarily focus its recruiting on Con Edison's large commercial and industrial ("C&I") customers, and will build upon Con Edison's and NYSERDA's existing EEPS C&I programs. However, the current overlap of programs, with unequal incentives and different designs and requirements across programs, could complicate achievement of the 100 MW peak reduction. For this reason, Con Edison and NYSERDA have an interest in pursuing solutions that are oriented to the market (*i.e.*, customers and contractors) and that allow their respective C&I programs to function in a complementary way. In order to provide a seamless and efficient IPEC Program, the incentives and program rules of the C&I programs should be made uniform for both EEPS kWh and IPEC Program kW incentives. Additionally, the existing programs should be made more efficient by removing the administrative burdens for allocating budgets between programs, easing the customer payback criteria, and reconsidering the appropriate application level(s) of the Total Resource Cost test applied to EEPS programs. Con Edison and NYSERDA believe that these solutions are critical initial steps to support complementary program design. Further program alignment, including a joint MWh goal, has been discussed as a potential approach to orient programs to the market and to streamline overall program delivery, reporting, participation and implementation. Con Edison and NYSERDA see potential in further and more detailed discussion on a joint MWh goal pending the Commission's directive to implement the IPEC Program.

1. Joint Sales, Outreach and Marketing and Project Management Strategy

Con Edison and NYSERDA will work together as one team, presenting one program to customers, in order to achieve the IPEC Program goal. To support this effort, Con Edison and NYSERDA will maintain a single point of customer entry into the IPEC Program and a consistent process for sales, project management, outreach and marketing. Sales will be achieved through a joint sales approach administered by Con Edison and NYSERDA.

As is currently the case with the data center program,[5] Con Edison and NYSERDA will conduct weekly status meetings to review lead assignments, report on the status of projects, address any issues that may come up, discuss general program matters, and share market intelligence. Regularly scheduled marketing meetings will be held with participation from the appropriate representatives of Con Edison and NYSERDA. Con Edison and NYSERDA have already begun joint discussions regarding the development of program marketing materials, banners, webinar presentations, and media and advertising campaigns.

[5] The Data Center Program is a NYSERDA and Con Edison collaboration to help data centers reduce energy use, save on operating costs, and cut greenhouse gas emissions through more efficient use of electricity. Con Edison and NYSERDA work together to provide data center operators in Con Edison's service territory with targeted technical assistance and financial incentives to support energy efficiency. The collaboration has successfully helped customers reach energy goals and intelligently manage their electric load.

The IPEC Program will be promoted through coordinated outreach and marketing that leverages the complementary strengths and experiences of NYSERDA and Con Edison to deliver an integrated, co-branded solution that will be jointly administered. The IPEC Program outreach and marketing program will dovetail with the existing efforts of both parties to maximize customer engagement and deliver incremental program value through a single program entry point and messaging.

NYPA will support these efforts for NYPA Recharge NY customers. These customers are eligible to participate in the IPEC Program based on their contribution to the IPEC Reliability Surcharge.

2. Joint Performance Reporting

Con Edison and NYSERDA will maintain a robust and detailed accounting of IPEC Program details in order to: 1) provide feedback on program performance; 2) allow for geographical performance data to be used for electric distribution system planning; and 3) facilitate consistent and accurate reporting to regulators and stakeholders. For the reporting process to be effective, both Con Edison and NYSERDA will share or provide to the other organization immediate access to project-level performance details, including, but not limited to: location of project, measure-level impacts on peak demand, total size of incentive issued, and time of completion. Con Edison and NYSERDA recognize that their data and reporting systems may need to be aligned so that project level details can be co-filed and reviewed by Con Edison and NYSERDA and provided to Department of Public Service staff.

3. Customer Incentives

In its April 19th Order (p. 21), the Commission stated that it shares the concerns of several parties about the significant costs of the program set forth in the Initial Plan, and directed that the

Revised Plan propose the "means to discipline and minimize the level of project support required." To address that concern, and as is explained below, Con Edison and NYSERDA will adhere to the following four principles of price discipline in setting the IPEC Program incentives: Cost-effectiveness will be tested at the program level for hours of peak impact to determine whether the total IPEC Program will be cost effective. The cost of the IPEC Program will be measured against the benefits of avoided energy, avoided line loss, avoided generation capacity, avoided environmental impacts, and avoided transmission and distribution infrastructure capital expenditures.

1. Incentive offerings will be available for a limited time only, and subsequent offerings may be extended at a different price to reflect current market conditions and the extent to which the IPEC Program goal has been achieved.
2. The incentive design will be established based on the diverse and extensive program experience of both Con Edison and NYSERDA and will require meaningful customer cost-sharing.[6]
3. Incentives will be adjusted in response to evolving market forces, providing the ability to reduce ratepayer costs.
4. Marketing and outreach will focus on reaching customers and reducing peak demand in networks that are under load constraints during times of system peak, which will help to reduce or defer the long term costs of operating utility distribution infrastructure.

Con Edison has the responsibility to provide reliable service to its customers and achieving the IPEC Program goal will necessarily require an incentive that is significant enough to spur

[6] As described elsewhere in the Filing, cost share for participants represents approximately half of total project costs.

aggressive demand reduction activities that would not otherwise occur. Moreover, the short time frame for projects to be completed, installed, and verified for performance necessitates providing Con Edison and NYSERDA with the flexibility to adjust the incentive as necessary to respond on a near real-time basis to evolving market conditions and the extent to which the IPEC Program goal is being achieved. For that reason, Con Edison and NYSERDA are proposing a customer incentive that will elicit 100 MW of peak-kW reductions, with graduated bonuses for projects that deliver substantial peak demand savings greater than 500 kW,[7] and with the flexibility to adjust incentives as necessary.

4. Integration with Existing Programs

The April 19th Order (p.22) states that the Revised Plan must provide further detail on how it will build on or be integrated with existing programs like EEPS, T&MD and RPS.[8] Con Edison and NYSERDA intend to market the IPEC Program incentives by building upon and expanding the existing EEPS program implementation platforms (including implementation contractors, market partners, and existing leads) with the goal of minimizing operational disruption of the existing platform while expediting program rollout and participation in the IPEC Program. The ability to use the existing EEPS infrastructure will facilitate a rapid start up once regulatory approval and funding is secured.

Through aggressive marketing of the per-kW incentive, Con Edison and NYSERDA anticipate substantially greater interest in existing EEPS measures such as replacement of

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[7] For example, if a 0.5 MW load reduction were achieved, the customer could receive a cash bonus to be determined by Con Edison and NYSERDA, for 1 MW reduced the bonus would be increased to an agreed upon amount, for 2 MW reduced the bonus would be increased further, and so forth for each MW of demand reduction achieved up to a maximum amount to be determined.

[8] Con Edison and NYSERDA evaluated including customer-sited renewables in the Revised Plan. However, it was determined that further discussion is required to understand and assess the technical capabilities, performance characteristics, and economic impacts on customers and developers before RPS eligible renewable can be included in the Revised Plan.

existing and end-of-life equipment with more efficient alternatives, particularly heating, ventilation and air-conditioning ("HVAC"), interior lighting and building management systems. In addition, the IPEC Program is expected to drive larger projects with potentially deeper kWh and kW savings through measures that are currently ineligible under EEPS.

To the extent that energy efficiency measures such as interior lighting and HVAC replacements may achieve deeper penetration within EEPS projects due to the additional peak-kW incentives offered through the IPEC Program, those kWh savings would be allocated towards existing EEPS goals. Importantly, those savings will more likely be obtained during the limited time available to achieve the 15x15 goal, since the time-limited availability of the peak-kW incentives should spur quicker installation of measures.

Con Edison and NYSERDA will develop an M&V process that will verify peak kW reductions resulting from the IPEC Program and will be designed to avoid duplicate or repetitive M&V processes per project to avoid customer delays and the waste of ratepayer money.

5. Customer Participation

The April 19th Order (p. 21) states that the Revised Plan must provide more detail on which building types (*e.g.*, owner-occupied buildings, Class B office buildings) and other facilities Con Edison and NYSERDA intend to pursue aggressively and why.

Con Edison and NYSERDA will target the following specific customer groups[9] that are most likely to offer the opportunity for significant peak demand reductions before the summer of 2016:

[9] In addition to the primary customer types identified above, there is also a collective potential for demand reduction among HVAC used by residential and small to medium businesses and institutions. The collective load reduction potential among these customers is significant, and should not be overlooked simply because they have relatively low individual demand.

- Located within the Con Edison Service territory – The IPEC Program will be available to all delivery customers within the scope of this project exclusive of deliveries to NYPA's governmental customers under the Company's Schedule for PASNY Delivery Service (PSC No. 12 - Electricity), who already participate in the NYPA Build Smart NY that contributes to the IPEC Program goals.[10]
- High Peak Demand - Marketing and outreach will focus on attracting customers with high peak demand and project developers with potential large scale projects at one or more locations. The IPEC Program will be designed to include solutions for large building owners and large customers of all building types. The IPEC Program will also address portfolios of multiple locations and chain accounts that aggregate to large demand.[11]
- Prior/Existing EEPS Participants - Customers who are currently planning EEPS projects, or who have already conducted small projects under EEPS, may be willing to expand the scope and depth of projects under the new incentive structure.
- Fuel Switching - Customers capable of fuel switching for summer air conditioning load (*e.g.*, electric to steam or electric to gas) represent high potential for either directly reducing peak load or preventing migration to the electric system. This opportunity includes customers willing to operate a hybrid chiller system,[12] which

[10] Includes NYPA Recharge NY customers who are eligible to participate based on their contribution to the IPEC Reliability Surcharge.
[11] Irrespective of whether the IPEC is closed, reducing the demand of large customers located within an existing or future Targeted Demand Side Management network provides significant value. The same is true for customers with poor load factors that achieve their highest demand peak during times of system peak.
[12] These customers would need to demonstrate or assure that the chiller is operating on steam during peak load times.

may include customers willing to install steam equipment using the Company's steam service.

6. Program Measures

Only those measures that reduce metered peak demand will be considered eligible for the peak-kW customer incentive. Accordingly, additional project or measure-level demand reductions occurring outside the window of system peak will not be eligible for the peak-kW incentive.

Con Edison and NYSERDA have experience using performance incentives to implement load shifting strategies by building operators. Performance incentives may be used to encourage 1) periodic or regular maintenance and 2) continuous commissioning of equipment and building management systems by trained operators.[13] Further, incentives would be available to facilitate training for operators.

Con Edison and NYSERDA will also consider the use of block bidding as a means to engage energy service companies and Original Equipment Manufacturers to accelerate acceptance of new technologies. This approach could support more broad and deep market engagement, aggregated load reduction projects, targeted technology or market segments. Block bidding could also provide a vehicle for cost containment by using a request for proposal ("RFP") process to solicit block bids that focus on key market segments or measure types that have large potential savings, but have for one reason or another not participated in the programs as otherwise would have been expected. Block bidding is designed to build upon the solid foundation already established by existing Con Edison and NYSERDA C&I programs and Con Edison's T-DSM

[13] A building management system is defined as a controls system that has the capacity to collect data, interpret the information and then take action. In addition to the basic functionality of equipment scheduling and alarm notification, it should enable the components of a cooling system to interact with each other to operate optimally by meeting cooling load demand with minimal energy usage.

without taking customers from those programs.[14] Any use of block bidding would be carefully designed to minimize disruption to existing EEPS programs.

7. Expected Load Reduction Contributions

Demand reduction opportunities fall into three categories of customer-sited measures: permanent load reduction, load management, and fuel switching. First, permanent reductions in peak load will be obtained through replacement of existing and end of life equipment with more efficient alternatives. These are the measures most likely to have existing incentives in place through existing EEPS programs. Only the impact on peak load reduction will be taken into account for calculation of the peak-kW reduction incentive.[15]

Second, by utilizing energy management systems, thermal energy storage, or battery arrays, customers can manage their load and remove kW from the system peak by transferring load to off-peak hours. Customer energy management has significant potential for not only removing MW from the system peak, but also for reducing the costs of operating the distribution system. As discussed in the previous section, performance contracting represents an opportunity for load management strategies so that long-term operations result in continued load reductions.

Third, fuel switching from electric cooling to steam or gas cooling directly removes peak MW from the electric system. The existing Targeted Steam AC Program, part of the T-DSM Program, requires that a chiller replacement project be located within one of the designated electric "targeted" networks. Expansion of the program to all of the electric networks would provide additional electric system benefits and provide customers with economically competitive cooling equipment alternatives. Alternatively, an equivalent amount of electric load relief can be

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[14] Bidding would necessitate certain requirements for financial security or related mechanisms among the bidders to ensure performance

[15] As stated the Initial Plan, measures whose primary impact is exhibited during times of non-peak load conditions such as outdoor lighting and variable frequency drives will not be eligible for the peak kW incentive

obtained by utilizing a qualifying gas-fired chiller or absorber in lieu of the steam-powered equipment required as part of the Targeted Steam AC Program. Accordingly, the IPEC Program would supplement the current T-DSM Program by including incentives for both types of non-electric cooling equipment. By doing this, the IPEC would expand non-electric cooling incentives beyond the steam service territory and would be applicable to a larger customer base. This option would also provide customers with more options to meet their cooling requirements.

While some customers may elect to install only one of the above measure types, an operational goal of the program will be to encourage as many customer facilities as practical to install two or more measures. For instance, energy saving measures, when coupled with a comprehensive load management and energy storage system for a large building, or coupled with fuel switching, or both, can yield large peak reductions up to or even exceeding 500 kW. By encouraging large projects, the program aims to achieve cost savings through economies of scale, reducing the overall burden of recruiting and managing hundreds of small projects, while expediting the implementation of demand reductions by the summer of 2016. For this reason, and as described in greater detail below, awarding an additional incentive for projects that achieve a significant scale of demand reduction (*e.g.*, 500 kW or greater) would be beneficial to the IPEC Program.

8. Cost Estimates

The April 19th Order requires (p. 21) that the Revised Plan "include an integrated, fully justified 'supply cost curve' for acquiring peak reduction MW from efficiency, demand response, load management, on-site base load generation and fuel switching." The estimated costs of the IPEC Program measures are necessarily subject to further analysis, but the following presents the

Organizations' current estimate of the costs of the types of different measures that will be included in the IPEC Program.

a. Explanation of Cost Estimation Methodology

Con Edison and NYSERDA worked together to analyze legacy energy program activity and to utilize internal and industry partner expertise as sources for a robust cost analysis. This information was used as a basis for estimates of total project costs and incentives necessary to attract participation and influence project development in order to deliver the proposed 100 MW of peak demand reduction.

In addition, Con Edison and NYSERDA assembled and analyzed a substantial data set of existing projects - representing over 80 MW of peak demand reduction. This data set was assessed from the perspective of energy (kWh) savings, peak-demand (kW) savings, total project cost and incentives to the extent available for a particular load reduction strategy.

Market participants and subject matter experts were also consulted as additional sources for cost and performance information. This approach allowed Con Edison and NYSERDA to analyze data from multiple sources with special emphasis on the load management strategies that integrate energy storage (thermal and battery-based) and non-electric (natural gas and steam) air conditioning systems. Vendor prices were used to develop a comparison of equipment cost for various types of non-electric chillers. Information was collected on thermal storage costs and market potential from the developers of thermal storage installations in New York City as well as engineering professionals with relevant project experience. Estimates from market stakeholders were consistent with the average cost of thermal storage calculated from previous load management projects.

This data formed the basis of the estimates for incentives necessary to secure timely market attention and project completions though accelerated implementation of strategies that include permanent demand reduction, fuel switching, and load management strategies – as further described below.

b. Measures Evaluated for the IPEC Program

Permanent demand reduction - High efficiency electric chillers and light-emitting diode ("LED") lighting are measures currently offered in existing EEPS programs. Based on a recent study by Global Energy Partners, LLC[16] these measures have been identified as having a high market potential as well as a high potential for peak kW reduction. In addition to lighting and comprehensive cooling projects, the Organizations see broader opportunities for permanent demand reduction including controls and process upgrades at facilities such as datacenters and water treatment plants. The IPEC Program will pay for kW reduced for the installation of these measures on top of existing EEPS incentives. These technologies have proven their effectiveness in reducing demand. The additional incentive from the IPEC Program will increase the rate of replacement of old inefficient chillers and old lighting systems with new high efficient technologies.

Load management - Load management measures included in the cost estimation are energy storage (thermal or battery), building management systems ("BMS") and automated demand response ("AutoDR").[17] These technologies have made great strides in the last few

[16] I. Rohmund and G. Wikler, Global Energy Partners, *Energy Efficiency Potential Study for Consolidated Edison Company of New York, Inc., Volume 2: Electric Potential Report, Final Report*. March 2010. Available online: http://www.coned.com/documents/Volume_2_Executive_Summary.pdf

[17] For the purpose of this filing and the IPEC Program a BMS is defined as a controls system that has the capacity to collect data, interpret the information and then take action. In addition to the basic functionality of equipment scheduling and alarm notification, it should enable the components of a cooling system to interact with each other to operate optimally by meeting cooling load demand with minimal energy usage.

years and are now dependable resources for reducing peak demand. AutoDR equipped lighting controls (LED & fluorescent), window air-conditioners and packaged terminal air-conditioning units can provide strategic short term load curtailment. Thermal storage essentially stores thermal energy by making ice at night with electric chillers and then releasing the thermal energy to cool the building during the day when demand is greater on the system. Thermal cooling technology can be used for demand management at the individual customer level as well as for district cooling at a complex multi-building application or for process cooling. Energy storage is also a viable alternative for peak reduction if the battery or other energy storage system has to reduce the committed load for a six-hour duration. BMS is currently incentivized in existing EEPS programs; the IPEC Program will pay for kW reduced on top of existing incentives paid in order to encourage BMS installations and upgrades at a faster rate.

Fuel Switching; Steam or Gas – The existing Targeted Steam AC Program requires that a chiller replacement project be located within one of the designated electric "targeted" networks. The IPEC Program will incentivize steam customers outside of the targeted networks to convert their electric chillers to high efficiency steam or gas chillers. Incentives will also be offered to steam customers to discourage them from switching to an electric chiller. Those customers with an end of life steam chiller may currently opt to convert to electric chillers which contribute to load increases on the electric system. To avoid such conversions, the IPEC Program will also incentivize customers with existing steam chillers to upgrade to a new high efficiency steam chiller.[18]

[18] Steam turbine chillers are similar to electric chillers, in that they use traditional refrigerants and have a standard refrigeration cycle. The main difference is that steam turbine chillers utilize a turbine in lieu of a motor to turn the compressor. Another type of steam chiller the IPEC Program will incentivize is the double stage absorption chiller. This type of chiller utilizes a lithium bromide solution in an absorption refrigeration cycle. The refrigeration cycle is similar to the traditional cycle but has a generator in lieu of a compressor as well as an absorption section.

c. Estimated Total Cost of the IPEC Program

The IPEC Program budget is composed of customer incentives, plus planned costs for outreach, marketing, technical support, measurement and verification, administration, reporting and evaluation. Con Edison and NYSERDA expect that incentives representing a reasonable, minimum project cost share (*e.g.,* approximately accounting for half of project costs) will be a prime driver for the amplified activity necessary to reach the 100 MW goal. This will result in projects that include meaningful participant investment or project cost-share as a means to contain ratepayer costs supporting the program. In no case will the combined incentives paid through EEPS and IPEC exceed 100% of the project cost.

Con Edison and NYSERDA will closely monitor rates of program participation and progress in achieving load reductions and will revisit the incentive levels and project cost share approaches with the intent of increasing participant cost share as meaningful progress is demonstrated. Other steps to assure that estimated costs are reasonable and contained include a review by NYPA, in addition to the Con Edison and NYSERDA review, and input from market experts. Opportunities have been discussed and will continue to be sought to build on and leverage the IPEC Program with existing EEPS program platforms and customer and contractor relationships, including joint outreach, sales and marketing.

The information and process described above provide the foundation for incentives, outreach, marketing, measurement and verification, and administration and other anticipated program costs to achieve 100 MW of peak demand reduction by summer 2016. Based on market forecast estimates, this corresponds to a proposed full program budget of $220 million. As identified in Table 1 below, this cost includes the cost of incentivizing customers within the major measure categories discussed above, as well as technical support, operator training, performance incentives, and program management costs (incl. marketing, administration, M&V, and reporting).

Table 1: IPEC MW Reduction Market Forecast and Proposed Program Budget

	Total IPEC Market Forecast MW	**IPEC Budget (in millions)**
Load Management	44	$77
Permanent Demand Reduction	40	$54
Fuel Switching	16	$15
Technical Support (including facility operator training & performance incentive)		$15
Program Management Costs		$58
Target IP Demand Reduction Budget	100	$219

9. Cost-Effectiveness

Con Edison and NYSERDA anticipate that an incremental program to reduce peak demand must be separate from the EEPS program from a regulatory policy perspective and guided by the following benefit cost test at the program level:[19]

$$\frac{Benefit}{Cost} = \frac{NPV(\mathrm{Energy} + \mathrm{LineLoss} + \mathrm{Capacity} + \mathrm{Environmental} + \mathrm{T} + \mathrm{D})}{NPV(\mathrm{UtilityCosts} + \mathrm{CustomerCosts} + \mathrm{ProgramAdmin})}$$

The test will be applied at the IPEC Program level and will evaluate the benefits of the program for operations during hours of peak demand. Utilizing the best available projections for capacity, energy pricing, environmental impacts, and distribution costs yields a Benefit/Cost

[19] CHP and DR costs and benefits have been developed by NYSERDA to estimate levelized $/MWh and $/MW respectively.

ratio of 1.0. These projections are based upon IPEC remaining in service and all future cost projections assume the plant will remain in service through the foreseeable future. Should IPEC close, however, the cost of generation capacity and energy prices could increase significantly, making the IPEC Program far more cost effective.[20] Accordingly, it is notable that the IPEC Program is cost effective under current market conditions.

The IPEC Program's demand reduction target of 100 MW is based on Con Edison's and NYSERDA's best understanding of realistic achievable market potential within the short program window. Specifically, the 100 MW target is primarily based on the market potential for large projects to complete energy management solutions to remove on-peak demand. These projects take significant time to plan for and arrange for budgeting or financing. Accordingly, due to the short time before the contingency need (less than 5 years away), it is not realistic to plan for any additional MW reductions that could be achievable through this program. Alternatively, a smaller program target of less than 100 MW would not save an equivalent amount in program costs (*e.g.* $2.2 million per MW). Certain upfront costs in staffing, program administration, marketing, and outreach will not decrease proportionally to a decrease in MW reductions. A reduction in program goals might therefore result in a more expensive acquisition cost (*e.g.* greater than $2.2 million per MW) and a less cost effective program then what is described in this filing.

10. Source of Funding

The April 19th Order (p. 21) requires that the Revised Plan "propose the source and nature of any required financial incentive." Con Edison and NYSERDA propose that Con

[20] The cost of energy used in the benefit/cost test was based on the 2012 average weekday afternoon wholesale price of energy in NYISO Zones J & I. This period had an abnormally low cost of peak energy, as excess natural gas capacity kept fuel prices at historically low levels.

Edison delivery customers will pay a surcharge to cover the cost of the IPEC Program, on an arrears basis (after the costs have been incurred), through the MAC charge as is done for the DR and T-DSM programs, exclusive of NYPA's governmental customers who receive delivery service under the Company's PSC No. 12 -- Electricity.

Finally, Con Edison will not seek a shareholder incentive for the implementation of the IPEC Program.

B. NYSERDA CHP Program

1. Introduction

NYSERDA will administer the CHP portion of the IPEC Program. This will consist of an expansion of the existing T&MD CHP Acceleration Program, and is hereinafter referred to as the Expanded CHP Acceleration Program.

2. CHP Program Goals and Customer Incentive

The Expanded CHP Acceleration Program will achieve 25 MW of peak load reduction via CHP, all to be operational by Summer 2016, and will be administered with the existing T&MD $1,600/kW portfolio-average incentive rate of direct incentives to customers (thus, 25 MW at $1,600/kW would represent $40 million of direct incentives to customers). In addition, as further described below, additional costs will be incurred to support the activities of technical assistance contractors and outreach contractors, as well as NYSERDA administrative costs (such as NYSERDA staff salaries and benefits, Measurement & Verification, NYS Cost Recovery Fee, etc), resulting in a total cost to the ratepayers of $66 million (thus $66 million delivering 25 MW represents $2,640/kW for the "all-in" ratepayer cost).

3. Measure Characteristics to Incentivize

The Expanded CHP Acceleration Program will support the installation of CHP systems in the size range of 50 kW to 1.3 MW using vetted equipment which has been admitted into the program's catalog.

4. Expected Load Reduction Contributions

Load reductions will occur throughout the May-October peak demand period in the amount of 25 MW. The CHP projects funded by the Expanded CHP Acceleration Program will be designed to operate during these peak hours, and all projects must demonstrate to NYSERDA that operation throughout these peak hours is in the financial best interests of the project proponent. For example, the project proponent may demonstrate that the tariff which will apply provides a clear economic signal that impels operation of the CHP system throughout these peak hours, and that failure to operate throughout these peak hours would cause a financial penalty attributable to the tariff. The MW accomplishments to be claimed by the program will consist of that fraction of the CHP system demonstrating to NYSERDA that operation throughout these peak hours is in the financial best interests of the project proponent, plus that additional fraction of the CHP system confirmed to be enrolled in a demand response program, and will total 25 MW.

5. CHP Program Operations

NYSERDA will administer the Expanded CHP Acceleration Program to deliver energy savings and permanent peak-demand savings via CHP (such reduction in peak demand will occur when customer-self-generated electricity is substituted for a fraction of what the customer would otherwise consume and demand from the grid), consisting of customer-sited generators operating on natural gas to produce both electricity and useful thermal energy in a clean and efficient manner, as further described below.

The Expanded CHP Acceleration Program will utilize an expansion of the existing catalog of pre-qualified equipment which is eligible for the program's incentives. Based on vendor submittals received, it is expected that the catalog will be further expanded to include a suite of steam backpressure turbines across a range of sizes within the program's 50 kW to 1.3 MW limits.

In addition to these activities via the IPEC contingency funding for CHP, NYSERDA has also requested federal Sandy Relief funds to install CHP throughout the 17-county affected area (much of such territory overlaps with the IPEC territory). Therefore, if the federal funds do indeed materialize, any CHP thus federally-funded and located within the IPEC zone will be counted towards timely achievement of the above-enumerated goal (and, at the discretion of the Commission, after thereby achieving the above-enumerated goal, the uncommitted IPEC funds could either be used to deliver additional CHP which would be installed at some eventual date, or as otherwise directed).

6. Integration with Existing CHP Programs

The existing T&MD CHP program consists of two formats (the CHP Acceleration Program, also known as the "Catalog" program, supports pre-qualified pre-engineered CHP modules in the size range 50 kW to 1.3 MW, while the CHP Performance Program supports custom-engineered CHP systems larger than 1.3 MW). The approved T&MD CHP funds, totaling $75 million, consist of $25 million dedicated to the CHP Acceleration Program, and $50 million dedicated to the CHP Performance Program, as further described below.

The existing CHP Acceleration Program has issued a statewide solicitation (PON 2568) which makes available $20 million of the $25 million in the form of direct customer incentives (the remaining $5 million will be used for other marketplace assistance activities, including but not limited to collection and posting of system performance data, re-commissioning activities at installation sites, technical assistance contractors for review of modules seeking admittance to the Catalog, technical assistance contractors for assisting host sites with evaluating prospectuses from various equipment vendors, conferences and other outreach activities, and the like). The CHP Performance Program has issued a statewide solicitation (PON 2701) which makes available $40 million of the $50 million in the form of direct customer incentives (the remaining $10 million will similarly be used for other marketplace assistance activities). Thus, $60 million of the $75 million T&MD funds are available as direct incentives to eligible customers.

The T&MD CHP program is expected to achieve 37.5 MW of peak load reduction via CHP installations (12.5 MW via the CHP Acceleration Program, plus 25 MW via the CHP Performance Program) to become operational in accordance with target dates as specified in the approved T&MD Operating Plan (not all of this is expected to occur in Con Edison territory, and not all of this is expected to be operational by Summer 2016). Thus, the portfolio-average incentive rate of direct incentives to customers is $1,600/kW ($60 million/37.5 MW). The proposed 25 MW of CHP for IPEC is above and beyond what current funding (SBC3, and SBC4/T&MD) is expected to otherwise deliver by Summer 2016, i.e., NYSERDA-funded projects in the pipeline that are expected to occur by the critical time and not already reflected in the RNA.

7. NYSERDA would initially target specific Customer types for participation in the Expanded CHP Acceleration Program

In addition to promoting uptake of all items in the Catalog, the Expanded CHP Acceleration Program will undertake a dedicated effort of outreach to the Con Edison steam customers, informing them of the opportunity to install a steam backpressure turbine "in parallel" with their steam inlet pressure reducing valves, so that the building could use the backpressure turbine to achieve pressure reduction while generating electricity on-site (reduce the steam pressure from circa 100 psi in the street, to approximately 15 psi for distribution throughout the building). Incentives for installation of a backpressure steam turbine would be pro-rated to the electric production during the summer period, and thus, other improvements at the site which increase summer steam consumption (such as the installation of steam absorption chillers) would improve the economics of the backpressure turbine. Thus, Con Edison and NYSERDA will promote concurrent adoption of steam absorption chilling (through a jointly-administered program) and steam backpressure turbines (through the NYSERDA-administered Expanded CHP Acceleration Program). Although not the primary objective of the IPEC contingency planning effort, by virtue of these capital investments in modern steam-related equipment, this would provide a desirable co-benefit of reinforcing customers' long-term commitment to the Con Edison steam system.

8. Cost of Acquiring CHP Peak Reductions

NYSERDA is keying the costs of the Expanded CHP Acceleration Program primarily to the costs for CHP authorized recently by the Commission via the T&MD program. This information was used as a basis for estimates of project incentives necessary to attract participation and influence project development in order to deliver the proposed 25 MW of CHP. NYSERDA currently plans that such additional incentives will be administered in an identical manner, and thus deliver a signal to the marketplace that there is no advantage to waiting for the IPEC Program funds to become available, and thereby emphasize prompt participation in the program as currently funded via T&MD. Notwithstanding this intent, NYSERDA recognizes the need for any and all necessary flexibility and nimbleness to adjust the program in response to market conditions in order to establish and maintain the urgent momentum necessary to meet the intensive goal of the program. Additional costs, for technical assistance contractors and outreach contractors, have been developed to support these crucial activities which will supplement the direct-incentives aspect of the program.

The additional CHP activities herewith described, to be funded via $66 million of IPEC contingency plan funds to achieve an additional 25 MW of peak load reduction via CHP would represent $40 million of direct incentives to customers. The remaining $26 million will be used for other marketplace assistance activities, which would by necessity be more-intensive than similar activities originally planned under the T&MD program (of this $26 million, $16 would be used for Outreach and Technical Assistance Contractor activities, while $10 million would be used for administrative functions such as NYSERDA staff salaries and State Cost Recovery Fee and Program Evaluation tasks).[21] For the expanded portion of the program, $16 million will be allocated for Technical Assistance Contractors and Outreach Contractors, which represents a $6 million "adder" compared to the $10 million for Technical Assistance Contractors and under T&MD to support an equivalent amount (25 MW) of CHP – note that the T&MD CHP Acceleration Program does not utilize any Outreach Contractors, so this additional feature

[21] These administrative functions are budgeted at 8% for NYSERDA staff salaries and benefits, 2% for State Cost Recovery Fee, and 5% for Program Evaluation, totaling 15%. The computation is based on program costs ($40 million direct incentives plus 16 million Technical Assistance Contractors/Outreach Contractors = $56 million) as follows: $56 million divided by 85% = $66 million "all-in" ratepayer costs. Note that $66 million times 15% = $10 million and $56 million plus $10 million = $66 million.

accounts for the need for these proportionately-additional funds. This need to specifically establish Outreach Coordinators for the Expanded CHP Acceleration Program is due to the need to drive an additional batch of customers into the program above-and-beyond the customers expected to be attracted through the efforts of the CHP system vendors to the base T&MD program. Due to the urgency and compressed timeline, a dedicated Outreach effort is planned to consist of the following two components: (1) outreach and coaching of Con Edison Steam customers to consider steam backpressure turbine CHP, and (2) a "hear from CHP experts and meet the pre-qualified CHP equipment vendors" expo to occur at venues in numerous neighborhoods throughout New York City. These two new Outreach activities are crucial, will require "adder" funds, and are the preferred strategy to drive participation in the CHP program by helping the CHP vendors with customer acquisition challenges (as opposed to a strategy of further enhancing the direct incentive to customers). In order to meet the fast-paced timeline, it is expected that these additional megawatts of CHP installations will occur through an expansion of the CHP Acceleration Program.

The fully-loaded budget is composed of customer incentives, plus planned costs for outreach, marketing, technical support, measurement and verification, administration, reporting and evaluation important to effective management of the program. It is expected that these incentives, which have already been established under the T&MD program to represent a reasonable, minimum project cost share (approximately half or more to be invested by the customer), will be a prime driver, but will also rely on intensified outreach efforts to create an amplified activity necessary to reach the 25 MW goal. The continued use of meaningful participant investment, or project cost-share, will be a means to contain ratepayer costs supporting the program. If necessary, budget adjustments may occur to move funds between the incentive pool and the Technical Assistance Contractors/Outreach Contractors pool. For example, if the Outreach effort proves very effective early in the program and facilitates sufficient customer acquisition, but those customers materialize overwhelmingly on the smaller end of the CHP size spectrum, the $40 million budget for direct incentives to customers may not be sufficient to achieve the 25 MW goal[22] and thus a reallocation of funds out of the Technical Assistance Contractors/Outreach Contractors pool and into the direct incentives pool would be appropriate.

9. Source and nature of any required financial and Expanded CHP Acceleration Program costs

The information and process described above provide the foundation for incentives, outreach, marketing, measurement and verification and other anticipated program costs which corresponds to a proposed full budget of $66 million to be funded with IPEC Contingency Plan funds to expand the T&MD CHP Acceleration Program into the NYSERDA-administered Expanded CHP Acceleration Program to achieve an additional 25 MW of peak demand reduction by Summer 2016.

C. NYPA Build Smart NY Program

NYPA has been working with several New York City and State agencies to identify incremental demand reductions based on long term capital planning and expects to achieve an additional 15 MW of peak demand reductions not accounted for in the 2012 RNA (some projected achievements from Build Smart NY are already included in the 2012 RNA)."[23] State agencies and authorities are working to accelerate energy efficiency in State facilities,

[22] The CHP Acceleration Program, and hence the Expanded CHP Acceleration Program, is budgeted for a portfolio-average direct incentive to customers at $1,600/kW and, in order to capture the economies-of-scale, uses a sliding scale of baseline incentives ranging from 50 kW at $1,800/kW to 1.3 MW at $1,150/kW. Additionally, two bonuses are available either singly or jointly, consisting of a 10% bonus for systems installed at critical facility sites, and/or a 10% bonus for CHP systems installed within Con Edison's Targeted Zones.
[23] Note that this would be over and above the 100 MW targeted by the IPEC Program.

particularly in light of Governor Cuomo's recently issued Executive Order 88 which mandates a 20 percent energy use reduction by April 2020. Additionally, the incremental demand reductions include work associated with aeration and de-watering system upgrades at wastewater treatment plants in New York City as well new efficiency opportunities identified in master energy plans that are envisioned for university campuses in New York City. Equipment at many of the wastewater treatment plants has outlived its useful life and there has been significant advancement in the technology that can be employed to further reduce high level energy consumption at these facilities. Campus-wide ASHRAE Level II audits will help identify capital energy efficiency retrofits. In addition to energy efficiency measures, the audits will help to identify opportunities for cost effective on-site renewable generation and potential for CHP projects. All NYPA Energy Efficiency Program projects are funded through NYPA low cost financing which is recovered from the direct program participants.

CONCLUSION

For the reasons set forth above, Con Edison, NYSERDA and NYPA respectfully request that the Commission approve the Revised Plan and allow them to move forward with its implementation.

Dated: New York, NY
June 19, 2013

Respectfully submitted,

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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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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

[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

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[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]

[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

[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,

[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

[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

[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

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[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.

[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

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[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

[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.

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[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. Entergy

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. Commission Determination

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

[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,

(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.

<u>New York Energy Consumers Council, Inc.</u>:

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.

BEFORE THE STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion to Examine Alternating Current Transmission Upgrades	))	**Case 12-T-0502**

STATEMENT OF INTENT TO CONSTRUCT TRANSMISSION FACILITIES OF CENTRAL HUDSON GAS AND ELECTRIC CORPORATION, CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. / ORANGE & ROCKLAND UTILITIES, INC., NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID, NEW YORK STATE ELECTRIC & GAS CORPORATION / ROCHESTER GAS AND ELECTRIC CORPORATION, NEW YORK POWER AUTHORITY AND THE LONG ISLAND POWER AUTHORITY
ON BEHALF OF THE NEW YORK TRANSCO

Pursuant to the November 30, 2012 *Order Instituting Proceeding* ("Order"),[1] of the New York State Public Service Commission ("Commission"), Central Hudson Gas and Electric Corporation ("Central Hudson"), Consolidated Edison Company of New York, Inc. ("Con Edison") / Orange & Rockland Utilities, Inc. ("O&R"), Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"), New York State Electric & Gas Corporation ("NYSEG") / Rochester Gas and Electric Corporation ("RG&E"), New York Power Authority ("NYPA") and the Long Island Power Authority ("LIPA")[2] (collectively, the "New York Transmission Owners" or "NYTOs") hereby submit this Statement of Intent on behalf of the New York Transmission

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[1] Case 12-T-0502, *Proceeding on Motion to Examine Alternating Current Transmission Upgrades*.

[2] Continued participation of Long Island Power Authority in New York Transco is contingent on (i) the continuation of LIPA in its current form or its ability to assign its New York Transco rights and obligations to a successor organization; (ii) a determination that the projects contemplated to be undertaken by the NY Transco benefit LIPA's ratepayers when considering LIPA's costs, public policy goals and reliability considerations, and (iii) the enactment of legislation that enables LIPA to participate in the New York Transco.

Company ("New York Transco" or the "NY Transco") to construct alternating current ("AC") transmission facilities.

I. EXECUTIVE SUMMARY

In response to the Commission's Order, the NYTOs on behalf of the NY Transco hereby submit this Statement of Intent to construct five new AC transmission projects (the "Projects"):

1. Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring;
2. Second Ramapo to Rock Tavern 345 kV Line;
3. UPNY/SENY Interface Upgrade;
4. Second Oakdale to Fraser 345 kV Line; and
5. Marcy to New Scotland 345 kV Line.

These Projects are being proposed in order to accomplish the goals and objectives of the Commission's Order, which are to increase transfer capability through the Central East and UPNY/SENY interfaces[3] and to "meet the objectives of the Energy Highway Blueprint."[4] As shown herein, these Projects will significantly reduce constraints over key transmission interfaces and provide the public policy benefits specified in the *New York Energy Highway Blueprint* ("Blueprint").[5] To build these and other transmission assets in New York State, the NYTOs are forming a unique public-private partnership by creating a new statewide transmission entity, the New York Transco. The NY Transco will pursue the planning, development, construction,[6] and ownership of new transmission projects that will enhance the current capabilities of the bulk power system across New York State. This new business structure, in conjunction with Governor Cuomo's Energy Highway Blueprint and the Federal

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[3] Order, p. 2.
[4] Id.
[5] A copy of the Blueprint can be found at: http://www.nyenergyhighway.com/PDFs/Blueprint/EHBPPT/.
[6] Project construction will be completed in accordance with all standards, specifications, practices, and procedures of the host NYTO.

Energy Regulatory Commission's ("FERC") Order 1000,[7] permits and encourages continued investment in the state's transmission infrastructure to improve statewide reliability and provide cost-effective infrastructure improvements to benefit all New Yorkers.[8]

As shown herein, the overall investment of approximately $1.3 billion in these Projects will stimulate the creation of an estimated 6,000 direct jobs and nearly 17,000 total jobs. It is estimated that on an annual basis the Projects will result in approximately $176 million in statewide production cost savings. In addition these projects offer a reduction in annual Installed Capacity ("ICAP") costs estimated in the range of $50 million to $200 million, which could vary year to year. An important benefit of this proposal is the positive environmental impact that these Projects will bring to New York State. To fully meet the state's objectives, as explained in the Order and the Blueprint, requires an extensive amount of transmission build-out. As explained herein, the Projects for the most part are upgrades of or additions to existing transmission facilities. As such, the Projects will impact only approximately two square miles of land not currently occupied by transmission facilities and most, if not all, of this land will be adjacent to existing utility corridors. Because the NY Transco will be able to leverage the rights-of-way ("ROW") assets of the NYTOs, the impact of the transmission additions is minimized.

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[7] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 36 FERC ¶ 61,051 (July 21, 2011) ("Order 1000").

[8] While the Projects have been initiated and will continue to progress until a commitment of significant funding is required, individual NYTO, affiliate and/or parent organization approvals and several governmental approvals are necessary to advance these Projects to completion. The governmental approvals include: (1) Commission approval of the cost recovery mechanism and endorsement of the cost allocation mechanism specified in this filing; (2) enactment of legislation to enable NYPA and LIPA to participate in the NY Transco as full equity owners; (3) Federal Energy Regulatory Commission ("FERC") approval of the NY Transco formula rate; (4) Commission approval of the ability of each of the NYTOs to recover the costs of the NY Transco Projects from their retail ratepayers; (5) Commission approval of the recovery by an NYTO of its replacement-in-kind ("RIK") costs from its retail customers; and (6) the additional Commission authorizations specified in this filing.

Further, the Projects will allow for a large reduction in CO_2 and NO_X emissions annually, equal to approximately 227,000 tons and 83 tons, respectively by allowing more efficient generation to be dispatched across the state. An additional benefit is that these Projects can be developed relatively quickly with most being able to be in service between 2016 and 2018.

The Projects are supported by the analysis documented in the New York State Transmission Assessment and Reliability Study ("STARS") that was performed by the NYTOs with assistance from the New York Independent System Operator ("NYISO") and input from stakeholders. The STARS Phase II report, which was issued on April 30, 2012, analyzed the long-term needs of the state's transmission system beyond the immediate 10-year horizon typically studied by the NYISO.[9] STARS also analyzed the state's bulk power system to identify the system replacement needs over a 30-year period.

The proposed Projects and the formation of the NY Transco are responsive to the goals and objectives set forth not only in the Commission's Order but also in the Blueprint. Further, because the NYTOs expect the transmission projects put forth in this docket need to be included in the NYISO's public policy planning process,[10] the Commission will need to facilitate that effort by taking the necessary steps to: (1) establish that there is a public policy requirement

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[9] The STARS Phase II report was made publicly available on April 30, 2012, is posted on the NYISO website and is included in this filing as Exhibit A. A copy of the Appendix to the STARS Phase II Report can be found at: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Special_Studies/STARS/Phase_2_Final_Report_Attachments_4_30_2012.pdf. The NYTOs made periodic updates and sought input in the development of the study through the NYISO's stakeholder process.

[10] In compliance with Order 1000, the NYISO and the NYTOs submitted a filing that proposed certain revisions to the NYISO OATT to include a public policy requirements planning process, which includes a cost allocation method for public policy projects, in order to bring the OATT into full compliance with Order 1000. *See*, Docket No. ER13-102, *New York Independent System Operator, Inc and New York Transmission Owners,* ("Order 1000 Compliance Filing") (October 11, 2012). FERC approval of the Order 1000 Compliance Filing is pending.

which drives the need for such upgrades to the New York State Bulk Power Transmission Facilities; and (2) establishing a public comment period pursuant to the State Administrative Procedure Act ("SAPA"). This fact was recognized by this Commission when it stated that:

> The NYPSC is committed to working with the NYISO, NYTOs, and other interested stakeholders to develop a process that fits the Commission's Order 1000 framework and facilitates the appropriate implementation of State public policy goals.[11]

Accordingly, for the reasons set forth herein, the NYTOs on behalf of the NY Transco respectfully request that the Commission:

1. Issue an order[12] no later than June 2013:[13]

    a. Authorizing the NYTOs on behalf of the NY Transco to proceed with the development of each of the Projects proposed in this filing recognizing that the implementation of the full portfolio of Projects allows for synergistic benefits;

    b. Authorizing those Projects that require an Article VII Certificate of Public Convenience and Necessity ("Article VII Certificate") to proceed with their Article VII filing and that those Projects that do not need an Article VII Certificate proceed with the remaining permitting work needed to commence construction;

    c. Finding that the cost allocation proposal specified in this filing is just and reasonable and should proceed to FERC for approval;

    d. Directing that each NYTO modify its retail cost recovery mechanisms for transmission and transmission-related costs, to the extent necessary, to provide that all FERC-approved NY Transco charges allocated to that individual NYTO will be recovered from that NYTO's retail customers; and

    e. Finding that the recovery of RIK[14] costs is approved.

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[11] December 11, 2012 *Answer of the New York State Public Service Commission* in response to protests of the joint NYISO/NYTO Order 1000 public policy planning process compliance filing, Docket ER13-102, p. 11.

[12] Throughout this filing, the term order in this context means an order of the Commission with respect to the investor owned utilities ("IOUs") and a request with respect to NYPA and LIPA.

[13] In order to meet the targeted in-service dates, certain Projects (*i.e.*, the Second Ramapo to Rock Tavern 345kV line) need an order to proceed sooner than June 2013.

2. Establish a public comment period pursuant to SAPA during the first quarter of 2013 soliciting comments regarding the public policies outlined in this docket;
3. Issue an order following the conclusion of the public comment period that:
    a. Establishes that upgrading the AC electric transmission corridor and meeting the goals identified in the Blueprint are transmission requirements that are being driven by public policy requirements; and
    b. Finds that the NY Transco Projects are public policy projects that meet these specified public policy requirements of New York State.

In addition, in order to meet the 2016 to 2018 in-service dates identified in the Blueprint, the Commission will need to establish expedited approvals for all Projects whether they require an Article VII Certificate, an updated Environmental Management and Construction Plan ("EM&CP"), or other approvals.

II. <u>BACKGROUND</u>

On April 11, 2012, the Governor's New York Energy Highway Task Force issued its Request for Information ("RFI")[15] inviting parties to "submit information concerning projects that will advance one or more of the Task Force's specific objectives."[16] The RFI further stated that "[w]e must modernize the transmission system and eliminate the bottlenecks."[17] In response to the RFI, on May 30, 2012, the NYTOs submitted a proposal consisting of a public-private partnership to jointly develop and own transmission facilities in New York State.[18] The proposed partnership anticipated the creation of a new statewide transmission entity, the NY

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[14] RIK refers to the replacement by the individual NYTO, of certain existing transmission assets within the Projects. RIK costs are allocated to the retail customers of the NYTO that owns the RIK asset (or, in the case of NYPA, through the NYPA Transmission Adjustment Charge or "NTAC").
[15] Information on the Energy Highway RFI is available at http://www.nyenergyhighway.com/.
[16] RFI, p. 6.
[17] *Id*.
[18] A copy of NY Transco RFI submission can be found at http://www.nyenergyhighway.com/Responses.html.

Transco. As indicated in the RFI statement, the NY Transco will initially pursue the planning, development, construction, and ownership of new transmission projects that will enhance the current capabilities of the bulk power system within New York State to meet the public policy objectives identified by the Task Force on behalf of the State of New York. This new structure combined with the interconnected nature of the bulk power system creates synergies among the NYTOs that permits and encourages continued investment in the State's transmission infrastructure to improve statewide reliability, provide cost-effective infrastructure improvements, and meet the public policy objectives to benefit all New Yorkers.

On October 22, 2012, the New York Energy Highway Task force issued its Blueprint. Among other things, the Blueprint calls for the construction of $1 billion of new transmission assets to provide 1,000 MW of additional transmission capacity within New York State.

On November 30, 2012, the Commission issued its Order adopting several recommendations in the Blueprint and specifically asked for:

> written public Statements of Intent from developers and transmission owners proposing projects that will increase transfer capacity through the congested transmission corridor, which includes the Central East and UPNY/SENY interfaces as described above, and meet the objectives of the Energy Highway Blueprint.[19]

This congested corridor "includes facilities connected to Marcy, New Scotland, Leeds, and Pleasant Valley substations,"[20] and four major electrical interfaces (*i.e.*, groups of circuits) that are often referred to as Central East, Total East, UPNY/ConEd, and UPNY/SENY. As indicated by the Order, "[u]pgrading this section of the transmission system has the potential to

[19] Order, p. 2.
[20] Order, p. 1.

bring a number of benefits to New York's ratepayers."[21] These benefits include, but are not limited to:

> enhanced system reliability, flexibility, and efficiency, reduced environmental and health impacts, increased diversity in supply, and 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.[22]

To that end, the Order indicated that the Commission would accept proposals of projects that need an Article VII Certificate as well as for those that do not. January 25, 2013 was established as the date for submission of Statements of Intent to construct transmission facilities.

III. DESCRIPTION OF THE NY TRANSCO PROJECTS

The NYTOs acting on behalf of the NY Transco are pleased to propose five transmission Projects that will reduce the constraints on the electric transmission system, enable excess power to move from upstate to downstate while expanding the diversity of the power generation sources able to serve downstate loads, assure the long-term reliability of the New York State electric system, provide for job growth throughout the state, and provide the additional public policy benefits as described in both the Order and in the Blueprint. The Projects, which are illustrated on the map contained in Exhibit B, consist of the following transmission facilities:

1. Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring;
2. Second Ramapo to Rock Tavern 345 kV Line;
3. UPNY/SENY Interface Upgrade;
4. Second Oakdale to Fraser 345 kV Line; and
5. Marcy to New Scotland 345 kV Line.

In total, the Projects will result in an estimated total investment in the New York transmission system of approximately $1.3 billion in 2013 dollars. The currently estimated cost

[21] Order, p. 2.
[22] Order, p. 2.

of each Project is shown in the chart below.

Estimated Project Costs[23]

Project	In-Service Year	Estimated Cost (2013 $ millions)	Estimated Cost (In service year $ millions)
Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring	2016	$69	$76
Second Ramapo to Rock Tavern 345kV Line	2016	$116	$123
UPNY/SENY Interface Upgrade	2018	$463	$553
Second Oakdale to Fraser 345kV Line	2018	$199	$231
Marcy to New Scotland 345kV Line[24]	2019	$482	$576
Total	---	$1,329	---

For a detailed description of each of these Projects, please see Exhibit C for the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring project; Exhibit D for the Second Rock Tavern to Ramapo 345 kV Line; Exhibit E for the UPNY/SENY Interface Upgrade; Exhibit F for the Second Oakdale to Fraser 345 kV Line; and Exhibit G for the Marcy to New Scotland 345 kV Line. Exhibit H contains a copy of the single line diagrams for each project.

As indicated in these detailed project descriptions, each of the proposed Projects can be completed in the 2016 to 2019 time frame as they have already commenced preliminary engineering evaluations and, in the case of certain of these Projects, have already initiated or

[23] The preliminary cost estimates included are based on conceptual project scopes and represent an order of magnitude reference for future project costs. As preliminary engineering and project tasks proceed, additional detail and certainty will support updated cost estimates.
[24] Cost estimate includes approximately $105 million of RIK contribution.

received NYISO and/or Commission approval.[25] Specifically, the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring Project can be in service in the summer of 2016 provided licensing and major permitting are completed by the end of 2013. Similarly, the Second Rock Tavern to Ramapo 345 kV Line, which already has its Article VII Certificate, can be in service in the summer of 2016 provided that it receives approval of its updated EM&CP by the end of 2013. The UPNY/SENY Interface Upgrade can be in service in 2018 provided it receives Article VII approval by the end of the second quarter 2015. The Second Oakdale to Fraser 345 kV Line is estimated to be in service in 2018 based on it receiving its Article VII approval by the middle of 2016. Finally, the Marcy to New Scotland 345 kV Line can be in service by the end of 2019 based on it receiving its Article VII approval by the end of the third quarter of 2016, although parts of this project are expected to be in service in 2017 and 2018. The chart below indicates the study, permit or license approvals received to date for the Projects.

[25] Meeting these completion dates would require swift action by the State in order to authorize the projects to move ahead, including identification of these projects as required under FERC's Order 1000. Furthermore, the process also assumes that the FERC will act on the pending Order 1000 Compliance Filing in a timely manner.

Project Approvals Received to Date

Second Ramapo to Rock Tavern 345kV Line	• NYISO approved SIS August 16, 2012; Queue position 368 • Article VII Certificate Received January 25, 1972, Case 25845, Con Edison and Case 25741, Con Edison and O&R • Article VII Certificate Received January 24, 2011, Case 10-T-0283, O&R (Feeder 28)
Marcy Series Compensation and Fraser to Coopers Corners Reconductoring	• NYISO Interconnection Application filed May 12, 2012; Queue position 380
UNPNY/SENY Interface Upgrade	• NYISO Interconnection Application filed June 15, 2012; Queue positions 384 and 385

IV. THE NY TRANSCO'S PROJECTS SATISFY THE ORDER'S GOALS AS WELL AS THE GOALS OF THE NEW YORK ENERGY HIGHWAY BLUEPRINT

This section describes how the Projects address the goals and objectives identified in the Order as well as in the Blueprint. The NYTOs understand that this proceeding is an open proceeding where other parties can submit projects but the NYTOs are confident that the Commission will ultimately select the NY Transco's Projects as being the best set of projects to meet the stated public policy needs. As shown herein, the Projects significantly expand the capability of the transmission system, which will enable power flows to increase between upstate and downstate areas.

A. The NY Transco Projects are Inter-related

The Projects are a subset of those that were submitted in response to the Energy Highway RFI process and that were supported by the results documented in the STARS Phase II Report. One of the important aspects of the NY Transco Projects is the inter-related nature of the

Projects, an impact that can be shown in terms of quantifiable Project benefits. The total benefits of each Project are substantially greater when all Projects are studied in total rather than if each Project were to be analyzed individually. As such, the Projects' benefits summarized below represent those related to the combined effect of all the proposed Projects.

B. The Projects Are an Efficient Way to Reduce Congestion Across Central East and the UPNY/SENY Interfaces

1. The Projects Will Increase Transfer Capability

The electric transmission system moves power from region to region across the state in a generally west to east, north to south direction. The western and northern regions of the state are net exporters of electric generation whereas the more heavily populated southeastern regions of the State are net importers of electricity. Much of the existing and potential generation in the western and northern regions of the state can be produced at a lower total cost than the generation in New York City and Long Island. While there remains a need for local generation in the downstate region, producers and consumers across the state can benefit if electricity exports can increase from upstate to downstate. For example, while consumers in some areas will have access to lower-priced electricity, suppliers in other areas of the state will have an increased opportunity to compete for sales throughout the state if transmission congestion across Central East, Total East, UPNY/ConEd, and UPNY/SENY is reduced.

Currently, transmitting electricity between regions in the state is limited by the lack of transmission transfer capability. When export flows reach the transmission transfer capability, the transmission system becomes constrained, or congested, and more costly local generation is needed to meet customer needs. Generally, congestion costs alone have not been sufficient to justify long term investment in transmission assets without a public policy directive from the state recognizing the other benefits that are not reflected in the evaluation of such projects, including benefits to statewide and local economies, job creation and environmental impacts. These constraints have a negative environmental, reliability, and cost impact on consumers.[26] Moreover, public policy considerations dictate addressing those constraints and the realization of related benefits.

The STARS initiative examined the economics and reliability benefits of eliminating these constraints by replacing and/or expanding existing transmission infrastructure, including advancing projects that might be needed in the future based on transmission condition assessment. The Projects will increase upstate to downstate normal transfer capability on critical transmission interfaces as shown in the chart below. An explanation of how these interface limits were determined is contained in Exhibit I.

Increase in Upstate to Downstate Normal Transfer Capability

Resulting From the Projects

NYISO Transmission Interface	Base case Limit (MW)	New Limit (MW)	Net Increase (MW)
UPNY/SENY	5,942	7,462	1,520
UPNY/ConEd	6,297	8,674	2,377
Central East	3,151	3,595	444
Total East	4,640	5,169	529

2. The Projects Will Result in Electricity Cost Savings

The Projects will provide significant economic benefits in terms of production cost savings. Production costs are the total costs incurred by generators to produce power within a region. These include costs for fuel, maintenance and emissions. The annual statewide

[26] According to the NYISO's 2011 Congestion Assessment and Resource Integration Study ("CARIS") these constraints resulted in a total congestion cost of approximately $1 billion in 2010.

production cost savings of these Projects is estimated to be $176 million.[27] This benefit is a direct result of increasing transfer capability from upstate to downstate New York thereby freeing constrained (bottled) economic and renewable generation in western and northern New York. These Projects have the potential to provide even greater economic and public policy benefits under certain situations such as if generator fuel costs were to significantly increase or if a disproportionate amount of new generation is sited remotely rather than in proximity to future load growth. The Projects most closely align with Trial 4 of the STARS Phase II Report which is the basis for the estimated production cost savings. A more detailed explanation of these benefits can be found in the STARS Phase II Report.

An additional benefit that these Projects offer is a reduction to the ICAP costs for the entire New York control area. According to the NYISO, increasing transfer capability across these constrained interfaces will result in less generating capacity in order to maintain statewide reliability.[28] The Projects will eliminate the need for this generation providing a potential annual savings in the range of $50 million to $200 million, which could vary year to year.[29]

Further, the Projects could also mitigate the price impacts associated with adding a new installed capacity zone in the Lower Hudson Valley region as well as potentially mitigate the need for such a zone in the future.

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[27] STARS Phase II Report, p. 53.

[28] See 2011 Congestion Assessment and Resource Integration Study CARIS – Phase 1, Appendix E for more details.
http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2011_CARIS_Appendices_Final_Approved_by__Board_3_20_2012.pdf

[29] STARS Phase II Report, p. 70.

C. <u>The Projects Will Enhance Electric Reliability</u>

1. <u>The Projects Will Improve LOLE</u>

The Projects also provide tangible reliability enhancements that result from a more robust transmission system. These reliability enhancements include increased emergency transfer capability and improved access to on-line resources. The standard reliability metric used in New York State and in the Northeast is Loss of Load Expectation ("LOLE"). This is a measure of the probability that there will be enough generation to serve system wide load. The accepted LOLE standard is that there will be enough generation to serve load for all but one day in ten years, or 0.1 days/year. The development of the proposed Projects would reduce the installed reserves necessary to meet the one day in ten year criterion. The LOLE benefit could be greater if more generation in the future is developed further from the load than the STARS Phase II Report analysis assumed, *i.e.*, more generation is developed in the future in the upstate region as opposed to evenly distributed across the state.

2. <u>The Projects Will Enhance Transmission Availability</u>

One key part of improving reliability is that the Projects will improve the availability of the bulk power infrastructure. The STARS study performed a high-level age-based condition assessment of the transmission system. It evaluated lines that will require significant investment over the next 30 years. This assessment combined with independent analyses performed by some of the NYTOs identified the Porter-Rotterdam 230kV transmission lines as requiring a total investment of approximately $105 million to address condition assessment issues. Retiring the Porter-Rotterdam 230kV lines and constructing a new Marcy-New Scotland transmission line would create additional statewide benefits by being upgraded rather than by being replaced in kind. The Projects together with the process to replace facilities based on condition assessment allow the existing transmission system to remain in reliable operating condition well into the future while simultaneously enlarging its capacity.

3. The Projects Address Reliability Concerns Associated with Potential Downstate Generation Retirements

The Projects increase the transmission transfer capability into the Lower Hudson Valley region which ultimately enables more power to flow into the New York City and Long Island regions. They address reliability issues that could occur if a large generation resource in this region shuts down. While these deficiencies may not be entirely mitigated with transmission, the transmission reinforcements proposed herein would materially mitigate the loss of those facilities. The Projects that address this objective include the UPNY/SENY Interface Upgrade, the Second Ramapo to Rock Tavern 345kV Line, and the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring. These projects, when coupled with the Staten Island Un-bottling project,[30] will provide an estimated transmission security benefit of almost 2,000 MW which would ensure that the transmission system operates adequately during emergency conditions.

D. The Projects Will Create Long Term Economic Development Benefits

The Projects are estimated to cost approximately $1.3 billion in 2013 dollars. As a result of this investment, the New York State economy will reap significant economic development benefits in the form of increased employment and increases in local tax revenues.

Based on analyses performed by the Working Group for Investment in Reliable and Economic Electric Systems (the "WIRES" group) in conjunction with the Brattle Group, this $1.3 billion of investment will support an estimated 6,000 direct full time equivalent ("FTE")

[30] Please see the discussion later in this filing regarding the Staten Island Un-bottling project.

jobs and nearly 17,000 total FTE jobs.[31] The directly supported jobs represent those related to domestic construction, engineering and transmission component manufacturing. Indirect job stimulation represents suppliers to the construction, engineering and equipment manufacturing sectors as well as jobs created in the service industries (*i.e.*, food and clothing) supporting those directly and indirectly employed.

The Projects are also estimated to increase annual local tax revenue by approximately $25 to $40 million.[32] The majority of this increased revenue will flow to upstate and western regions of New York.

E. **The Projects Will Result in Reduced Environmental and Health Impacts**

1. **Emissions Reductions**

The Projects will allow for a significant amount of constrained wind energy to be delivered as well as allow for other potentially cleaner upstate resources to be dispatched. The estimated net statewide benefit of the Projects is a reduction in CO_2 emissions of more than 227,000 tons and NO_X emissions of more than 83 tons annually. These calculations were based on the STARS Phase II Report.

2. **Leveraging Existing Rights-of-Way**

The Projects represent approximately 320 circuit miles of 345 kV and 115 kV transmission facilities. If they were to be constructed on all new ROW, they would require the

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[31] The direct and total job numbers are based on generic information included in the May 2011 report entitled *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, which was developed by the WIRES group in conjunction with the Brattle Group. The report concluded that every $1.0 billion of transmission investment supports 4,250 direct FTE years of employment and 13,000 total FTE equivalent years of employment. This report can be found at the following link: http://www.wiresgroup.com/images/Brattle-WIRES_Jobs_Study_May2011.pdf.

[32] The estimated annual local tax revenue associated with these projects is based on a factor of approximately 2 -3% of project capital costs. This factor is consistent with the NYTOs' experience for similar type projects.

acquisition of additional property to accommodate the ROWs needed. However, because the Projects are leveraging to the greatest extent possible previously disturbed land along existing ROW, only approximately two square miles of new ROW will be needed most of which will be adjacent to existing ROW. This represents an 80 percent reduction in the amount of land that could be potentially impacted as compared to if the Projects were developed as Greenfield projects. The Projects will be designed so that transmission infrastructure that needs to be replaced will be replaced in an efficient, environmentally friendly, and cost-effective manner. To the extent possible, new transmission facilities will be built using existing transmission ROW and in some cases using existing transmission towers. In addition, economies of scale will be created by replacing and expanding existing transmission facilities with new higher voltage lines or by adding to existing capacity. Using existing ROWs will also enable the Projects to be built faster than if new land had to be acquired for these Projects.

NYTOs have long been responsible stewards of the environment. For example, the NYTOs' ROWs provide habitat for many species. Because of this, the NYTOs have an excellent working relationship with the New York State Department of Environmental Conservation and the Commission, which enables the NYTOs to effectively collaborate on project design and construction practices. The NY Transco will be committed to continuing this relationship and being responsible stewards of the environment.

V. DESCRIPTION OF THE NEW YORK TRANSCO

A. Corporate Description

The NYTOs are in the process of creating a transmission company, the NY Transco, which will seek to develop transmission in New York State including those Projects represented herein. The NY Transco will be a New York limited liability company ("LLC") that will be owned by affiliates of the NYTOs. The NY Transco's mission will be to identify and develop transmission projects for the New York bulk power system that provide long term value to New York's electricity consumers. NY Transco's business and operations will be limited to the planning, developing, construction and ownership of transmission assets; it will not own, operate or be involved in the local distribution or generation of electricity. The new structure will allow the NY Transco to develop and own incremental new projects, while the NYTOs will continue to own and invest in all pre-existing assets that have been developed to serve their respective customers. This new structure creates synergies among the NYTOs that permits and encourages continued investment in the state's transmission infrastructure to improve statewide reliability and provide cost-effective infrastructure improvements to benefit all New Yorkers.

It is anticipated that the NY Transco will be formed in October 2013. The NYTOs are in the process of developing the regulatory filings necessary to establish a transmission rate schedule at FERC as well as to implement the cost allocation and cost recovery mechanisms through the NYISO's tariff as described herein. Filings are also being developed, to the extent necessary, to address recovery of RIK investments[33] and retail recovery of any NYISO tariff charges that would be allocated to the NYTOs as a result of these Projects. Final regulatory approvals from the Commission and FERC are anticipated in April 2014. Once FERC approval is obtained the NY Transco will assume the leadership in the development of the proposed Projects.

NYPA and LIPA plan to participate in the NY Transco as direct equity owners but will need legislative authorization to do so. This public/private partnership is critical because together they own facilities throughout the state, many of which are integral to the development

[33] An example of a Project with RIK is the Marcy to New Scotland 345kV line.

of the Projects. Including NYPA and LIPA in equity ownership structure improves the ability of the NY Transco to develop new transmission throughout the state in a more streamlined, efficient fashion and at lower total cost.

B. Relationship of NY Transco to the NYISO

The NY Transco plans to provide the NYISO with operational control[34] of its assets consistent with the operation of the majority of the transmission system in New York State. This means that the NYISO will be responsible for tariff administration, scheduling, OASIS operation and billing of the NY Transco's transmission assets. The NY Transco will become a signatory to the relevant NYISO agreements and tariffs and will comply with all of the NYISO's applicable rules and regulations.

C. Relationship of the NY Transco to the Individual NYTOs

As affiliates to NY Transco, the NYTOs will provide business support functions, as needed, to NY Transco for the development of the Projects that will be built within a NYTO's respective transmission districts or corridors. As assets are placed into service, it is anticipated that the NYTO that has responsibility for the operation and maintenance of the transmission facilities where the Project is located will perform the maintenance and physical operation of the NY Transco assets in that corridor consistent with the respective NYTO's existing operating and maintenance practices and pursuant to an operations and maintenance agreement between NY Transco and the applicable NYTO. Most substation assets will be operated and maintained by the respective NYTO. The NYTO will be compensated by the NY Transco for all project

[34] Similar to existing NYTO assets under NYISO operational control, the NYISO will direct operation and scheduling activities, while the applicable NYTO will perform actual operation and switching activities.

delivery, operations and maintenance services provided by a NYTO at the cost of service consistent with the affiliate rules and requirements of both the Commission and the FERC.

Any transfer of assets, if needed, to the NY Transco from an IOU will be undertaken pursuant to a filing with the Commission pursuant to Section 70 of the Public Service Law [35] and a filing with FERC pursuant to Section 203 of the Federal Power Act ("FPA").[36]

VI. THE NY TRANSCO'S PROPOSED COST ALLOCATION, COST RECOVERY AND FINANCING STRUCTURE IS APPROPRIATE

A. The NY Transco's Cost Allocation Proposal is Reasonable

Historically, it has been difficult for large transmission projects to get built in New York State. One of the reasons has been the lack of agreement on how estimated project costs should be allocated among load serving entities. As part of the NYTOs' unique public/private partnership to create the NY Transco and build the Projects put forth in this filing, the NYTOs have developed a cost allocation method that takes into account the wide range of public policy, economic and reliability benefits provided by the Projects.[37] The agreed to cost allocation recognizes the differing levels and types of benefits that will occur in different areas of the state. Indeed, as indicated earlier in this filing, the Projects will not only provide lower production costs but will also provide lower emissions, increase tax revenues, create thousands of jobs and enhance reliability. Moreover, the impact of these different types of benefits differs depending on the region of the state. While the downstate region may experience a greater impact from lower electricity prices than the upstate regions, the upstate and western regions of the state will

[35] 47 New York Pub. Serv. Law §70.
[36] 16 U.S.C. § 824b.
[37] The various Project benefits have been detailed throughout this filing.

benefit from economic development in the form of increased employment and increased property tax revenues and the state as a whole will benefit from cleaner resources being dispatched.

Importantly, as a result of this agreement on specific cost allocation factors and the funding requirements of each NY Transco member, the NYTOs have agreed to form the NY Transco and to move forward and build the Projects based on the following cost allocation percentages: Central Hudson Transmission District 5.4%; Con Edison/O&R Transmission District 41.7%; LIPA Transmission District 16.7%; National Grid Transmission District 10.4%; NYSEG/RG&E Transmission District 8.9%; and NYPA[38] 16.9%.

The proposed cost allocation methodology is an adjusted load ratio share which accounts for the fact that the benefits of the Projects flow throughout the state and include economic, reliability, economic development, job creation, and environmental among other benefits. This concept was recognized by the Commission in its response at FERC to various protests of the joint Order 1000 Compliance Filing when it stated that:

> Contrary to the CARIS[39] approach, public policy projects are intended to address broader policy considerations, such as environmental benefits or the promotion of renewable resources.[40]

The Commission's pleading clearly recognized that public policy projects provide benefits throughout the state and that their cost allocation should be dissimilar to that of economic projects. Specifically, the Commission stated that:

> For example, a transmission project from western to central New York may permit delivery of more wind resources to the bulk transmission system, in furtherance of New York's Renewable

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[38] Costs allocated to NYPA will flow to its contract customers.

[39] The NYISO's Congestion Assessment and Resource Integration Study (or CARIS) is the NYISO's economic planning process for new transmission projects as part of its overall planning process as set forth in Attachment Y to the NYISO OATT.

[40] December 11, 2012 *Answer of the New York State Public Service Commission* in response to protests of the joint Order 1000 Compliance Filing, Docket ER13-102, p. 12.

> Portfolio Standard goals. Because the primary benefits under such a project may not be in the form of immediate price reductions, utilizing the CARIS formula could assign the bulk of the costs narrowly to the delivery point on the bulk transmission system in central New York, and ignore the Statewide benefits of additional wind resources and other related transmission upgrades.[41]

Because of the wide portfolio of benefits produced by the NY Transco's Projects as described herein, the NY Transco's proposed cost allocation method is reasonable and should be endorsed. Moreover, because public policies established by New York State provide benefits to consumers across the state, it is reasonable to have a cost allocation method that allocates costs throughout the state.

Order 1000 recognizes that the costs of public policy projects should not necessarily be allocated in the same manner as economic or reliability projects because public policy projects provide additional types of benefits such as those described in this filing. Specifically, cost allocation principle number one from Order 1000 provides that:

> In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.[42]

Moreover, the NYTOs' proposed cost allocation method is consistent with the Order 1000 Compliance Filing made by the NYISO and NYTOs in response to FERC's Order 1000. That filing provided that if a cost allocation methodology is not specified by the applicable Federal or New York State statute, regulation or Commission Order concerning public policy

[41] *Id.*, p. 13.
[42] Order 1000, P 586.

requirements, transmission developers can propose cost allocation methods to both the Commission and FERC, again recognizing that public policy transmission projects, such as the Projects, provide various types of benefits throughout a region.

B. The Cost Recovery Mechanism is Reasonable

With respect to cost recovery, the NYTOs, on behalf of the NY Transco, will pursue FERC approval of a transmission revenue requirement and rate that would become part of the NYISO's Open Access Transmission Tariff ("OATT"). Once approved by FERC, the NY Transco's revenue requirement will be recovered from ***all*** load serving entities ("LSEs") in the NYISO's control area. LSEs include ESCOs, the NYTOs with respect to their full-service customers, public power and municipal/cooperative entities. The NYISO will be responsible for billing and collecting the NY Transco's revenue requirement from all LSEs based on their energy consumption and location. The NY Transco will receive payments from the NYISO after the NYISO receives payments from the LSEs. The NYTOs, in their role as an LSE, will charge this NYISO-billed amount to their full service retail customers consistent with their existing PSC-approved retail tariffs or, where necessary, under newly approved PSC tariffs. In this regard, the NY Transco charge will be recovered from retail ratepayers in a way that resembles the current way investor owned NYTOs recover other NYISO charges, such as NYISO Rate Schedule 1 and the NYPA Transmission Adjustment Charge. In order to effectuate this cost recovery mechanism, the Commission should order each NYTO to modify its retail cost recovery mechanisms for transmission and transmission related costs, to the extent needed, to provide that all FERC-approved NY Transco charges allocated to an individual NYTO will be recovered from that NYTO's full service retail customers.

C. The NY Transco's Financing Structure is Appropriate

As indicated above, the NY Transco initially will be wholly owned by affiliates of the NYTOs. It is anticipated that the NY Transco will finance with fifty percent debt and fifty percent equity. Once the NY Transco's transmission rate is approved by FERC, it is anticipated that the NY Transco will be able to obtain investment grade construction debt financing. Equity support during construction will be provided to the NY Transco by the NYTOs' affiliates. The NY Transco also anticipates receiving various FERC incentives which are anticipated to reduce project risks (*e.g.*, construction work in progress). The construction debt financing will be converted to permanent financing post commercial operation. Post construction, equity support, to the extent necessary, will be provided to the NY Transco by its owners.

VII. REGULATORY MATTERS

A. Commission and FERC Jurisdiction

As shown below, the NY Transco, its Projects, its rates and its agreements will be subject to the regulatory oversight of the Commission and FERC. Pursuant to Article VII of the New York State Public Service Law,[43] the Commission has jurisdiction over the siting of the proposed transmission Projects and over the IOU NYTOs' recovery through retail rates of the NY Transco projects costs that the NYISO allocates to them. The Commission also has an important advisory role regarding the NYISO's allocation of the costs of the NY Transco's Projects in this proceeding.

The sole business of the NY Transco will be the planning, developing, and owning of transmission facilities. Pursuant to Section 201 of the FPA,[44] FERC has jurisdiction over the rates and terms for transmission services. Accordingly, as indicated above, the NYTOs, on

[43] 47 New York Pub. Serv. Law §120 *et seq*.
[44] *See* 16 U.S.C. §824.

behalf of the NY Transco, will pursue the establishment of a wholesale transmission revenue requirement and formula rate that would be approved by FERC. FERC also has jurisdiction over any transmission incentives that the NY Transco may pursue. Consistent with the requirements of FERC's Order 1000, and assuming FERC approval of the joint NYISO/NYTO Order 1000 compliance filing, FERC would approve the NYTOs proposed costs allocation and cost recovery mechanism. In addition, since the NY Transco's rates will be recovered through the NYISO OATT, any modifications to that tariff must be approved by FERC. Finally, several of the NY Transco's agreements must be filed with and accepted by FERC.

B. The Commission Should Establish A Process To Enable the NY Transco to <u>Comply With Order 1000</u>

The joint NYISO/NYTO compliance filing to implement the public policy requirements of Order 1000 defines a public policy requirement as:

> A federal or New York State statute or regulation, including a NYPSC order adopting a rule or regulation subject to and in accordance with the State Administrative Procedure Act, or any successor statute, that drives the need for expansion or upgrades to the New York State Bulk Power Transmission Facilities.[45]

By including the reference to the SAPA, the filing clearly intended that market participants and other stakeholders would have an opportunity to comment on the proposed public policy and to participate in the debate with respect to projects that are submitted in response to the enunciated public policy. While the Order clearly sets forth the public policy of the state with respect to the need to "increase transfer capability through the congested transmission corridor,"[46] and "meet the objectives of the Energy Highway Blueprint,"[47] the Order does not provide for an opportunity for market participants to comment on the enunciated

[45] October 11, 2012 joint NYISO/NYTO compliance filing.
[46] Order, p. 2.
[47] Id.

public policy. The NYTOs agree that it is important for market participants to have the opportunity to weigh in on the important policy goals set forth in the Order. Moreover, since the transmission projects put forth in this docket need to be included in the NYISO's public policy planning process, orders issued by the Commission should facilitate that effort, including establishing a public comment period pursuant to the SAPA. The need for this process was recognized by the Commission in its filing in FERC docket ER13-102 (the Order 1000 docket) when it stated that:

> The NYPSC is committed to working with the NYISO, NYTOs, and other interested stakeholders to develop a process that fits the Commission's Order 1000 framework and facilitates the appropriate implementation of State public policy goals.[48]

The Commission's need to establish procedures consistent with the proposed public policy planning process in the joint NYISO/NYTO Order 1000 compliance filing was also recognized by Commission Chair Garry Brown in a letter to the NYISO where he stated that:

> I am cognizant that implementation of the proposed process would require the development of procedures that would be used by DPS Staff and the NYPSC in undertaking their respective roles and responsibilities. Please be advised that the NYPSC is prepared to initiate a proceeding, at an appropriate time, to develop and identify these procedures.[49]

In order to enable the Projects submitted by the NY Transco and projects proposed by other developers to move forward under the NYISO's public policy planning process, the Commission needs to take certain steps, in addition to the issuance of its November 30th Order,

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[48] December 11, 2012 *Answer of the New York State Public Service Commission* in response to protests of the joint NYISO/NYTO Order 1000 public policy planning process compliance filing, Docket ER13-102, p. 11. The joint NYISO/NYTO compliance filing is currently pending before FERC.

[49] September 27, 2012 letter from Commission Chair Garry Brown to NYISO President and Chief Executive Officer Stephen G. Whitley. This was included at Attachment II in the October 11, 2012 NYISO/NYTO Order 1000 compliance filing. A copy of this letter is attached as Exhibit J.

to establish that there is a public policy that drives the need for upgrades to the New York State Bulk Power Transmission Facilities. These steps include: (1) establishing a comment period in this docket consistent with the requirements of SAPA; (2) issuing a subsequent order establishing the public policy; and (3) determining that the Projects meet the identified public policies and should therefore proceed to request the necessary local, state, and federal authorization for construction and authorization of the Projects.[50] This is the process that the Commission is required to undertake in order to satisfy its role in the NYISO's filed Order 1000 public policy planning process.

Finally, in evaluating the various transmission projects submitted in this proceeding, the Commission should recognize that certain projects do not need an Article VII Certificate because they either already have one (*i.e.*, NY Transco's Ramapo to Rock Tavern Project) or because the Certificate may not be necessary (*i.e.*, NY Transco's Marcy South Series Compensation and Fraser to Coopers Corner Reconductoring Project). Thus, future processes that arise out of this proceeding should not delay projects that do not need an Article VII Certificate pending the outcome of Article VII proceedings for other projects. Accordingly, for all of the reasons cited above, the Commission should issue an order prior to the commencement of any Article VII proceeding, finding that the NY Transco Projects are public policy projects.

C. Required Actions and Approvals for NY Transco Formation

In order for the NY Transco to be formed and eventually take over the management, and development, of the Projects, the following additional regulatory and governmental actions are necessary:

(1) FERC approval of the cost allocation and recovery mechanisms specified in this filing;

[50] The Order 1000 Compliance filing also requires the NYISO to evaluate the Projects.

(2) Enactment of legislation to enable NYPA and LIPA to participate in the NY Transco as full equity owners;

(3) FERC approval of the NY Transco transmission rate and revenue requirement;

(4) Inclusion of the Projects in the NYISO planning process;

(5) Commission approval, to the extent needed, of the ability of each of the NYTOs to recover the costs of the NY Transco Projects (including the RIK piece as applicable) from their retail ratepayers; and

(6) The various construction-permit approvals as detailed herein.

D. Permit Approval Process

The NY Transco will be committed to constructing electric transmission projects that will minimize the impact to the environment and local communities. The Projects will be submitted, as required, to the appropriate Federal, State, and Local agencies for review and approval. NY Transco will collaborate with all agencies and host utilities to develop the best projects for the State of New York. The permits required will depend on each Project's scope and proposed route, which have not been finalized for some of the Projects. A listing of the most common agencies and quasi-governmental entities that the NY Transco can expect to interface with to obtain the necessary permits and approvals is set forth immediately below:

- NY Public Service Commission
- NY Office of General Services
- NY Office of Parks, Recreation, and
- U.S. Army Corp of Engineers
- NYISO
- FERC
- NY Dept. of Environmental
- NY Dept. of Transportation
- NY Agriculture and Markets
- Federal Aviation Administration
- Adirondack Park Agency

E. Other Potential NY Transco Projects

As part of the response to the Request for Information by the Energy Highway Task Force, the NYTOs representing the NY Transco proposed 18 major Projects including the Moses to Marcy Project, the Staten Island Un-bottling project, and the East Garden City to Newbridge Road Upgrade project. The Moses to Marcy, Staten Island Un-bottling, and East Garden City to Newbridge Road Upgrade projects are not included in this submittal because the Commission's Proceeding to Examine Alternating Current Transmission Upgrades is focused on "projects that will increase the transfer capacity through the congested transmission corridor, which includes the Central East and UPNY/SENY interfaces."[51] None of these projects will affect that interface.[52]

The Moses to Marcy project reduces constraints on the flow of electricity to the downstate area; it increases the transfer capability at the Moses South interface by over 2000 MW. The project would be constructed within the existing Moses to Marcy ROW with minimal need for additional land. Approximately half of the 230kV system between Moses to Marcy is over 60 years old and needs to be replaced. In anticipating future needs for a robust transmission system, it makes sense to replace the existing 230kV transmission facilities with new ones that have a higher voltage or greater capacity (345kV). The project also provides tangible reliability benefits that result from a more robust transmission system. These reliability benefits include increased emergency transfer capability, improved resource adequacy, and a reduction in the amount of generation required to maintain system reliability.

The Staten Island Un-bottling project will increase transmission capacity between Goethals, Gowanus, and Farragut Substations thereby enabling additional generation to reach New York City. The project would be located in Staten Island and Brooklyn, New York and Union County (Linden), New Jersey.

[51] Order, p. 2.
[52] Other projects that would facilitate wind development are also excluded.

The East Garden City to Newbridge Road Upgrade project will increase transmission capacity between Long Island and Westchester County, thereby enabling additional generation to reach the lower Hudson Valley Region. The project would be located on Long Island.

VIII. DESCRIPTION OF THE NEW YORK TRANSMISSION OWNERS

The NYTOs are submitting this filing on behalf of the NY Transco. The equity members of the New York Transco will include affiliates of all of the NYTOs, including the investor owned private utilities Central Hudson, Con Edison, National Grid, and NYSEG. It also includes the participation of two state authorities, NYPA and LIPA. The New York Transmission Owners are members of the NYISO in the Transmission Owners sector, or in the case of the state public authorities, the Public Power sector. Each of the NYTOs have a significant interest in this proceeding and therefore request party status in this proceeding.

Central Hudson is a regulated public utility organized under the laws of the State of New York. Central Hudson is engaged in the transmission and distribution of electric power and natural gas, and provides electric service to 300,000 customers within eight counties of New York State. The Company owns 629 miles of electric transmission lines, 8,700 miles of electric distribution lines and 85 substations. In 2011, Central Hudson had total assets of $1.6 billion and revenues of $700 million. Central Hudson is a wholly-owned subsidiary of CH Energy Group, Inc.

Con Edison and O&R are regulated public utilities that are subsidiaries of Consolidated Edison, Inc., a holding company. In 2011, Consolidated Edison, Inc. had $39.2 billion in assets and $12.9 billion in revenues. Con Edison serves a 660 square mile area with a population of more than nine million people. In that area, Con Edison serves approximately 3.3 million electric customers, 1.1 million gas customers, and 1,700 steam customers. Con Edison provides electric service in New York City and most of Westchester County, gas service in parts of New York City and steam service within the borough of Manhattan. Con Edison has approximately 1,180 circuit miles of transmission, including 438 circuit miles of overhead and 742 circuit miles of underground transmission. O&R and its utility subsidiaries, Rockland Electric Company and Pike County Light & Power Company, operate in Orange, Rockland and part of Sullivan counties in New York State and in parts of Pennsylvania and New Jersey, and serve a 1,350 square mile area. O&R provides electric service to approximately 300,000 customers and gas service to 100,000 customers in southeastern New York and in adjacent areas of northern New Jersey and northeastern Pennsylvania. O&R has approximately 558 circuit miles of transmission.

NYSEG is a regulated public utility organized under the laws of the State of New York. NYSEG is engaged in the transmission and distribution of electric power and natural gas. NYSEG provides electric service to 878,000 customers in 42 counties in New York State. The Company owns 4,583 miles of electric transmission lines, 32,881 miles of electric distribution lines and 444 substations. In 2011, NYSEG had total assets of $4.4 billion and revenues of $1.7 billion. NYSEG is a wholly-owned subsidiary of Iberdrola USA, Inc., which in turn is a subsidiary of Iberdrola, S.A. (an international energy company listed on the Madrid Stock Exchange). RG&E is a regulated public utility organized under the laws of the State of New York. RG&E is engaged in the transmission and distribution of electric power and natural gas. RG&E provides electric service to 367,000 customers in nine counties in New York State. The Company owns 1,017 miles of electric transmission lines, 7,597 miles of electric distribution lines and 177 substations. In 2011, RG&E had total assets of $2.7 billion and revenues of $950 million. RG&E is a wholly-owned subsidiary of Iberdrola USA, Inc., which in turn is a subsidiary of Iberdrola, S.A. (an international energy company listed on the Madrid Stock Exchange).

Niagara Mohawk Power Corporation was organized in 1937 under the laws of New York State and is engaged principally in the regulated energy delivery business in New York State. Niagara Mohawk provides electric service to approximately 1.6 million electric customers in the areas of eastern, central, northern and western New York. Niagara Mohawk owns over 6,000 miles of electric transmission lines and over 700 substations. In 2011, Niagara Mohawk had total assets of $11.1 billion and revenues of $3.3 billion. Niagara Mohawk is a wholly-owned subsidiary of Niagara Mohawk Holdings, Inc., which is wholly-owned by National Grid USA ("NGUSA"), a public utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution and sale of both natural gas and electricity. NGUSA is an indirectly-owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

LIPA is a corporate municipal instrumentality and a political subdivision of the State of New York. LIPA began operating in 1998 as a non-profit municipal electric provider owning the retail electric transmission and distribution system on Long Island that provides electric service to Nassau and Suffolk counties and the Rockaway Peninsula in Queens and provides electric service to 1.1 million customers. LIPA owns 1,300 miles of electric transmission lines, 13,600 miles of electric distribution lines and 110 substations. In 2011, it had 21,000 GWh of electricity sales, revenues of $3.7 billion and total assets of $11.8 billion. LIPA is a fiscally independent public corporation that does not receive State funds, tax revenues or credits.

NYPA is a corporate municipal instrumentality and a political subdivision of the State of New York. NYPA owns and operates 16 generating facilities and about 1,400 circuit miles of high voltage transmission lines. The electricity it generates and purchases is sold to municipally owned utilities and electric cooperatives, as well as to a variety of business, industrial and public customers throughout the State. NYPA uses no tax money or state credit. It finances its operations through the sale of bonds and revenues earned in large part through sales of electricity.

IX. CONTACT INFORMATION

The following people should be added to the official service list in this proceeding:

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X. LIST OF EXHIBITS

This filing contains the following exhibits:

Exhibit A – STARS Phase II Report

Exhibit B - Map of the Proposed Projects

Exhibit C – Detailed Description of the Marcy South Series Compensation and Fraser to Coopers Corners Reconductoring

Exhibit D – Detailed Description of the Second Ramapo to Rock Tavern 345 kV Line

Exhibit E – Detailed Description of the UPNY/SENY Interface Upgrade Project

Exhibit F – Detailed Description of the Second Oakdale to Fraser 345 kV Line

Exhibit G – Detailed Description of the Marcy to New Scotland 345 kV Line

Exhibit H – Single line diagrams

Exhibit I – STARS Transmission Effects on New York Transfer Limits

Exhibit J – Letter from Public Service Commission Chairman Garry Brown to New York independent System Operator President and Chief Executive Officer Stephen Whitley

XI. CONCLUSION

As shown herein, the NY Transco and its Projects are responsive to the requirements of both the Order and the Governor's Energy Highway Blueprint and should proceed forward to completion. But, there are actions that the Commission needs to take to help these Projects move forward. Accordingly, for the reasons set forth herein, the NYTOs on behalf of the NY Transco respectfully request that the Commission:

1. Issue an order no later than June 2013: [53]

    a. Authorizing the NYTOs on behalf of the NY Transco to proceed with the development of each of the Projects proposed in this filing recognizing that the implementation of the full portfolio of Projects allows for synergistic benefits;

    b. Authorizing those Projects that require an Article VII Certificate proceed with their Article VII filing and that those Projects that do not need an Article VII Certificate proceed with the remaining permitting work needed to commence construction;

    c. Finding that the cost allocation proposal specified in this filing is just and reasonable and should proceed to FERC for approval;

    d. Directing that each NYTO modify its retail cost recovery mechanisms for transmission and transmission-related costs, to the extent necessary, to provide that all FERC-approved NY Transco charges allocated to that individual NYTO will be recovered from that NYTO's retail customers; and

    e. Finding that the recovery of RIK costs is approved.

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[53] In order to meet the targeted in-service dates, certain Projects (*i.e.*, the Second Ramapo to Rock Tavern 345kV line) need an order to proceed sooner than June 2013.

2. Establishes a public comment period in this docket pursuant to SAPA during the first quarter of 2013 soliciting comments regarding the public policies outlined in this docket;
3. Issue an order following the conclusion of the public comment period that:
    a. Establishes that upgrading the AC electric transmission corridor and meeting the goals identified in the Blueprint are transmission requirements that are being driven by public policy requirements; and
    b. Finds that the NY Transco Projects are public policy projects that meet these specified public policy requirements of New York State.

Moreover, in order to meet the 2016 to 2018 in-service dates identified in the Blueprint, the NYTOs respectfully request that the Commission establish expedited approvals for all Projects whether they require an Article VII Certificate, an updated EM&CP, or other approvals.

Dated: January 25, 2013

Respectfully submitted,

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on November 27, 2012

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
James L. Larocca
Gregg C. Sayre

CASE 12-T-0502 - Proceeding on Motion to Examine Alternating Current Transmission Upgrades.

ORDER INSTITUTING PROCEEDING

(Issued and Effective November 30, 2012)

BY THE COMMISSION:

INTRODUCTION

Constraints on the State's electric transmission system can lead to significant congestion and contribute to higher energy costs and reliability concerns. Various studies, including those performed by the New York Independent System Operator ("NYISO") and the New York Transmission Owners ("NYTOs"), have identified the alternating current ("AC") electric transmission corridor that traverses the Mohawk Valley Region, the Capital Region, and the Lower Hudson Valley as a source of persistent congestion. The corridor includes facilities connected to Marcy, New Scotland, Leeds, and Pleasant Valley substations, and two major electrical interfaces (i.e., groups of circuits) that are often referred to as "Central East" and "UPNY/SENY." A schematic map illustrating the congested transmission corridor and the two interfaces is attached hereto as an appendix.

Upgrading this section of the transmission system has the potential to bring a number of benefits to New York's ratepayers. These include enhanced system reliability, flexibility, and efficiency, reduced environmental and health impacts,[1] increased diversity in supply, and 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. The recently-released New York Energy Highway Blueprint issued by the Governor's Energy Highway Task Force recommends upgrades to this corridor providing approximately 1,000 MW of additional transmission capacity and representing a total investment of $1 billion.[2] The Energy Highway Blueprint further suggests that some projects addressing the identified congestion issues should commence construction in 2014.

In pursuit of these important goals of congestion relief and reliability enhancement and the other ratepayer benefits described above, we institute this proceeding to solicit written public Statements of Intent from developers and transmission owners proposing projects that will increase transfer capacity through the congested transmission corridor, which includes the Central East and UPNY/SENY interfaces as described above, and meet the objectives of the Energy Highway Blueprint. Sponsors of proposals that will require

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[1] Increasing the transmission capacity into high load areas downstate is expected to reduce nitrogen oxide ("NO_x") and other emissions contributing to the area's designation as "nonattainment" under the federal air quality standard for ozone.

[2] The New York Energy Highway Blueprint was issued in October 2012 and is available at http://www.nyenergyhighway.com/Blueprint.html.

certification from this Commission under Article VII of the Public Service Law should provide a schedule for the submission of a complete application. We also invite developers and transmission owners contemplating alternative transmission facilities that meet our objectives but do not require Article VII Certificates to submit Statements of Intent and schedules for the submission of any necessary permit applications. All Statements of Intent must be filed with the Secretary of the Public Service Commission electronically by January 25, 2013.

Following submission of Statements of Intent, Staff will undertake a multi-agency review and evaluation process to develop a structure and deadlines for making project-specific determinations. We expect Staff to consider whether phased reviews, perhaps on an interface by interface approach, will maximize the overall benefits to the public. We further direct Staff to perform coordinated hearings on a joint record wherever such an approach is likely to facilitate timely decision-making.

Statements of Intent should include the following:

(a) The respondent’s name, address, and primary contact information including telephone number and e-mail address;
(b) A project description, including geographic location, bulk electric system location, proposed interconnection points, and transmission capability in energy and capacity;
(c) A concise discussion of the project’s compatibility with the goals and benefits identified in this order;
(d) The projected in-service date and project development schedule including an estimate of the time needed to prepare and submit applications for any regulatory approvals necessary to begin construction;
(e) An identification of the general financial structure supporting the project and funding options, including whether the project would be supported by rates set under

our jurisdiction, Federal Energy Regulatory Commission rates, or in some other manner;

(f) A statement of the NYISO interconnection study status of the project;

(g) An identification of the extent to which the project would utilize existing rights-of-way and/or previously disturbed land; and

(h) Preliminary cost estimates for the project.

Following Staff’s review of the proposals submitted in accordance with this order, and upon consideration of Staff’s recommendations as to procedural matters, we will institute further proceedings under Article VII or other applicable provisions of the Public Service Law in order to make project-specific determinations. To the extent joint proceedings or combined records may be appropriate, we will undertake them.

TECHNICAL CONFERENCE

The Department of Public Service will host a public technical conference on December 17, 2012, commencing at 10:30 a.m. at the Department's offices at 3 Empire State Plaza, 19th Floor Board Room, Albany, New York, to provide technical assistance to potential developers and transmission owners contemplating the submittal of Statements of Intent.

The Commission orders:

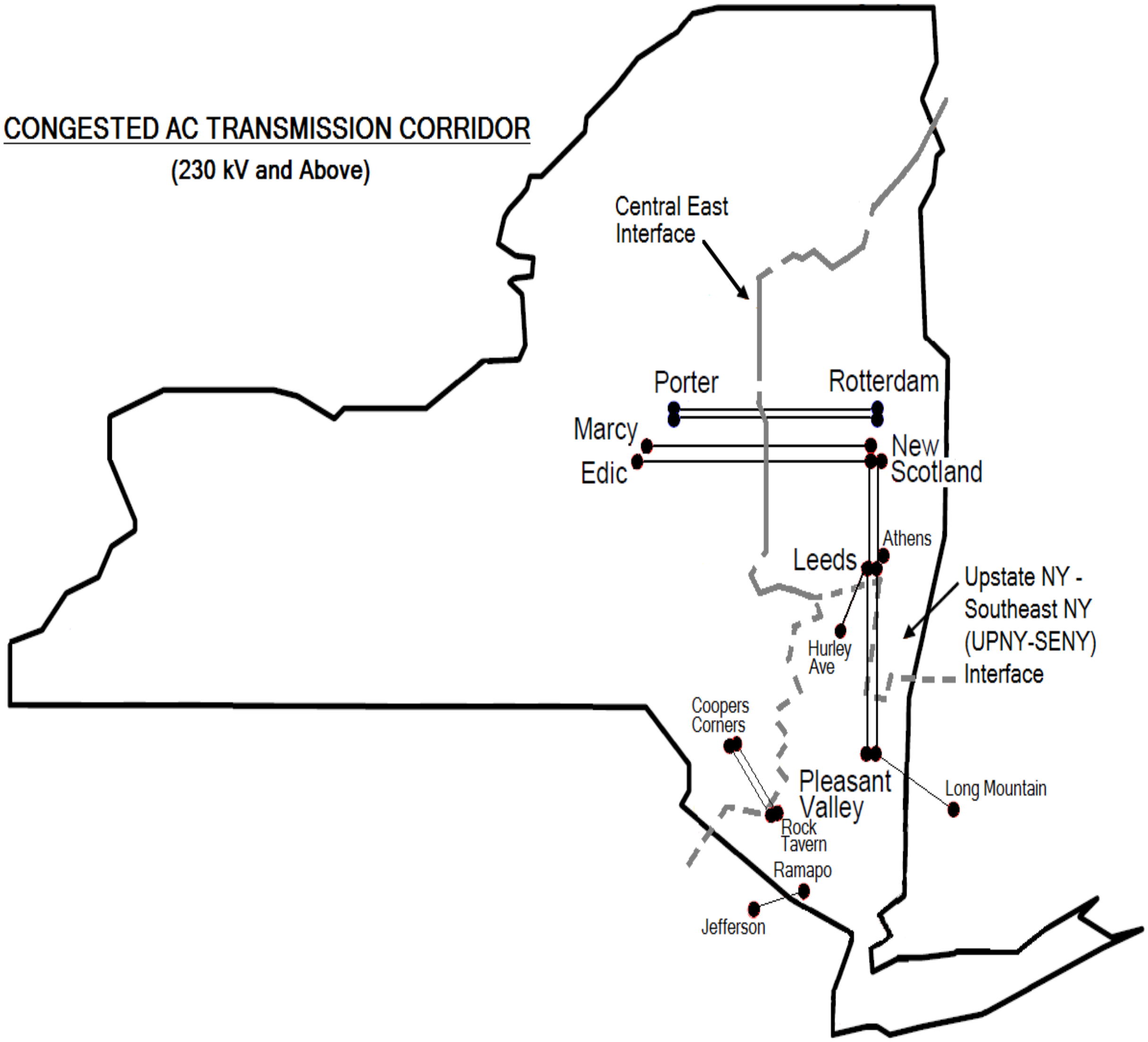
1. A proceeding is instituted to examine proposals that meet the congestion reduction objectives set forth in this Order.

2. This proceeding is continued.

By the Commission,

(SIGNED)

JACLYN A. BRILLING
Secretary


CONGESTED AC TRANSMISSION CORRIDOR
(230 kV and Above)
Central East
Interface
Porter
Rotterdam
Marcy
Edic
New
Scotland
Athens
Leeds
Hurley
Ave
Upstate NY -
Southeast NY
(UPNY-SENY)
Interface
Coopers
Corners
Pleasant
Valley
Rock
Tavern
Long Mountain
Ramapo
Jefferson

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on April 18, 2013

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
James L. Larocca
Gregg C. Sayre

CASE 12-T-0502 - Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades.

ORDER ESTABLISHING PROCEDURES FOR JOINT REVIEW UNDER ARTICLE VII OF THE PUBLIC SERVICE LAW AND APPROVING RULE CHANGES

(Issued and Effective April 22, 2013)

BY THE COMMISSION:

BACKGROUND

We instituted this proceeding in November 2012 in order to examine possible solutions to the problem of persistent congestion on portions of the New York State transmission system.[1] The focus of the proceeding is on alternating current (AC) projects and the UPNY/SENY and Central East transmission interfaces.[2] As we identified in undertaking this effort, upgrading this section of the transmission system has the potential to bring a number of benefits to New York's ratepayers. These include the near-term benefits of enhanced

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[1] Case 12-T-0502, Order Instituting Proceeding (issued November 30, 2012)(the November Order).

[2] Id. at 1-2. Specifically, we identified a need for an additional 1,000 MW of transmission capacity in this corridor.

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. A number of interested parties offered proposals intended to address these objectives. Following the instruction we gave in the November Order, Department of Public Service Staff (Staff) reviewed those submissions with the goal of developing a recommendation for managing further project-specific evaluations.

This order: (1) establishes procedures for a comparative evaluation on a common record of proposed AC project applications to be filed pursuant to Article VII of the Public Service Law (PSL); (2) adopts modifications to the regulations at 16 NYCRR Parts 85, 86, and 88; and, (3) outlines additional steps that we will take over the next several months to pursue the objectives set forth in the November Order.

DESCRIPTION OF THE PROPOSED PROJECTS

The November Order invited developers to file statements of intent (SOI) describing their proposals for congestion relief. Six developers responded with a total of 16 different projects utilizing three major transmission corridors across the state.[3] Below is a short description of the projects identified in the SOIs.

[3] While the November 30 Order specified the Marcy-New Scotland-Leeds-Pleasant Valley corridor crossing the Central East and UPNY/SENY interfaces for increased transfer capacity, the actual projects do not necessarily have to be within this corridor to accomplish the goal.

1. Boundless Energy NE, LLC

Boundless Energy NE, LLC (Boundless) proposes four projects, two AC and two direct current (DC).

a. North-South Solution

The North-South Solution is a five component project consisting of: a) interconnection of the Empire generation plant to New Scotland; b) installation of a new 345 kV line from Knickerbocker to Leeds; c) double circuiting the existing 345 kV lines from Leeds to Hurley to Roseton to Rock Tavern; d) construction of a new 345 kV cable from Roseton to a new West Fishkill Substation; and, e) construction of new twin 345 kV cables from Ramapo to South Mahwah in New Jersey.

b. West-East Solution

This proposal combines upgrading existing circuits, double circuiting, and constructing additional circuits and facilities to establish a new 345 kV path from the Niagara Area across the Southern Tier to southeast New York.

c. North River Express DC Solution

This proposal involves construction of a new 1,100 to 1,600 MW High Voltage Direct Current (HVDC) line from either Bowline or Ramapo to E. 13th Street in New York City.

d. DC Cable Conversion

This is a conversion of existing AC circuits from the Westchester area (Bowline, Indian Point or Sprainbrook and Dunwoodie) to Con Edison and LIPA to HVDC Voltage-Sourced Converter circuits.

2. Cricket Valley Energy Center, LLC

Cricket Valley Energy Center, LLC (Cricket Valley) submitted an SOI for a new 345 kV circuit from its proposed generation facility to Pleasant Valley.

3. New York Transmission Company[4]

A group of New York utilities proposed five separate transmission projects to accomplish the requested transfer capability increase. These projects include: a) the addition of series compensation on the Marcy South 345 kV lines in combination with the reconductoring of the Fraser-Coopers Corners section of the Marcy South facilities; b) construction of a second Ramapo-Rock Tavern 345 kV line; c) UPNY/SENY Interface Upgrade consisting of a third New Scotland-Leeds-Pleasant Valley 345 kV line; d) construction of a second Oakdale-Fraser 345 kV line; and, e) Marcy-New Scotland 345 kV line.

4. NextEra Energy Transmission, LLC

NextEra Energy Transmission, LLC (NextEra) has proposed three projects comprising an AC and a DC alternative. The AC proposal consists of: a) construction of a new Marcy-Princetown-New Scotland 345 kV line; and, b) construction of a new New Scotland-Leeds-Pleasant Valley 345 kV line. The DC proposal is to construct a new 320 kV HVDC facility between Marcy and either Roseton or Buchanan.

5. North America Transmission, LLC

North America Transmission, LLC (NAT), an affiliate of LS Power, proposed both a long-term solution and an interim project that could provide increased capacity in a shorter time frame. It proposes to: a) construct a new Edic-Fraser 345 kV line with series compensation; and, b) add phase angle

[4] The New York transmission owners indicate that they intend to pursue these proposals through a separate entity, New York Transmission Company (Transco). This proceeding is focused on project proposals. We express no view on the Transco concept, as it is not before us in this proceeding.

regulators on the Leeds-Pleasant Valley and Athens-Pleasant Valley 345 kV lines.

6. West Point Partners, LLC

West Point Partners, LLC has proposed the construction of a new Leeds-Buchanan North 320 kV HVDC line.

GENERAL OBSERVATIONS

Following submission of the SOIs, Staff requested the New York Independent System Operator (NYISO) to perform a high-level screening analysis to determine if portfolios of project proposals would accomplish the goal of increasing transfer capability by 1,000 MW at the UPNY/SENY interface along with an increase in transfer capability across the Central-East interface. Portfolios included grouping the Transco projects together, the Boundless North-South solution project set, the Boundless West-East solution set, the two NextEra AC proposals, and a portfolio suggested by NAT.[5] That screening analysis suggests that West-East Southern Tier transmission corridor upgrades are not likely to produce the increases in transfer capability sought in this proceeding. However, the screening analysis also indicates that combinations of the proposed projects in the two main corridors consisting roughly of the Marcy South area and the Hudson Valley are likely to provide substantial congestion relief.

The variety of project proposals suggests that there may be different approaches to increasing the transfer capacity of the system at the two interfaces of concern. It is possible that one set of projects may provide more congestion relief than

[5] Staff looked at a subset of the possible combinations of projects; the groupings discussed here do not represent an exhaustive list or preclude us from considering other possibilities.

another; it may be possible to identify an optimum portfolio of projects that provides the most benefit at the least cost to ratepayers. That portfolio may consist of projects currently being proposed by one developer, or it may involve projects sponsored by different entities. We also note that the sponsors of the proposals include new entrants, some of whom are independent transmission developers. Finally, the SOIs submitted suggest the additional possibility that some projects may be more cost-effective than others.

Given these features of the SOI submissions, we find that this case offers an opportunity to evaluate competing solutions to the transmission congestion that we have identified. We believe the interests of ratepayers would be served by reviewing and comparing the individual proposals on a combined record; this approach will allow us to determine which configuration would achieve the best balance among the objectives of reducing congestion, ensuring future reliability, and contributing to flexible system operation while minimizing environmental impacts and costs to ratepayers.[6] To accomplish this, we propose to conduct the Article VII proceeding as a coordinated and comparative review of these AC transmission

[6] For an example of an Article VII case handled on a combined record, see Case 02-M-0132, In the Matter of the Siting of Electric Transmission Facilities proposed to be located at the West 49th Street Substation of Consolidated Edison Company, Inc. et al., Notice of Combined Siting Proceeding (issued February 6, 2002).

project proposals.[7] For purposes of this order, we sometimes refer to this comparative review as "the Article VII proceeding."

In order to carry out our objective, this order establishes an overall structure and specific filing requirements for the Article VII proceeding. Staff's initial review of the SOIs suggests that the developers are not presently prepared to submit complete Article VII applications, and will need several months to do so. While we recognize that considerable time is needed to assemble application materials and studies, we intend to address the UPNY/SENY and Central East issues as promptly as possible.[8] We are also concerned to ensure that the review process is efficient, recognizing the number of projects, the likelihood of high public interest, and the limits on Staff resources.

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[7] We intend to maintain our focus on AC transmission projects. While DC facilities can contribute to relieving congestion, they are not well suited to accomplish the other goals that we have articulated for this effort. The AC system promotes reliability through its ability to respond to emergencies and changing conditions instantaneously. For example, the reconstruction of aging transmission infrastructure involves removing facilities from service, necessitating the remaining system to operate reliably during the construction period. Without adequate alternate paths for the energy, construction and congestion costs will increase. As DC lines are controlled paths, they do not offer this sort of flexibility. AC lines also provide flexibility for the interconnection of new generation at multiple points, which cannot be accomplished with DC facilities. Of course, if at any time any entity proposes to build a DC line, we will consider such an Article VII case in due course, but we would not consider it together with the AC project applications invited by this order, nor would we consider it pursuant to the special process set forth here.

[8] As we noted in the November Order, the Blueprint recommends constructing AC upgrades in this corridor between 2014-2018.

Our approach to the combined Article VII proceeding reflects the Commission's extensive experience with the siting of energy facilities under the PSL. That experience suggests that early consultation among Staff, the applicants, other involved agencies, and the affected communities, with the oversight of an Administrative Law Judge (ALJ), will assist all parties in creating a full record on which we will be able to make the required statutory findings. We also expect that active case management will enable us to reach decisions within a reasonable time frame.

We further note that the Legislature, in the recently-enacted Article 10 of the PSL, recognized the many benefits of pre-application consultations. The new statute expressly provides for public outreach in advance of the submission of a formal generation siting application.[9] The law also establishes a pre-application scoping phase that contemplates an applicant working with Staff, other agencies, and other interested parties to define the final scope of the study work that the applicant will undertake in support of the application.[10] While Article 10 does not apply to this proceeding, we believe its focus on early interaction with the public and affected communities is instructive. We also note that Article VII of the PSL reflects the same concerns for facilitating substantive public involvement in the transmission siting process.

For these reasons, we will implement a two-step application process that provides an opportunity for scoping consultations with affected communities, agencies, and other parties. AC transmission developers who are interested in participating in the comparative review proceeding are required

[9] PSL §163(3).

[10] Id. at §§163(1) and (5).

to file initial application materials, a scoping document, and a proposed schedule on or before October 1, 2013. The initial application materials that are to be provided at the first step in the process are identified in Appendix A; they consist of elements of the information specified in our regulations to comply with the statute's application requirements.[11] The scoping document should set forth the additional work that the applicant intends to undertake in order to complete the application in accordance with the regulations and the statute. Finally, the applicant should propose a schedule for completion of the activities and studies included in the scoping document.

We will require developers to satisfy Section 122(2) of the PSL and provide proof of service and notice as required by that section, on or before October 1, 2013.[12] We believe early notice to affected communities is important to the design of a project. We strongly encourage developers to engage with local governments in communities that may be impacted by their projects before the October 1 date, so that the initial application materials reflect consideration of any concerns raised by those parties. In particular, developers should make diligent efforts to identify and avoid or minimize impacts on areas of concern identified through this early outreach.

The Office of Hearings and Alternative Dispute Resolution will assign an administrative law judge (ALJ) to oversee the scoping process and set a schedule based on the proposals of applicants, Staff, other agencies, and representatives of local governments. To ensure meaningful

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[11] As modified in this order; see infra at Appendix B.

[12] Developers need only serve the initial application materials at this time. Service of remaining application materials will be accomplished in accordance with the schedule set by the ALJ.

participation in the scoping phase, we will also require developers to submit the appropriate intervenor funding fee as required by PSL Section 122(5)(a) with the initial application materials. The ALJ will administer and award intervenor funds as provided in the statute and regulations. The primary aim of the scoping phase will be to make sure that the proposed scopes meet the requirements of Article VII. The second goal will be to establish an overall schedule for the balance of the proceeding, including a common deadline for completion of the individual applications. We encourage the ALJ to consider procedural measures, such as consolidation or sequencing of issues that may streamline the decisional process. Once the applications have been found to be compliant, the ALJ shall convene hearings and other proceedings in accordance with the statute and the schedule.

Each application should be filed as an Article VII case with its own case number. We will hear all these applications on a common record, recognizing that efficiency and consistency suggest making generic determinations on common issues whenever possible, and that the comparative evaluation aspects will require a coordinated review. Specific procedures will be determined by the ALJ in consultation with parties. The ALJ should ensure it is clear which decisions are commonly applicable and which apply only to a specified case or applicant.

As we are proposing a new comparative analysis using existing authorities, we expect prospective applicants and other parties will have numerous questions about the process. We also anticipate that Staff will benefit from discussions with potential applicants and other interested parties. Therefore, we direct Staff to convene at least one technical conference, to be held within 30 days of the date of this order. We further encourage Staff to hold additional conferences as may be needed to assist prospective applicants and other parties.

ADOPTION OF MODIFICATIONS TO 16 NYCRR

In order to implement the Commission's directives in this proceeding, Staff proposed limited waivers and modifications to the Article VII regulations that would be applied in the Article VII review of AC transmission proposals submitted pursuant to this Order. The primary goal of the Staff proposal was to ensure that any such application contains pertinent information to assist the Commission to decide, in an expeditious manner, whether to grant a Certificate of Environmental Compatibility and Public Need. The rule changes proposed (modifications to 16 NYCRR Subpart 85-2 and Parts 86 and 88) would streamline the certification process by (1) avoiding the need for future applicants to seek case-specific routine waivers, and (2) clarifying certain information requirements in the existing regulations.

By a notice issued February 7, 2013, the Acting Secretary solicited comments on the Staff proposal. The notice specified a deadline for the receipt of comments of April 8, 2013, but encouraged early submission. Notice of Staff's proposal was also published in the State Register on February 20, 2013, in conformance with State Administrative Procedure Act (SAPA) Section 202(1). Comments regarding the proposal were received from three entities within the comment period, which expired on April 8, 2013.[13] Some commenters suggested changes that are within the scope of Staff's proposal. Commenters also urged that consideration be given to matters that go beyond Staff's proposal. This order discusses the

[13] Transco, Cricket Valley, and NextEra.

suggested modifications to Staff's proposal but leaves for future consideration those ideas that go beyond it.[14]

The New York transmission owners requested clarification as to which NYISO map should be used to comply with 16 NYCRR §86.3(a)(2). The rule will be clarified to specify that the required map is the New York Control Area Transmission 230 kV and above figure. These entities also commented that the 16 NYCRR §86.8 requirement would be better satisfied if the zoning and flood zones were required to be overlaid on the required topographic maps at a scale of 1:24,000. We agree with this suggestion and adopt it.

The same parties argued that the requirement to provide a statement concerning an applicant's consultation with municipalities along a project route should be met after the filing of the application or that a time limit for a municipality's response should be imposed. As discussed above, however, we strongly encourage project developers to consult with communities that may be affected by their projects, and the rule simply requires a statement describing such consultation. The transmission owners opined that the requirement that the applicant identify the agency qualified by the Secretary of State to approve building plans, inspect construction work, and certify code compliance should be removed. However, we find this requirement is necessary, because the Department of Public

[14] See infra at 13.

Service is not so qualified.[15] Last, these parties asserted that the requirement that the applicant state the criteria in a zoning ordinance or other local law by which qualification for a special exception is to be determined is inconsistent with PSL §§126(1)(f)and 130. We disagree with this view, as the Commission explained 20 years ago.[16]

We will adopt the proposed modifications for purposes of the Article VII proceeding, as discussed herein. The full text of the modified rules is attached to this order as Appendix B.

FURTHER PROCEDURAL MATTERS

We anticipate that other changes to the Article VII regulations may be necessary in order to facilitate a comparative evaluation of multiple projects on a common record. We may consider specific community outreach efforts to ensure robust public participation. We also expect to require financial information not typically submitted in an Article VII case, for the reasons discussed below. We direct Staff to prepare a proposal addressing these, and any other procedural issues Staff identifies, for publication pursuant to the SAPA by the end of May 2013. In preparing this proposal, Staff should consider suggestions for procedural adaptations made at the

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[15] 10-T-0350, DMP New York, Inc. and Laser Northeast Gathering Company, LLC, Order Granting Certificate of Environmental Compatibility and Public Need (issued February 22, 2011); and Cases 11-T-0401 and 12-G-0214, Bluestone Gas, One Commissioner Order by Garry A. Brown, Chairman, Adopting the Terms of a Joint Proposal and Granting Certificate of Environmental Compatibility and Public Need and Certificate of Public Convenience and Necessity (issued September 21, 2012)(confirmed by order issued October 18, 2012).

[16] Cases 92-T-0114, and 92-T-0252, Niagara Mohawk Power Corporation, Opinion NO. 93-17, 1993 NYPUC LEXIS 25, 33 NYPSC 885 (issued August 20, 1993).

technical conference as well as the prior transmission owner comments not addressed in this order. Our intent in setting this schedule is to ensure that any further modifications to the rules are in place well before the October 1 due date for the initial application materials.

COST RECOVERY AND COST ALLOCATION FOR AC PROJECTS

The comparative Article VII proceeding that we contemplate here will include an economic analysis of the competing proposals. We intend to issue certificates and a funding commitment to those projects, or combinations of projects, that meet the Article VII criteria and provide the most benefit to ratepayers at the least cost.[17] To achieve this, we will need to establish mechanisms for cost recovery, as the existing mechanisms for cost recovery are not designed to compensate non-incumbent developers who do not have designated customers from whom to collect their costs. We also recognize that the benefits of a project or portfolio of projects may not align with current rate structures; thus, a mechanism is needed to allocate the costs of the preferred solutions.

We anticipate that the cost allocation methodology that we will eventually apply to the successful AC projects will reflect the public policy aspects of the transmission expansion initiative. Existing Commission policies and NYISO processes only address allocation of costs for either reliability-based or “economic” projects. While the NYISO has filed a proposal at the Federal Energy Regulatory Commission to administer cost recovery and cost allocation for public policy-driven projects, it is not clear when the NYISO’s proposal will take effect, and

[17] Subject, of course, to those projects’ satisfying the criteria set forth in Article VII.

its effectiveness will depend in part on actions yet to be taken by this Commission.[18]

Given that cost allocation based on identifying the beneficiaries of a public policy initiative has not been considered before, we will undertake to examine and resolve these issues, considering the views of all potentially impacted parties. We also intend to reduce ratepayer costs and risk of cost overruns by identifying innovative cost control mechanisms, including mechanisms to share risk between project developers and customers. We direct Staff to develop a straw proposal addressing the basis for cost recovery, appropriate mechanisms for cost recovery, mechanisms for allocating risk between developers and ratepayers, and methods for allocating project costs among ratepayers. We direct Staff to make the straw proposal available for comment as soon as possible. As with the potential procedural modifications discussed above, we intend to determine these cost-related issues prior to the October deadline for initial applications. We will apply the methodologies established through these proceedings to provide cost recovery for the projects approved through the Article VII proceeding that best meet our objectives.

As we noted above, we acknowledge that procedures exist under the NYISO’s federal tariffs for the allocation and recovery of the costs of certain kinds of transmission projects. We understand that developers may seek cost recovery under the NYISO’s procedures, and we have no objection to them doing so, provided that the costs recovered are reasonable. However, to address the possibility that the NYISO process may not be available to these projects, or to all types of project sponsor,

[18] We note that under the NYISO’s proposal, we may determine the appropriate cost allocation methodology for public policy projects.

we believe it is necessary for us to establish an alternative State cost recovery mechanism and cost allocation methodology.

CONCLUSION

The variety of project submissions and the appearance of independent transmission developers create an opportunity for consumers to reap the benefits of an enhanced AC transmission system, at a cost reflecting effective competition. For these reasons, we establish procedures and deadlines for a comparative evaluation of potential solutions to the transmission congestion we identified in the November Order.

The Commission orders:

1. AC transmission developers intending to participate in the comparative Article VII proceeding shall comply with requirements set forth in the body of this order and in Appendices A and B hereto.

2. Staff is directed to arrange the technical conference and to develop straw proposals for our future consideration, as contemplated in this order.

3. We adopt the rules proposed by Staff, with the modifications discussed here, as set forth in Appendix B.

4. This proceeding is continued.

By the Commission,

(SIGNED) JEFFREY C. COHEN
Acting Secretary

Initial Application Materials:

(1) The information required pursuant to the following sections of 16 NYCRR §§85 et seq.:

- 85-2.4 – Fund for Municipal and other Parties
- 85-2.8(a), (b), (d) and (f) – Content of Application
- 85-2.10 – Notice of Application
- 86.1 – General Requirements
- 86.2 – Exhibit 1: General Information Regarding Application
- 86.3 EXCEPT for the subsections (a)(1)(ii) and B(1)(i), (ii) and (iii) – Exhibit 2: Location of Facilities[1]
- 86.6(a) and (b) – Exhibit 5: Design Drawings
- 86.8(4)– Exhibit 7: Local Ordinances
- 88.1(a)-(d) – Exhibit E-1: Description of Proposed Transmission Line
- 88.4 – Exhibit E-4: Engineering Justification

(2) Notice that the SIS/SRIS studies are in progress (study scope accepted and work underway pursuant to a Study Agreement with the NYISO); and,

(3) A scoping statement and schedule describing how and when the applicant will comply with the following sections:

- 86.4 – Exhibit 3: Alternatives
- 86.5 – Exhibit 4: Environmental Impact
- 86.7 – Exhibit 6: Economic Effects of Proposed Facility
- 86.8(1), (3), (5), (6) – Exhibit 7: Local Ordinances
- 86.9 – Exhibit 8: Other Pending Filings
- 86.10 – Exhibit 9: Cost of Proposed Facility
- 88.1(e) and (f) – Exhibit E-1: Description of the Proposed Transmission Line
- 88.2 – Exhibit E-2: Other Facilities
- 88.3 – Exhibit E-3: Underground Construction
- 88.5 – Exhibit E-5: Effect on Communications
- 88.6 – Exhibit E-6: Effect of Transportation

[1] We recommend that applicants use the latest (2010 or newer) version of the USGS Topographic Edition quadrangle maps based on ca. 2010 aerial photography for the location mapping required by 86.3(a)(1). If this version is used for 86.3(a)(1), the aerial photo based exhibit required by the regulations at 86.3(b) may be submitted with Part B.

Article VII AC Transmission Rule

In furtherance of the New York Energy Highway Task Force Blueprint, the Public Service Commission has solicited proposals for transmission projects that will increase transfer capacity in the electric transmission corridor that traverses the Mohawk Valley Region, the Capital Region, and the Lower Hudson Valley.[1] Proposals meeting the objectives of the Blueprint were due by January 25, 2013. A number of proposals were submitted by the deadline, several of which will require further review pursuant to Article VII of the Public Service Law. The purpose of this proposed rule is to clarify and modify certain requirements of 16 NYCRR Subpart 85-2, and Parts 86 and 88 in order to facilitate prompt review of timely AC project applications. The modifications established under this rule will apply in the Article VII review of any AC transmission project submitted in the Article VII proceeding contemplated by the this order in Case 12-T-0502.

Applications submitted for any such AC projects must comply with the provisions of §122 of the Public Service Law; 16 NYCRR Subpart 85-2; 16 NYCRR Part 86; and 16 NYCRR Part 88, with the following modifications and substitutions:

An application must provide the information required by Sections 86.3, 86.4, and 88.4(a)(4) except that:

The applicant may substitute recent edition topographic maps (at a scale of 1:24,000) for the New York State Department of Transportation maps specified in Section 86.3(a)(1). If the application is for the overhead portion of a transmission facility, such alternative maps must show the area for at least five miles on either side of the proposed centerline; if the application concerns an underground segment, the maps must show an area of at least one mile on either side of the proposed centerline. Applications for a subaquatic facility must utilize recent edition nautical charts (published by the U.S. Department of Commerce, National Oceanic and Atmospheric Administration) depicting the location of the proposed facility. Information required by 16 NYCRR 86.3(a)(1)(i)-(ii) must be represented on such maps.

[1] Case 12-T-0502, Proceeding on Motion to Examine Alternating Current Transmission Upgrades, Order Instituting Proceeding (issued November 30, 2012).

The applicant need not meet the requirements of §86.3(a)(1)(iii), so long as the maps or charts submitted as Exhibit 2 show any geologic, historic, or scenic area, park, or wilderness listed, eligible, or nominated for listing on the state or national register of historic places within three miles on either side of the proposed centerline, for an overhead facility; or within one mile of the proposed centerline, for an underground or subaquatic segment.

The applicant may also substitute recent edition topographic maps (at a scale of 1:250,000) for the New York State Department of Transportation maps specified at §86.3(a)(2), so long as the maps show the relationship of the proposed facility to interconnected electric systems and the information required by §86.3(a)(2)(i)-(iv) is represented on the maps.

The applicant need not meet the requirements of 86.3(b)(2), so long as the aerial photographs submitted as Exhibit 2 reflect the current situation and specify the source and date of the photography.

For Exhibit 3, the applicant may use recent edition topographic maps (at a scale of 1:24,000) instead of the New York State Department of Transportation maps referenced at §86.4(b); if any alternative is subaquatic, the applicant shall use recent edition nautical charts (published by the U.S. Department of Commerce, National Oceanic and Atmospheric Administration) to show any alternative route considered.

An application must meet the requirements of 16 NYCRR Part 88, except that an application need not contain the information required by §88.4(a)(4), so long as it contains: (1) a system impact study or system reliability impact study, performed in accordance with the open access transmission tariff of the New York Independent System Operator, Inc. (NYISO); and (2) an indication as to whether the Operating Committee of the NYISO has approved the study.

In complying with 16 NYCRR §85-2.8, the applicant must include operating effects including: (a) noise of facilities and associated equipment, including: (1) for overhead transmission facilities, conductor noise due to corona effects; (2) noise associated with operation of terminal facilities including: (i) transformers; (ii) power converter facilities; and, (iii) substation facilities; (b) electromagnetic fields (1) estimates of electric field strength at facility centerline, and at offset distances from the centerline to include areas at the edge of the proposed right-of-way.

In complying with 16 NYCRR §85-2.8, the applicant must also provide a discussion of the compatibility of the proposed facility with the goals and benefits to New York's ratepayers identified in the Blueprint, including:

1) congestion relief;
2) enhanced system reliability;
3) flexibility;
4) efficiency;
5) reduced environmental impact, including greenhouse gas emission reduction;
6) health impacts;
7) increased diversity in supply; and
8) 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.

In complying with 16 NYCRR §85-2.8, the applicant must provide the development schedule for the proposed facility (including an estimate of the time needed to prepare and submit applications for any regulatory approvals necessary to begin construction).

In complying with 16 NYCRR §86.2, the applicant must include an e-mail address in providing its contact information; and for corporate applicants, identify whether the entity is incorporated under the Transportation Corporations Law.In complying with 16 NYCRR §86.3(a)(2) the applicant must include a the New York Control Area Transmission 230 kV and Above figure showing the relationship of the proposed facility to the interconnected electric system.

In complying with 16 NYCRR §86.5, the applicant must include environmental impact analyses including an assessment of impacts on ecological, land use, cultural and visual resources; land use impacts should include noise analysis and analysis of consistency with existing, planned and proposed uses and adopted land use plans; and demonstrations of consistency with Coastal Zone policies, Local Waterfront Revitalization Programs, and designated Inland Waterway areas.

In complying with 16 NYCRR §86.8, the applicant must provide:

1) A statement describing its consultation with the municipalities or other local agencies whose procedural and substantive requirements are the subject of Exhibit 7 to: (a) determine whether the applicant has correctly identified all such requirements; and, (b) to determine whether any potential request by the applicant that the Commission refuse to apply any such local substantive requirement could be obviated by design changes to the proposed facility, or otherwise;
2) An identification of the city, town, village, county, or State agency qualified by the Secretary of State that shall review and approve any applicable building plans, inspect the construction work, and certify compliance with the New York State Uniform Fire Prevention and Building Code, the Energy Conservation Construction Code of New York State, and the substantive provisions of any applicable local electrical, plumbing or building code; if no other arrangement can be made, the Department of State should be identified; the statement of identification shall include a description of any preliminary arrangement made between the applicant and the entity that shall perform the review, approval, inspection, and compliance certification, including arrangements made to pay for the costs thereof (including the costs for any consultant services necessary due to the complex nature of a component of the proposed facility);
3) (a) A summary table of all local substantive requirements required to be identified pursuant to 16 NYCRR §86.8 in two columns (listing the provisions in the first column and a discussion or other showing demonstrating the degree of compliance with the substantive provision in the second column); and, (b) copies of or links to all such local substantive requirements;
4) Recent edition topographic maps (at a scale of 1:24,000) showing the project route location with overlays showing: (a) zoning; and, (b) flood zones;
5) (a) An identification of the zoning designation or classification of all lands constituting the site of the proposed facility and a statement of the language in the zoning ordinance or local law by which it is indicated that the proposed facility is a permitted use at the proposed site; (b) if the language of the zoning ordinance or local law indicates that the proposed facility is a permitted use at the proposed site subject to the grant of a special exception, the applicant shall provide a statement of the criteria in the zoning

ordinance or local law by which qualification for such a special exception is to be determined; and,

6) (a) A list of all state approvals, consents, permits, certificates, or other conditions for the construction or operation of the proposed facility of a substantive nature; and, (b) a statement that the facility as proposed conforms to all such state substantive requirements.

In complying with 16 NYCRR §86.10, the applicant must identify the general financial structure supporting the proposed facility and funding options (including whether the project would be supported by rates set under Commission jurisdiction, under the jurisdiction of the Federal Energy Regulatory Commission, or in another specified manner. In preparing the detailed cost estimate required by §86.10, the Applicant must provide estimates of the following items: cost of interconnection facilities, including the cost of all substation work associated with new and upgrading existing substations for bus work, breakers, transformers, control houses, and other necessary equipment. Work papers supporting all cost estimates must be provided with the application.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on September 19, 2013

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Garry A. Brown
Gregg C. Sayre
Diane X. Burman

CASE 12-T-0502 - Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades.

ORDER ADOPTING ADDITIONAL PROCEDURES AND RULE CHANGES FOR REVIEW OF MULTIPLE PROJECTS UNDER ARTICLE VII OF THE PUBLIC SERVICE LAW

(Issued and Effective September 19, 2013)

BY THE COMMISSION:

BACKGROUND

The Commission instituted this proceeding in November 2012 in order to examine possible alternating current (AC) transmission solutions to the problem of persistent congestion on the UPNY/SENY and Central East transmission interfaces.[1] As we identified in undertaking this effort, upgrading this section of the State's transmission system has the potential to bring a number of benefits to New York ratepayers. These include the near-term benefits of enhanced system reliability, flexibility, and efficiency, reduced environmental and health impacts through

[1] Case 12-T-0502, Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades, Order Instituting Proceeding (issued November 30, 2012)(November Order).

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.

In April 2013, anticipating that several responsive proposals might be filed, we established procedures for a comparative evaluation of proposed AC project applications under Article VII of the Public Service Law (PSL).[2] We also adopted modifications to the regulations contained in 16 NYCRR Parts 85, 86, and 88 necessary to assist us in streamlining the certification process,[3] and outlined additional steps to be taken over the next several months to pursue the objectives set forth in the November Order. We established a two-step review process involving the submission of initial application materials, scoping documents,[4] and proposed schedules by October 1, 2013 (called "Part A" application materials), and submission of the remaining Article VII application materials (hereafter "Part B")

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[2] Case 12-T-0502, Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades, Order Establishing Procedures for Joint Review under Article VII of the Public Service Law and Approving Rule Changes (issued April 22, 2013)(the April Order). At the time, we also reiterated our intent to maintain our focus on AC transmission solutions. While other types of facilities may contribute to relieving congestion, they do not share all the characteristics of AC facilities and do not provide the same benefits.

[3] April Order at 13. The approved rule changes streamline the certification process by (1) avoiding the need to seek case-specific routine waivers, and (2) clarifying certain information requirements in the existing regulations.

[4] Scoping contemplates an applicant working with Staff, other agencies, affected communities and other interested parties to define the final scope of the study work that the applicant will undertake in support of its application.

on a schedule to be set by an Administrative Law Judge (ALJ).[5] We also advised that other rule changes might be necessary to facilitate the comparative evaluation that we envision and directed Staff to prepare a proposal identifying such changes. Accordingly, by Notice issued May 29, 2013, Staff proposed rules to be applied in the review of the applications submitted in response to this proceeding.

The primary goals of the proposed rules are to ensure that appropriate procedures are in place to enable us to make a comparative evaluation of multiple projects on a common record, and to ensure that any such application contains pertinent information so we may decide, in an expeditious manner, whether to approve a particular project(s). The proposed rule changes called for: designation of a presiding officer, non-Article VII project filing requirements, a preliminary scoping process (e.g., methodologies for studies, coordination of studies), the development of a common record for specified issues, additional application requirements, and initial public outreach.

The May 29 Notice specified a comment deadline of July 29, 2013, but encouraged early submission. Notice of Staff's proposal was also published in the State Register on June 12, 2013, in conformance with State Administrative Procedure Act Section 202(1). Comments regarding the proposal were received from five entities within the comment period, which expired on July 29, 2013.[6] Multiple Intervenors (MI) filed a petition seeking a stay of all activities in this proceeding.

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[5] April Order at 8-9.

[6] New York Transmission Company (Transco), NextEra Energy Transmission, LLC (NextEra), North America Transmission, LLC (North America), Boundless Energy NE, LLC (Boundless) and the New York State Department of Environmental Conservation (NYSDEC). Transco submitted an unsolicited response to comments on August 28, 2013.

COMMENTS AND RESPONSES

NextEra urged that we rely on the Part A application materials to pre-select those projects that will proceed to the Article VII siting analysis and recommend those selected projects to the New York Independent System Operator, Inc. (NYISO) as Public Policy Requirement projects, with only one being recommended if proposed projects overlap.[7] Similarly, North America maintained that we should conduct a comparative evaluation of proposed projects as soon as practical after the submittal of the Part A application materials. These parties opined that the early comparative evaluation approach they propose is consistent with the law, conforms to appropriate system planning, increases the possibility for real competition, and is significantly more efficient than a late comparative evaluation approach. Boundless likewise contends that an early determination of whether the proposed projects meet a need identified by the Commission would aid in expeditious resolution of the proceeding and materially support applicants' efforts to secure financial support.

These parties further argued that, should the Commission decline to adopt their recommendation to provide for an early comparative evaluation and selection, we should at least level the playing field between incumbent and non-incumbent applicants by providing for recovery of their project development costs. NextEra asked us to "authorize cost recovery

[7] In order to make this selection and recommendation, NextEra claimed that the following matters, besides scoping, issue coordination and scheduling regarding the filing of Part B application materials, should be addressed in the first phase: a. The findings required by PSL §126(1)(a) (on the basis of need) and (g) (on the public interest, convenience and necessity); b. findings as to cost and risk to ratepayers; and c. findings as to best fit to the Commission's and Energy Highway Blueprint objectives.

for planning, Article VII applications, and other development activities, subject to a prudence standard and a recovery cap of $5 million per project, recovered via contract with an incumbent transmission provider, should the developer's project ultimately not be selected." NextEra pointed out that we allowed limited development cost recovery for the Transmission Owner Transmission Solutions (TOTS) projects in Case 12-E-0503.

Noting that both the April Order and the procedural rules proposed in the May Notice refer to consideration of the proposals on a common record, Boundless urged us to clarify that the four key issues noted in the procedural rules proposed by Staff,[8] as well as the basis of the need for proposed facilities and which proposed facilities meet the policy requirements reflected in the Commission's objectives for this proceeding should be not only "addressed" but also "determined" in the common record phase of the proceeding.

Boundless further suggested that it would be important for key component segments of projects, and not just overall projects, to be addressed on a common record in detail. Otherwise, Boundless asserted, important distinctions in cost, design and benefits to the system between comparable component segments proposed by different project sponsors may be lost. At the same time, Boundless argued, the expeditious development of the common record would be threatened if non-material subprojects were included in the common record hearings. Therefore, it argued that the ALJ should be directed to identify early in the case which component segments will be addressed during the common record hearings and to make an early

[8] Minimum adverse environmental impact, public interest, cost and risk to ratepayers, and best fit to the Commission's objectives.

determination of which segments meet the Commission's focus on the congested transmission corridor.

Transco asserted that some of the information proposed for inclusion in any filings regarding non-Article VII projects due by October 1, 2013 is overly burdensome. For example, rather than requiring the filing of copies of all federal, state and local applications related to the project, Transco argued that the rule should permit applicants to provide a citation or link to such applications. In addition, Transco argued that, given that a lead agency's determination of significance and a completed Environmental Assessment Form (EAF) may not be available by October 1, the rule should only require a demonstration that the applicant has provided a copy of the Part 1 EAF to the proposed lead agency and that the siting process is underway based on a proposed commercial operation date.

NYSDEC contended that a significant issue in this proceeding concerns site access to the transmission rights-of-way (ROW) owned or controlled by incumbent utilities. NYSDEC is particularly concerned that lack of site access by some project developers will compromise preparation of application materials and assessment of potentially significant environmental and natural resource issues. According to NYSDEC, equal access to ROW and other site information will ensure that the best data is available for the Commission's decision making. Accordingly, NYSDEC urged us to exercise our authority under the PSL to require or arrange access for non-incumbent utilities to utility ROW and other related property as necessary and appropriate. NYSDEC also explained that ensuring coordination of studies among project sponsors in sensitive resource areas so as not to disturb or put undue stress on natural resources and threatened or endangered animal or plant species would be highly desirable. NextEra likewise maintained that the regulations should be amended to require that electric corporations that control existing ROW allow the proponents of other projects filing Part A application materials to have access to their ROW for purposes of conducting studies to be included in the Part B applications. In particular, NextEra asserted that the Commission has the requisite statutory authority to require the transmission owners to file plans as to how they will allow shared access to their property.

NextEra commented that 16 NYCRR §86.8 should be amended to classify transmission facilities described in Part A application materials as public utility facilities relative to the question of conformity to local substantive legal requirements that govern permissible uses and the location of such facilities. According to NextEra, this designation is important because many local ordinances treat "public utility" facilities (or similar classification) differently from non-public utility facilities for purposes of zoning use authorizations.

North America requested clarification of the proposed rule as to when landowners must be notified of proposed projects and which landowners are required to receive notice. Regarding procedures and scoping, Transco requested clarification that:

(1) The presiding officer who is tasked with establishing methods and types of studies to submit, as well as identifying any potential consolidation of issues and coordination of studies and data collection, will also be establishing a comment period during which applicants will be able to comment on the identification and coordination of relevant studies and any proposed consolidation of issues;

(2) Applicants will be given sufficient time to respond to any comments submitted by parties and the public on the draft scopes and schedules;

(3) the requirements relating to information to be included in the application with respect to property/ownership rights and the comparison of alternative locations are

not due in the October 1 filing, but are expected to be included in Part B of the application;

(4) scoping documents must be put on applicants' websites when available, with only draft scoping documents to be made available by October 1;

(5) Staff will be setting up a schedule of hearings or public information sessions, which applicants would put on their websites; and

(6) electronic filing is sufficient to meet the October 1 deadline and service of hard copy documents is not mandatory, but they will be required to be made available upon request.

NYSDEC took the opportunity afforded by the May 29, 2013 Notice to express its views on certain provisions adopted in the April Order. It stated that the rules concerning the information that is required in Part A and Part B application materials need clarification because the attempt to distinguish such information by color coding in a document posted to our Document and Matter Management System on May 28, 2013 was not entirely successful.[9] Regarding 16 NYCRR §85-2.8(d), NYSDEC requested that the requirement in paragraph (5) be revised to require "Project environmental impacts, including Air Pollution/GHG [green house gas] emissions from project construction and operation", and that a separate category be provided for "Environmental Benefits, including regional Air Pollution and GHG emission reductions."

In comments on 16 NYCRR §86.3, NYSDEC sought clarification regarding language requiring mapping of the proposed facilities and associating a variety of environmental resource locations to their "listing on the state or national register of historic places." NYSDEC also recommended that the rules in 16 NYCRR §86.4, regarding consideration of

[9] The document was posted in response to questions posed at the May 14, 2013 technical conference held by Staff.

alternatives, specifically require each applicant to respond to proposals of other applicants that compete with its proposal and purport to satisfy similar goals and objectives. Lastly, NYSDEC recommended that certain additional showings be made in Exhibit 4 regarding efforts to minimize GHG emissions related to project construction, operation and maintenance, and to address specific potential effects of climate change (including sea level change, underground facilities design considerations, severe weather conditions, storm events and floodplain location design criteria).

Transco objected to providing any mechanism for the recovery of development costs that would impose the burden of projects proposed by independent developers on utilities or their customers. It noted that, in authorizing the utilities to recover certain development costs for the TOTS projects in Case 12-E-0503, the Commission found it was reasonable to institute different cost recovery provisions for utilities and developers (because utilities have Provider of Last Resort obligations under the Public Service Law), and that it was neither necessary nor appropriate to provide identical cost recovery provisions for each.[10]

Transco further asserted that the incumbent transmission owners have provided and will continue to provide access to existing ROW to developers in a uniform and consistent manner. It argued that the utilities do so by means of policies and procedures designed, first and foremost, to protect and safeguard critical infrastructure as well as those individuals accessing utility property. Thus, Transco objected to any intervention by the Commission in this matter.

[10] Case 12-E-0503, Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans, Order Upon Review of Plan to Issue Request for Proposals (issued March 15, 2013) at 18.

MI, in its petition, sought a stay of the proceeding on various grounds. MI argued that (1) the Commission lacks authority to engage in planning and funding AC transmission solutions; (2) this proceeding interferes with the NYISO's planning activities; (3) the AC transmission initiative will impose unjust and unreasonable rates on retail customers; and (4) the Commission has no basis for focusing on AC projects.

DISCUSSION

At the outset, we deny (as a matter committed to our discretion) MI's request for a stay in this proceeding. Since the commencement of this proceeding in November 2012, we have considered and addressed these issues. Given our findings as to the persistence of congestion on the interfaces of concern, we see no reason to delay the assessment of the solutions that may be offered in this case.

On the issue of taking an early comparative evaluation approach (on the basis of Part A application materials), as advocated by some commentators, a number of benefits could attend this course of action. Moreover, we agree with them that the Commission possesses the necessary statutory authority to engage in some early screening.[11] Indeed, we might well be able to go so far as to make preliminary findings on some of the issues we are required to evaluate under PSL Article VII, such as the need for specified facilities and their conformity to a long-range plan for expansion of the electric power grid. Yet it is highly doubtful that, on the basis of only Part A application materials, we could appropriately make even preliminary determinations as to whether a given facility would serve the public interest, convenience and necessity, or which

[11] See, PSL §§4(1), 5(2), and 66(1), (2) and (5). See also, 16 NYCRR §85-2.5.

facility would best fit the Energy Highway objectives. Finally, given that we do not know how well-developed the proposed projects are, and thus cannot determine what level of risk ratepayers would assume, it is not clear what would be gained by comparing the preliminary project cost estimates.[12]

That said, however, given the efficiencies that might well be gained by screening out proposed projects that do not meet, or only minimally meet, the objectives of this proceeding, we will give the ALJ significant flexibility in presiding over the proceedings (including the authority to hold hearings pursuant to PSL §66(5), to consider requests for late submission of information pursuant to 16 NYCRR §85-2.3(c), and to decide (upon the motion of any party or sua sponte) to sever issues for separate decision, pursuant to 16 NYCRR §85-2.13).

We direct the ALJ to consider, promptly after the initial applications are filed, whether an early screening would help streamline the process and serve the goal of obtaining congestion relief at the least cost to ratepayers, and in the 2014-2018 timeframe set out in the Energy Highway Blueprint. Such a screening may be most appropriate if there are many Part A filings, raising the prospect of significant stress on Staff resources. We believe it may be possible to assess certain factors in advance of completion of the Article VII applications and thereby streamline the overall effort required to complete this undertaking. In our April Order, we approved rules for the Article VII process that include application requirements

[12] We do not mean by this statement to discourage applicants who desire to do so from providing preliminary cost estimates pursuant to 16 NYCRR §85-2.8(f).

addressing "the compatibility of the proposed facility with goals … identified in the Blueprint."[13]

We believe that an early screening on focused criteria would support the Energy Highway goals. In particular, projects that do not provide the minimum 1000 MW of increased transfer capability that we have targeted, or that have not yet commenced the NYISO study process, or whose sponsors cannot demonstrate substantial experience in the construction and operation of AC transmission lines, need not be considered as candidates for cost recovery in the comparative proceeding.[14]

A comparison of the proposals' costs to ratepayers may also provide a basis for eliminating some projects from contention. If the ALJ finds that taking this step would streamline the process and reduce impacts on Staff resources, he or she may invite bids from applicants structured in accordance with the results of our effort to establish cost recovery rules and risk-sharing principles for this proceeding.[15] To accomplish this, we note that developers must have an opportunity to marshal a level of data that is appropriate in light of the risk model we ultimately adopt. This and other factors may be used by the ALJ to conduct further screening.

The ALJ should make the results of the screening assessment(s) available to all of the parties and to the public and should take them into account when establishing further proceedings and schedules. We caution that the purpose of any

[13] In the same order, we also initiated a process to establish mechanisms for allocating risk between developers and ratepayers in the context of cost recovery and allocation. We are currently considering comments received on a Staff straw proposal on these issues, and we expect to address this subject in the near future.

[14] "Projects" may have different components that together provide the necessary relief, if they are filed by joint sponsors.

[15] See footnote 13.

screening must be to streamline the overall process. The ALJ should not attempt to quantify criteria that cannot be assessed in a reasonable time or that require extensive factual development.[16] We expect the ALJ to conduct the proceedings as efficiently and expeditiously as possible, and to exercise the flexibility we have granted with due attention to the timeframes suggested in the Blueprint. We will rely on the ALJ to issue appropriate rulings (including those regarding whether an application should be dismissed, pursuant to 16 NYCRR §85-2.15, if it appears that the statutory requirements for a Certificate cannot be met).

In view of the foregoing discussion, we do not find it necessary to decide now how (if at all) to level the playing field between incumbent and non-incumbent electric corporations. An independent developer has no obligation to incur development costs but may see a future opportunity as worth the near-term risk. The screening we have authorized here will provide applicants with some indication of their likelihood of success. In any event, we decline to address here the question of how the recovery of development costs would be afforded to non-incumbent utilities.

To clarify the flexibility given to the ALJ to fashion appropriate procedures, based on input from the parties, we take this opportunity to modify slightly the rule proposed in the May 29 Notice. In the proposed rule, Staff wrote, “The presiding officer shall organize the parties’ presentations to allow for application specific and comparative findings. The findings required by Section 126(1)(a), (b), (d), and (f) of the Public Service Law (PSL) shall be made on an individual record for each

[16] We anticipate that the ALJ will be able to call on the expertise of the NYISO in assessing the degree of additional transfer capability offered by the projects described in Part A application materials submitted by October 1, 2013.

proposed Article VII transmission line." The proposed rule goes on to specify the findings that would be made on a comparative basis. We agree with the division of findings that should be made for each proposed line and those that will be made on a comparative basis. We clarify, however, that the findings to be made for each proposed project need not necessarily be made "on an individual record." Rather, the ALJ and the parties should feel free to develop a common record for findings on individual projects where it makes sense to do so; for example, in determining the environmental impacts of projects that share the same proposed route.

As for the information that proponents of non-Article VII projects must file by October 1, we agree with Transco that such applications may include electronic links to, rather than copies of, all federal, state, and local applications associated with such proposed projects. We also note that the proposed rule was not intended to require documents that are unavailable as of the October 1 deadline. At a minimum, however, a copy of the Part 1 EAF should be included, together with a statement as to the status of the review under the State Environmental Quality Review Act (Article 8 of the Environmental Conservation Law).

NYSDEC is correct that, in order for the comparative project evaluation we are embarking on to be successful, non-incumbent electric corporations must have appropriate access to the transmission ROW of incumbent utilities. We also agree with NYSDEC that ensuring coordination of project-related studies among utility personnel and consultants will appropriately minimize any adverse environmental impact related to the conduct of necessary studies. In accordance with PSL §§ 4(1), 5(2) and 66(1), we will therefore require electric corporations that control existing ROW to allow parties filing Part A application materials to have reasonable access to those portions of the electric corporation ROW that are the subject of those applications. The electric corporations should give applicants access for purposes of conducting studies needed to complete their applications and for purposes of preparing cost estimates, subject only to such reasonable requirements as the utilities routinely specify when they provide such access to contractors and other persons who need to gain access to their ROW.[17] To aid the ALJ in resolving disputes as to ROW access or study coordination, we will require those electric corporations controlling transmission ROW to file, by October 1, 2013 (or such later date as may be specified by an ALJ) their currently effective policies and procedures for ROW access.[18]

We cannot grant NextEra's request that we amend 16 NYCRR §86.8 to classify transmission facilities described in Part A application materials as public utility facilities for purposes of our decision as to whether such facilities conform to applicable local substantive legal requirements. We confirm that these facilities, once constructed, will be electric plant owned by electric corporations under the Public Service Law, but we will not here attempt to interpret local ordinances. Moreover, the observation of the New York State Board on Electric Generation Siting and the Environment with respect to PSL Article 10 that "the statute requires that local governments be given an opportunity to defend their specific laws before the

[17] Obviously, if a project is eliminated as part of an early screening process, nothing in this order would obligate an electric corporation to provide access to the developer of that project after that point.

[18] We emphasize that arrangements for access to the ROW should be made before the October 1 filing date; the filing of the policies and procedures may be helpful in resolving any disputes that may arise.

matter can be considered ..."[19] is equally applicable to PSL Article VII.

We turn next to the requested clarifications of the rules proposed on May 29, 2013. Regarding the clarification sought by North America and Transco, the proposed rule required notification of owners of any land an applicant believes to be necessary for construction, operation and maintenance of its proposed project before the Secretary may determine that its application complies with applicable filing requirements, which may only occur following the filing of the Part B application materials. Thus, these notifications must be made before the deadline set by the ALJ for Part B.

Concerning the other clarifications requested by Transco, the ALJ will undoubtedly establish appropriate methods for receiving the input of parties on the matters left to the care of the Office of Hearings and Alternative Dispute Resolution. It is obvious moreover, that final scoping documents (and other documents not available by a particular deadline) need not be put on an applicant's website until they are available. As for the method of filing of the Part A application materials, we will require electronic filing by October 1, with seven hard copies to be provided to Staff as soon as possible thereafter (but not later than October 7), with

[19] Case 12-F-0036, In the Matter of the Rules and Regulations of the Board on Electric generation Siting and the Environment, Contained in 16 NYCRR Chapter X, Certification of Major Electric Generating Facilities, Memorandum and Resolution Adopting Article 10 Regulations (issued July 17, 2012) at 78.

hard copies being provided to other parties to the proceeding in which the Part A application materials were filed upon request.[20]

We take this opportunity (at NYSDEC's suggestion) to enhance the rules adopted in our April Order. We note that the color coding in the guidance document was intended to highlight the Part A filing requirements--those topics that are to be initially addressed in the Part A scoping schedule, and fully addressed with supporting analyses in Part B application filings. The rule specifying that, in complying with 16 NYCRR §85-2.8, an applicant must provide the development schedule for the proposed facility (including an estimate of the time needed to prepare and submit applications for any regulatory approvals necessary to begin construction) must be complied with in Part A application materials. Other requirements referencing §85-2.8 need not be complied with until Part B application materials are filed, though applicants would do well to discuss in their Part A application filings the compatibility of their proposed facilities with the goals and benefits to New York's ratepayers identified in the Energy Highway Blueprint, pursuant to 16 NYCRR §85-2.8(f).

While the rules adopted in the April Order did not acknowledge that potential increases in impacts may occur from certain aspects of project construction or system operation, we will adopt NYSDEC's suggestion that the rule requiring a discussion of reduced environmental impact, including GHG emission reduction, be revised to require "Project environmental impacts, including Air Pollution/GHG emissions from project construction and operation", and that a separate category be

[20] As part of electronic filing of Part A materials, applicants shall submit proposed facility and right-of-way locational maps, and file location information in Geographic Information System Esri shapefile format using coordinate system NAD 1983 UTM Zone 18N.

provided for "Environmental Benefits, including regional Air Pollution and GHG emission reductions."

To clarify requirements concerning 16 NYCRR §86.3, we will revise the text as follows: "The applicant need not meet this requirement, so long as the maps or charts submitted as Exhibit 2 show any geologic, historic resource listed on the state or national register of historic places, or scenic area, park, or wilderness within three miles on either side of the proposed centerline, for an overhead facility; or within one mile of the proposed centerline for an underground or sub-aquatic segment." As for NYSDEC's comment that the requirement in 16 NYCRR §86.4, regarding consideration of alternatives, should specify that applicants must respond to competing proposals of other applicants that purport to satisfy similar goals and objectives, we expect that such would be the case in the normal course of evidentiary hearings and pleadings; we will not, however, require that all applicants address all competing proposals as part of their applications.

Finally, NYSDEC is correct that showings concerning design and mitigation measures should be made in Exhibit 4 of applications. Accordingly, we adopt the following requirements as additions to the required discussion in 16 NYCRR §86.5:

(1) What efforts, if any, have been made to minimize the emissions of greenhouse gases during the construction, operation and maintenance of the proposed facility;

(2) If any portion of the proposed facility is to be constructed underground, the applicant shall state what, if any, plans have been made to ensure system resilience to rising water tables, including potential salt water intrusion in coastal areas;

(3) If any portion of the proposed facility is to be constructed in the 0.2 (1 in 500 year storm) percent floodplain, the applicant shall state what, if any, plans have been made to ensure system

resilience to flooding, including enhanced storm surge in coastal areas;

(4) What, if any, plans have been formulated to ensure that the proposed facility is resilient to severe snow and/or icestorms; and

(5) What, if any, plans have been formulated to ensure that the proposed facility is resilient to periods of extreme heat.

The enhancements to the substantive rules that applicants must comply with in providing Part A application materials are included in Appendix A hereto.

CONCLUSION

The comments submitted in this proceeding have greatly assisted us in formulating procedural and substantive rules for use in evaluating the several proposed facilities expected to be described in Part A application materials by October 1, 2013. We therefore adopt the provisions discussed herein for a comparative evaluation of potential solutions to the transmission congestion we identified in the November Order.

The Commission orders:

1. The petition for a stay of all activities in this proceeding filed by Multiple Intervenors on September 4, 2013 is denied.

2. AC transmission developers intending to participate in the proceedings initiated on or after October 1, 2013 shall comply with the procedural and substantive rules described in the body of this order and in Appendix A hereto.

3. Electric corporations who participate in the proceedings contemplated here shall provide access to their owned or controlled ROW as required by this order.

4. This proceeding is continued.

By the Commission,

KATHLEEN H. BURGESS
Secretary

APPENDIX A

Case 12-T-0502

Article VII Part A Template

1. Article VII application must include:
    a. Payment for Intervenor Fund (85-2.4):
    b. Application content (85-2.8(a), (b), (d) and (f)):
        i. Proposed Facility (85-2.8)
            1. a description of the proposed facility,
            2. location of proposed facility or right-of-way,
            3. explanation of need for the proposed facility, and
        ii. such other information as the applicant deems necessary or desirable.
    c. Notice of Application, newspaper publication and proof of service (85-2.10)
    d. General requirements for each exhibit (86.1)
    e. Exhibit 1: General Information Regarding Application (86.2): Two additional requirements:
        i. applicant must include an e-mail address with applicant's contact information.
        ii. corporate applicant must identify whether it is incorporated under the Transportation Corporation Law.
    f. Exhibit 2: Location of Facilities (86.3)(a)(1): Detailed maps, drawings and explanations showing the ROW,[1] including GIS shapefiles of facility locations and:
        i. NYSDOT 1:24,000 topographic edition showing:
            1. proposed ROW (indicating control points) covering an area of at least 5 miles on either side of the proposed centerline.

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[1] Aerial photo requirement (86.3(b)) shifts to Part B as long as applicant uses 2010 or newer USGS topo for 1:24,000 mapping required by 86.3(a)(1).

2. geologic, historic resources listed on the state or national register of historic places, or scenic area, park, or wilderness within three miles on either side of the proposed centerline for an overhead facility; or within one mile of the proposed centerline for an underground or sub-aquatic segment.

ii. (86.3)(a)(2) – NYSDOT 1:250,000 scale or other recent edition topographic maps showing the relationship of the proposed facility to the applicant's overall system, with respect to:

1. the location, length and capacity of the proposed facility, and of any existing appurtenances related to the proposed facility.

2. the location and function of any structure to be built on, or adjacent to, the right-of-way (including switchyards; substations; series compensation station facilities; microwave towers or other major system communications facilities; etc.)

3. the location and designation of each point of connection between an existing and proposed facility, and

4. nearby, crossing or connecting rights-of-way or facilities of other utilities.

g. Exhibit 5: Design Drawings (86.6(a) and (b)): design, profile and architectural drawings and descriptions of proposed facility, including:

i. the length, width and height of any structure, and

ii. the material of construction, color and finish

h. Exhibit 7: Local Ordinances (86.8(4)):[2] Recent edition 1:24,000 topos with overlays showing:

i. zoning; and

[2] Applicants are encouraged to show zoning districts as overlays on 1:24,000 scale topo maps, but may use other appropriate mapping that clearly relates the proposed facilities locations to zoning district maps.

    ii. flood zones (include 100 year (1%) and 500 year (0.2%) flood hazard areas, and floodway locations, as available)

i. Exhibit E-1: Description of Proposed Transmission Line (88.1(a)-(d)): detailed description of proposed line, including:

    i. design voltage and voltage of initial operation
    ii. type, size, number and materials of conductors
    iii. insulator design
    iv. length of the transmission line

j. Exhibit E-4: Engineering Justification (88.4)and new section of 85-2.8 addressing compatibility of the facility with the goals and benefits to New York's ratepayers identified in the Blueprint:

    i. summary of engineering justification for proposed line, showing its relation to applicant's existing facilities and the interconnected network, with full justification to be submitted in Part B;
    ii. summary of anticipated benefits with respect to reliability and economy to applicant and interconnected network. Specific benefits to be submitted in Part B;
    iii. proposed completion date, and impact on applicant's systems and of others' of failure to complete on such date;
    iv. appropriate system studies (see SIS notice requirement below);
    v. a general demonstration of how, and to what extent, the proposed transmission project meets the congestion relief, system reliability, reduction in regional air pollution and greenhouse gas emissions and the other benefits and objectives identified by the Commission in Case 12-T-0502; details of this demonstration shall be provided with Part B filing, along with the results of the NYISO studies required by 16 NYCRR 88.4 (a)(4);

k. Pre-Filed direct testimony of applicant's witnesses supporting Part A exhibits

2. Notice that the SIS/SRIS studies are in progress (study scope accepted and work underway pursuant to a Study Agreement with the NYISO); and
3. Scoping statement and schedule: Describing how and when the applicant will produce the exhibits required for the Part B filing:

   i. Exhibit 3 (86.4): Alternatives: applicant may use recent edition topographic maps (1:24,000). If any alternative is sub aquatic, applicant should use recent edition nautical charts to show any alternative route considered.(86.4)

   ii. Exhibit 4 (86.5): Environmental Impact must include: assessment of impacts on ecological, land use, cultural and visual resources; noise analysis; coastal zone consistency (including local waterfront revitalization programs and designated inland waterway areas); efforts, if any, to minimize the emissions of greenhouse gases during the construction, operation and maintenance of the proposed facility; plans to ensure facility resilience to rising water tables, flooding, ice storms, coastal storm surges, and extreme heat.

   iii. Exhibit 6 (86.7): Economic Effects of Proposed Facility

   iv. Exhibit 7(86.8 (1),(3),(5) and (6): Local Ordinances where Facility modifications being made, including statement of consultations with municipalities and local agencies, summary table of all substantive requirements, zoning designation or classification, and list of regulatory approvals.

   v. Exhibit 8(86.9): Other Pending Filings

   vi. Exhibit 9(86.10): Cost of Proposed Facility modifications.

   vii. Exhibit E-1 (88.1(e)(f)): Facility Description

   viii. Exhibit E-2 (88.2): Other Facilities

   ix. Exhibit E-3 (88.3): Underground Construction

   x. Exhibit E-5 (88.5): Effect on Communications

xi. Exhibit E-6 (88.6): Effect on Transportation

a. Notice of Application and proof of notice and service (85-2.10)

Part A Initial Applications for projects that are not subject to Article VII must include:

1. Links to the full text and figures of all applications submitted to any state, local or federal agency related to the proposed project.
2. A list of the permits and approvals that the project sponsor is required to obtain for the construction and operation of the project, and a schedule for the submission of any applications or other filings not provided under item 1.
3. Where a lead agency has been identified and has made a determination of significance pursuant to SEQRA, a copy of the lead agency's determination.
4. A copy of the EAF reviewed by the lead agency in making its determination, or, if a determination has not been made, a copy of the Part 1 EAF submitted to the involved agency or agencies.
5. If the lead agency's determination of significance was positive, a schedule for the preparation and submission of a DEIS or a copy of the DEIS submitted to the lead agency.
6. If an applicant has yet to receive the lead agency's determination, a description of the status of the SEQRA review (including a proposed schedule for preparation and submission of a DEIS, assuming the determination will be positive).
7. A demonstration of how and to what extent the proposed project meets the congestion relief objectives identified by the PSC in Case 12-T-0502.

2012 Reliability Needs Assessment

New York Independent System Operator

FINAL REPORT

September 18, 2012

4.3.2 Indian Point Plant Retirement Scenario

Reliability violations of transmission security and resource adequacy criteria would occur in 2016 if the Indian Point Plant were to be retired by the end of 2015 (the latter of the current license expiration dates) using the Base Case load forecast assumptions.

The Indian Point Plant has two base-load units (2060 MW) 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 in the Base Case and Econometric Forecast Scenario. Southeastern New York, with the Indian Point Plant in service, currently relies on transfers to augment existing capacity, and load growth or loss of generation capacity in this area would aggravate those transfer limits.

Transmission security analysis (N-1 and N-1-1) was performed for the 2016 and 2022 Base Case load forecasts using a linear powerflow solution. The results show that the shutdown of the Indian Point Plant exacerbates the loading across the UPNY-SENY interface, with Leeds – Pleasant Valley and Athens – Pleasant Valley 345 kV lines loaded to 124% of their LTE rating in 2016 and 158% in 2022 following N-1-1 transmission contingencies. Along the parallel Marcy South corridor, the Fraser – Coopers Corners and Rock Tavern – Ramapo 345 kV lines are each loaded to over 110% of their LTE ratings in 2022 following N-1-1 transmission contingencies. Additionally, the Roseton – East Fishkill 345 kV line, which can impact UPNY-SENY, is loaded to 107% of its normal rating in 2022 due to lack of available system adjustments necessary to reduce flow following a single contingency. Compensatory megawatts would be necessary in Zones G, H, I, J, or the western portion of K to mitigate these overloads. For example, compensatory megawatts amounting to 1000 MW in 2016 and 2425 MW in 2022 located at Dunwoodie/Sprain Brook or points south would alleviate these overloads.[7]

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[7] The amount of compensatory megawatts in Zones G, H, or I necessary to alleviate the transmission security overloads may increase depending on the specific location of the compensatory resource.

Transfer limit analysis was performed with both Indian Point units out-of–service (i.e. beginning 2016), and it was assumed all other generation capacity in Zones G through I would be fully dispatched, supporting Southeastern New York load. The analysis shows that, under typical load conditions, the ability to transfer power to Zone J and Zone K would be limited by the upstream UPNY-SENY interface. If the Indian Point Plant were to be retired and new generation interconnected below the UPNY-SENY interface without proper system reinforcement, the UPNY-ConEd and I to J and K interface may be constrained by voltage or thermal limits.

Furthermore, as reported in the 2010 RNA, under stress conditions the voltage performance on the system without the Indian Point Plant would be degraded. In all cases, power flows replacing the Indian Point generation cause increased reactive power losses in addition to the loss of the reactive output from the plant. It would be necessary to take emergency operations measures, including load relief[8] to eliminate the transmission security violations in Southeastern New York.

For the Base Case load forecast, LOLE was 0.48 in 2016, a significant violation of the 0.1 days per year criterion. Beyond 2016, due to annual load growth the LOLE continues to escalate for the remainder of the Study Period reaching an LOLE of 3.63 days per year in 2022. As shown in Table 4-13, the low load forecast causes the LOLE violation to be deferred to 2018, while the high (econometric) load forecast results in significantly higher LOLE violations in 2016 and 2022.

Table 4-13: Indian Point Plant Retirement LOLE Results

Sensitivity	***Year 2016 LOLE***	***Year 2022 LOLE***
Base Case load forecast	0.48	3.63
Low (15 x 15) load forecast	0.07	0.80
High (Econometric) load forecast	1.50	9.37

[8] According to the NYISO Emergency Operations Manual, Load Relief Capability is described as including measures such as: voltage reduction, load shedding, and other curtailment measures such as interruptible customers and public appeals.

Written Statement of Thomas Rumsey
Vice President – External Affairs
New York Independent System Operator

Senate Energy and Telecommunications Committee
Senator George D. Maziarz, Chairman

Public Hearing

"Indian Point Power Plant"

September 30, 2013

I. New York Independent System Operator – Organization Summary

The NYISO is an independent not-for-profit corporation that carries out three key functions relating to the electric system serving New York State. We are responsible for the reliable operation of New York's bulk electric system in accordance with all national, regional and state reliability requirements. Additionally, we administer competitive wholesale electricity markets to satisfy electrical demand, providing benefits to consumers. Lastly, we plan for the reliability and power demands of the future and participate as a non-voting member of the New York State Energy Planning Board.

The NYISO is governed by an independent Board of Directors and a shared governance structure comprised of representatives from every industry sector, including generators, transmission owners, municipalities, end users, and environmental and consumer interests. The New York State Department of Public Service actively participates in the NYISO's shared governance process.

II. Summary

As the independent operator of the electric system, the NYISO has a legal obligation to provide open, non-discriminatory access to the electric system. We do not advocate for – or against – any particular power resource and we maintain a balanced, unbiased perspective on generation, transmission and demand-side resources. Consequently, we are not testifying today about whether a shutdown of Indian Point Energy Center should or should not occur. Nor are we commenting in this testimony on the proposals being reviewed by the New York Public Service Commission (PSC) in Case 12-E-0503, Proceeding on Motion of the Commission to Review

Generation Retirement Contingency Plans. Rather, we are here today to discuss the potential impacts to the reliability of the bulk electric power system in New York if Indian Point were to close.

There are three key elements to consider on the topic of the potential closure of Indian Point.

First, to meet reliability requirements, replacement resources have to be in place prior to a closure of Indian Point. Failure to do so would have serious reliability consequences, including the possibility of rolling consumer blackouts.

Second, due to New York's existing transmission limitations, new generation, additional demand response, and transmission upgrades would likely be the potential solutions in response to an Indian Point closure in the next three years.

Third, New York's energy infrastructure is aging and many facilities will require replacement over the next 20 years. Whether Indian Point remains in service or not, it would be prudent to pursue upgrades to the existing transmission system to make better use of statewide generating resources, including renewables from wind power projects already developed and for those additionally proposed throughout upstate New York.

III. Reliability Impact

Closure of the Indian Point Energy Center, without replacement resources in service beforehand, would jeopardize the reliability of the New York bulk electric grid. The North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the New York State Reliability Council are the agencies that establish and enforce New York's reliability requirements. These three agencies provide compliance oversight and enforcement by routinely performing audits on the NYISO and the New York electric utilities. The PSC has also adopted the NPCC and New York State Reliability Council rules as state regulations.

To ensure it continues to meet these reliability requirements, the NYISO has developed a robust planning process. Every two years the NYISO performs a Reliability Needs Assessment (RNA) to examine whether the bulk electric power system in New York will have sufficient resources to maintain reliable electric service over a ten-year planning horizon. If a reliability need is identified, the NYISO reports those findings and solicits market-based solutions to meet the identified need. Concurrently, the NYISO requires the affected New York State Transmission Owners (TOs) to submit a “regulated backstop solution” that could be implemented in case adequate market-based solutions do not materialize. Other developers are free to submit alternative regulated solutions that could be built and funded through transmission rates if they are more efficient or cost effective than the utility regulated backstop solution. Transmission projects that meet an identified need and NYISO tariff requirements may be able to recover their costs in rates administered through the NYISO’s tariffs, while generation and demand-reducing projects can seek recovery under state law. The NYISO selects transmission projects needed to meet reliability needs, and the Public Service Commission chooses what generation, demand reduction and energy efficiency projects should proceed to keep adequate resources available to meet expected energy needs.

The NYISO’s 2012 RNA assumed the Indian Point Energy Center would be available, as no decision had been made to close the plant by federal or state regulators or by the plant’s owners. The RNA found that, with the continued operation of Indian Point, New York would begin to need new resources in 2020. The need was caused by generation retirements, increases in forecasted load, and a decrease in demand response resources participating in the NYISO’s market programs. After issuing the 2012 RNA, the NYISO solicited market-based projects and regulated backstop solutions to meet the needs identified if the market solutions do not materialize by the need date.

In its 2012 Comprehensive Reliability Plan (CRP), the NYISO determined the year of need for new resources advanced to 2019 due to a net decrease in generating resources on the system. Although Gowanus Units 1 and 4 with 270 MW decided not to retire as planned, the 500 MW Danskammer power plant closed. Nevertheless, the NYISO determined that viable market-based solutions had been offered to meet the year of need in 2019 without the NYISO having to call on a regulated solution to be built at ratepayer expense. The NYISO will continue to monitor the market-based projects to ensure they will be in service by 2019, and will call upon a regulated solution to proceed if needed. It is important to note that between 2009 and 2013 the Lower Hudson Valley and New York City regions have experienced a net reduction of 1,258 MW in electric generating capacity. Moreover, since the summer of 2009, the amount of demand response resources, which can meet electricity demand by reducing consumption instead of having to build new power plants, has declined by 362.2 MW in the Lower Hudson Valley and New York City.

The NYISO analyzed the impact of the unavailability of the Indian Point Energy Center in its 2012 RNA as a possible scenario. Consistent with past findings, the NYISO determined if Indian Point is not available in the fall of 2015, there would be a need for new resources on the bulk power system by summer 2016.

The NYISO noted in its CRP that the PSC had commenced a proceeding to formulate a reliability contingency plan to address the possible closure of the nuclear generating facilities at Indian Point. As the independent system operator, the NYISO takes no position in the PSC's proceeding on whether the PSC should adopt a reliability contingency plan for the closure of Indian Point or not. Nor does the NYISO take a position on whether the PSC should proceed with specific transmission, generation or energy efficiency projects or programs, now or in the future. Rather, the NYISO's role is to provide technical information and system modeling to the Department of Public Service Staff (DPS Staff) on various contingency situations that could lead to reliability needs, and on combinations of transmission, generation and demand-reducing resources that could satisfy those needs.

Since last year, the NYISO updated its analysis of the reliability needs that would arise on the bulk power system if Indian Point was no longer available. The NYISO previously testified on this subject before the New York State Assembly in January 2012 and stated that absent Indian Point, or adequate replacement resources, there would be a deficiency of over 1,200 MW by the summer of 2016, and that this deficiency would increase over time. Our analysis finds that the amount of resources required remains roughly the same. Over 1,100 MW of new resources would be needed if Indian Point were not in service in the summer of 2016, assuming normal weather and operational conditions, to maintain the bulk power system within reliability standard limits. The NYISO is required to plan for bulk power system reliability over a 10 year horizon. Under normal summer conditions, the resource deficiency in Southeastern New York without Indian Point after 2016 would increase by approximately 175 MW per year, with a total deficiency in 2023 of over 2,250 MW, assuming all existing generation is in service.

A number of changes have occurred since our January 2012 testimony that contribute to the updated 1,100 MW need figure for summer 2016. Increasing the level of need are; (i) growth in the load forecast for summer 2016 due to updated economic conditions, and (ii) reduced generation in the Lower Hudson Valley and New York City due to retirements, including the closure of the Danskammer facility, and other system changes. Counterbalancing these factors are changes that decrease the level of need, which include an increase in the import capability into Southeastern New York caused by changes in the system dispatch and facility ratings. Also, the Hudson Transmission Project between New Jersey and Manhattan could provide 320 MW to the New York grid. Although the scale of the bulk power system reliability need has not changed significantly since the NYISO's January 2012 testimony, the point remains that adequate replacement resources are required prior to a closure of Indian Point. Otherwise, New York will not be able comply with reliability standards. New York has more than an adequate level of generation capacity for 2013. However, the capability of the existing electric transmission system is not sufficient to allow upstate supply to fully meet demand in the Southeast portion of the State.

IV. Possible Solutions if Indian Point Becomes Unavailable

The reliability assessments performed by the NYISO raise the question of what replacement solutions could be available in the short term. Regarding transmission, there are five alternating current (AC) transmission projects in the NYISO's interconnection queue that would increase the transmission capacity of New York's 345 kV system. Studies will be required to determine the amount by which these projects will increase the transfer capability of the NYISO's system. Some of these projects have been offered by the New York Transmission Owners, and some by other developers, in the PSC's Energy Highway proceedings examining transmission upgrades. At the request of the DPS, the NYISO serves as a technical advisor in that proceeding, providing data and system modeling capability to determine the impacts of various combinations of projects on transmission system capability.

Additionally, two merchant high voltage direct current (DC) projects have entered the NYISO's interconnection queue proposals to build in New York State: the TDI Champlain Hudson Power Express Project, and the West Point Partners project. Each project seeks to inject 1,000 MW of additional power directly into the New York City area**.** It is uncertain at this time when, or if, these transmission projects will be built. In its proceeding addressing one of the Governor's Energy Highway initiatives, the PSC is also considering alternating current (AC) transmission upgrades that would add 1,000 MW of transfer capability between upstate and downstate New York. Those upgrades would not address the potential unavailability of Indian Point in 2016, however, because they are not scheduled to be in service until 2018.

Additionally, there are a number of generation projects proposed in Southeast New York that may come into service by 2016. Excluding repowering projects, there are over 3,300 MW of proposed generation facilities in the Lower Hudson Valley and New York City currently in the NYISO's interconnection queue. Of these, approximately 1,900 MW have identified a commercial operation date in time for summer 2016. Currently, U.S. Power Generating has two steam units at its Astoria facility that are mothballed, totaling 552 MW of net capacity. The NYISO cannot predict the likelihood of these units returning to service. NRG Energy has made a variety of repowering proposals to the PSC for units it owns in Astoria, New York that would increase their net generating capacity by 405 MW.

Another short term solution to the need for new resources could be additional demand response, which can reduce the level of demand on the bulk power system when called upon to perform. Such demand response resources, whether consisting of reduced consumption or behind-the-meter generation, could lower the deficiency that would be caused if Indian Point became unavailable. The level of that impact would depend on the amount, location and availability of demand response as a capacity resource equivalent to generation.

For all of these transmission and generation resources, their contribution to meeting system reliability needs in the absence of Indian Point will depend on the extent to which these facilities can fully deliver energy to customers, and on the extent to which they may negatively impact transfer capability into southeastern New York. Moreover, the voltage performance of the system must be considered when evaluating potential replacement resources. The impacts of specific facilities must be studied by the NYISO and the interconnecting transmission owner.

V. Market Impact

With respect to market impacts, electricity generated by the Indian Point Energy Center represents approximately 30% of the power consumed by New York City. Because we do not know the portfolio of generators and other resources that would replace the energy and capacity of Indian Point if it is no longer in service, it is not possible to accurately estimate what the actual cost impacts might be.

If the State of New York decides to permit and fund transmission or generation resources as part of a contingency plan for Indian Point, those actions should be undertaken in a manner that is consistent with New York's competitive markets.

VI. Transmission Reinforcement

Today's discussion about the impact of Indian Point provides an opportunity to discuss the benefits of improving New York's electric system. Considering the timeframe and the units that have been proposed to date, a short-term solution to an Indian Point shutdown would likely consist of new natural gas-fired generation in, or near, the New York City metropolitan area. Another possibility might consist of transmission upgrades that could be made in the short-term. Generally, new generation resources can be added more quickly than major transmission upgrades. As discussed above, increasing the potential for demand response during peak load times could also be part of the solution. However, we should use this opportunity to also look at long-term solutions, with consideration given to replacing aging transmission infrastructure with upgraded, expanded facilities along existing rights-of-way. Separately from the Indian Point contingency plan proceeding, the PSC's AC transmission upgrade proceeding is examining potential upgrades to New York's AC bulk power transmission network.

Upgrades to the existing transmission system could provide reliability benefits by allowing upstate resources to meet the needs of the New York City metropolitan area. These same transmission upgrades could provide consumer benefits by relieving some of the historic congestion bottlenecks that continue to impact the economic operation of New York's electric system. By improving the capability of the Central to East and Leeds to Pleasant Valley transmission corridors, New York could increase the ability to move excess generation from upstate to downstate load centers. Given that the upstate and western areas of New York State have the greatest potential for the development of renewable resources such as wind generation, transmission upgrades could help transport renewable energy from these areas to load centers in southeastern areas of New York State. Such transmission upgrades would also add significant reliability benefits by allowing for a more diverse set of generating resources to meet New York's electric needs. New York's electric transmission infrastructure is aging and will require significant investment. Eighty four (84) percent of New York's high-voltage transmission lines were built prior to 1980. Of the state's more than 11,000 circuit miles of transmission lines, nearly 4,700 circuit miles will require replacement within the next 30 years. The New York Transmission Owners and other developers are proposing transmission upgrades in the NYISO's planning processes and in the state Energy Highway proceedings that would increase upstate to downstate transfer capability, help address future electricity needs, and support fuel diversity and the growth of renewable energy resources.

VII. Closing

The NYISO is thankful for the opportunity to participate in the New York Senate Energy & Telecommunications Committee's hearing on the Indian Point Power Plant. There is one point on which everyone can agree: New York State is at a crossroads regarding its electric infrastructure. To summarize the three points of this testimony:

One: To meet reliability requirements, 1,100 MW of replacement resources have to be in place prior to a closure of the Indian Point Energy Center.

Two: Due to New York's existing transmission limitations, new generation, additional demand response, and limited transmission upgrades would be the likely potential solutions in response to an Indian Point closure by the summer of 2016.

Three: Due to New York's aging energy infrastructure, we have an opportunity to pursue beneficial upgrades to New York's transmission system - with or without the closing of Indian Point.

Growing Wind

Final Report of the NYISO 2010 Wind Generation Study



September 2010

Executive Summary

1. Introduction

In 2004, the New York State Public Service Commission (PSC) adopted a Renewable Portfolio Standard (RPS) that requires 25% of New York States' electricity needs to be supplied by renewable resources by 2013. The development of the RPS prompted the New York Independent System Operator (NYISO) and the New York State Energy Research and Development Authority (NYSERDA) to co-fund a study which was designed to conduct a comprehensive assessment of wind technology, and to perform a detailed technical study to evaluate the impact of large-scale integration of wind generation on the New York Power System (NYPS). The study was conducted by GE Power System Energy Consulting in fall of 2003 and completed by the end of 2004 (i.e., "the 2004 Study").

The overall conclusion of the 2004 Study was the expectation that the NYPS can reliably accommodate up to a 10% penetration of wind generation or 3,300 megawatts (MW) with only minor adjustments to and extensions of its existing planning, operation, and reliability practices. Since the completion of the 2004 Study, a number of the recommendations contained in the report have been adopted. They include the adoption of a low voltage ride through standard, a voltage performance standard and the implementation of a centralized forecasting service for wind plants.

The nameplate capacity of installed wind generation has now increased to 1,275 MW and the NYISO interconnection queue significantly exceeds the 3,300 MW that was originally studied. In addition, the PSC has increased New York State's RPS standard to 30% by 2015. As a result, the NYISO has been studying the integration of installed wind plants with nameplate ratings that total from 3,500 MW to 8,000 MW.

From an operational perspective, power systems are dynamic, and are affected by factors that change each second, minute, hour, day, season, and year. In each and every time frame of operation, it is essential that balance be maintained between the load on the system and the available supply of generation. In the very short time frames (seconds-to-minutes), bulk power system reliability is almost entirely maintained by automatic equipment and control systems, such as automatic generation control (AGC). In the intermediate to longer time frames, system operators and operational planners are the primary keys to maintaining system reliability. The key metric driving operational decisions in all time frames are the amount of expected load and its variability. The magnitude of these challenges increases with the significant addition of wind-generating resources.

Variable generation, such as wind and solar, have high fixed costs and very low marginal operating costs which tend to reduce overall production costs and marginal energy prices. However, as will be shown in this study, variable resources require additional resources to be available to respond to the increased system variability, which offsets some of the production cost savings. The primary focus of this report is on the technical impacts of increasing the penetration of wind resources. The impact on production costs, locational-based marginal prices, congestion costs and uplift are presented based on the production costs simulations that were conducted. The study did not conduct, nor did the study scope contemplate, a full economic evaluation of the costs and benefits of wind generation.

2. Technical Approach

Due to its variable nature and the uncertainty of its output, the pattern of wind generation has more in common with load than it does with conventional generation. Therefore, the primary metric of interest in assessing the impact of wind on system operations is "net load," which is defined as the load minus wind. It is net load to which dispatchable resources consisting of primarily fossil fired generation must be able to respond. The study evaluated the impact of up to 8,000 MW of wind-generation resources on system variability. The study process consisted of the following tasks:

Task 1: Develop wind generator penetration scenarios for selected study years including MW output profile and MW load profile.

Task 2: Develop and implement performance-monitoring processes for operating wind generators.

Task 3: Update the review of the European experience conducted for the 2004 study with currently existing wind plants, and review the experiences and studies for wind plants in other regions of the US and Canada.

Task 4: Study the potential impact on system operations of wind generators at various future levels of installed MW for the selected study years as it relates to regulation requirements and the overall impact on ramping.

Task 5: Evaluate the impact of the higher penetration of wind generation from a system planning perspective – including the evaluation of transmission limitations – by identifying specific transmission constraints (limiting element/contingency) for each wind project (or group of projects)

Task 6: Evaluate the impact of the higher penetration of wind generation on the overall system energy production by fuel types, locational-based marginal prices (LBMP), congestion cost, operating reserves, regulation requirements, and load following requirements.

Task 7: Identify the impact of transmission constraints on wind energy that is not deliverable (i.e., "bottled") and identify possible upgrades for the limiting elements/transmission facilities.

The technical analysis required by the study task includes a set of sequential steps that are needed to successfully conduct a comprehensive analysis of integrating wind into the grid as a function of penetration level. In addition to the traditional planning analysis and economic assessments, the integration of a variable generation resources requires the assessment of operational issues as well. Operational analyses in conjunction with traditional planning assessments are necessary to fully understand the overall technical implication and potential cost associated with integrating variable generation resources. This process includes the following steps:

Step 1: A determination of the interconnection point of the resources and potential output

Step 2: A thorough assessment of the transmission system to determine the contingencies and constraints that could adversely impact wind

Step 3: A statistical analysis of the interaction of load and wind as measured by the net load to determine the impact of variable wind resources on overall system variability and operational requirements

Step 4: Dispatch simulation with a production cost tool to determine the amount of wind that will be constrained and the impact of wind on the overall dispatchablility such as plant commitment and economics of the system

Step 5: An identification and rank ordering of the transmission constraints that impact the dispatchablility of wind

Step 6: Development of transmission upgrades to relieve wind constraints for the various penetration levels of wind

Step 7: Redo Step 4 with upgrades and needed operational adjustments determined in Step 3 to determine the full impact

Step 8: Conduct a dynamic assessment to determine if the planned system with the higher levels of wind will satisfy stability criteria

Step 9: Conduct loss-of-load-expectation (LOLE) analysis to determine the impact of installed wind on system load carrying capability or reserve margin requirements.

The study spanned a period of time from the spring of 2008 to the spring of 2010 and involved an extensive review of not only the New York Control Area (NYCA) bulk power system, but the underlying 115 kV transmission system as well. It also involved significant feed-forward and feedback between the power flow analysis and the simulation of NYISO security constrained economic dispatch. This process was used to determine the impact of transmission constraints on the energy deliverability of the wind plants as well as how relieving the transmission constraints affected the energy deliverability of the wind plants. Given the study scope and the plant-by-plant analysis, this study is one of the most comprehensive assessments undertaken for evaluating wind integration for a large balancing area.

3. Study Findings

The study has determined that as the level of installed wind plant generation increases, system variability, as measured by the net-load, increases for the system as whole. The increase exceeds 20% on an average annual basis for the 8 GW wind scenario and the 2018 loads. The level of increase varies by season, month, and time-of-day. This will result in higher magnitude ramping events in all timeframes. Ramp is the measure of the change in net load over time to which the dispatchable resources need to respond. Study results are reported for the New York system as a whole and for three superzones (Western load zones A-E, Hudson Valley load zones F-I, and the New York City and Long island load zones J-K). The study resulted in the following findings with respect to system reliability, system operations and dispatch, and transmission planning.

3.1 Reliability Finding:

This study has determined that that the addition of up to 8 GW of wind generation to the New York power system will have no adverse reliability impact. The 8 GW of wind would supply in excess of 10% of the system's energy requirement. On a nameplate basis, 8 GW of wind exceeds 20% of the expected 2018 peak load. This finding is predicated on the analysis presented in this report and the following NYISO actions and expectations:

The NYISO has established a centralized wind forecasting system for scheduling of wind resources and requires wind plants to provide meteorological data to the NYISO for use in forecasting their output. *This item was approved by the Federal Energy Regulatory Commission (FERC) and implemented by the NYISO in 2008.*

The NYISO is the first grid operator to fully integrate wind resources with economic dispatch of electricity through implementation of its wind energy management initiative. If needed to maintain system security, the NYISO system operators can dispatch wind plants down to a lower output. *This item was approved by the Federal Energy Regulatory Commission (FERC) and implemented by the NYISO in 2009.*

The NYISO's wind plant interconnection process requires wind plants: 1) To participate fully in the NYISO's supervisory control and data acquisition processes; 2) To meet a low voltage ride through standard; and 3) conduct voltage testing to evaluate whether the interconnection of wind plants will have an adverse impact on the system voltage profile at the point of interconnection. In addition, the NYISO will continue to integrate best practice requirements into its interconnection processes.

The NYISO's development of new market rules assist in expanding the use of new energy storage systems that complement wind generation. *This item was approved by the Federal Energy Regulatory Commission (FERC) and implemented by the NYISO in 2009.*

The NYISO's installed resource base will have sufficient resources to support wind plant operations. As described in this report, the overall availability of wind resources is much less than other resources and their variability (changing output as wind speed changes) increases the magnitude of the ramps. For a system that meets its resource adequacy criteria (e.g., the 1 day in ten years), the additions of 1 MW of resources generally means that 1 MW of existing resources could be removed and still meet the resource adequacy criteria. However, the addition of 1 MW of wind would allow approximately 0.2

MW to 0.3 MW of existing resources to be removed in order to still meet the resource adequacy criteria. The balance of the conventional generation must remain in service to be available for those times when the wind plants are unavailable because of wind conditions and to support larger magnitude ramp events.

3.2 Operation and Dispatch Simulation Findings:

Analysis of the wind plant output and dispatch simulations resulted in the following findings for the expected impact of wind plant output on system operations and dispatch:

Finding One - Analysis of five minute load data coupled with a ten minute persistence for forecasting wind plant output (i.e., wind plant output was projected to maintain its current level for the next five minute economic dispatch cycle) concluded that increased system variability will result in a need for increased regulation resources. The need for regulation resources varies by time of day, day of the week and seasons of the year. The analysis determined that the average regulation requirement increases approximately 9% for every 1,000 MW increase between the 4,250 MW and 8,000 MW wind penetration level. The analysis for 8 GW of wind and 2018 loads (37,130 MW peak) resulted in the overall weighted average regulation requirement increasing by 116 MW. The maximum increase is 225 MW (a change from a 175 MW requirement up to 400 MW) for the June-August season hour beginning (HB) 1400. The highest requirement is 425 MW in the June-August season HB2000/HB2100.

Finding Two - The amount of dispatchable fossil generation committed to meet load decreases as the level of installed nameplate wind increases. However, a greater percentage of the dispatchable generation is committed to respond to changes in the net-load (load minus wind) than committed to meet the overall energy needs of the system. The magnitudes of ramp or load following events are reduced when wind is in phase with the load (i.e., moving in the same direction). However, for many hours such as the morning ramp or the evening load drop, wind is out of phase with the load (i.e., moving in the opposite direction). These results in ramp or net-load following events that are of higher magnitude than those that would result from changes in load alone. It is these ramp or load following events to which the dispatchable resources must respond.

Finding Three - Simulations with 8 GW of installed wind resulted in hourly net-load up and down ramps that exceeded by approximately 20% the ramps that resulted from load alone. It was also determined from the simulations the NYISO security constrained economic dispatch processes are sufficient to reliably respond to the increase in the magnitude of the net-load ramps. This finding is based on the expectation that sufficient resources will be available to support the variability of the wind generation. For example, the data base used for these simulations had installed reserve margins which exceeded 30%.

Finding Four - Simulations for 8 GW of wind generation concluded that no change in the amount of operating reserves[1] was needed to cover the largest instantaneous loss of source or contingency event. The system is designed to sustain the loss of 1,200 MW instantaneously with replacement within ten minutes where as a large loss of wind generation occurs over several minutes to hours. The

[1] Operating reserves is the amount of resources that are needed to be available for real-time operations to cover the instantaneous and unexpected loss of resources. The New York power system is operated to protect the system against the sudden loss of 1,200 MW of resources. Operating reserve as stated is an operational concept while the reserve margin discussed in section 3.3 is a planning concept. The required reserve margin is designed to maintain, at an acceptable level, the risk of not having sufficient resources to avoid an involuntary loss-of-load event.

analysis of the simulated data found for 8 GW of installed wind a maximum drop in wind output of 629 MW occurred in ten minutes, 962 MW in thirty minutes and 1,395 MW in an hour, respectively.

3.3 Resource Adequacy Findings:

To evaluate the impact of wind resources on NYISO installed reserve requirements, the study started with the New York State Reliability Council (NYSRC) Installed Reserve Margin[2] Study for the 2010-2011 Capability Year.[3] The NYSRC base case had an installed reserve margin of 17.9% to meet loss-of-load-expectation (LOLE) criteria of 0.1 days per year. That base case was updated to bring the installed wind resources to the full 8 GW of wind studied. The analysis of a system with this level of installed wind resulted in the following findings.

Finding One – All other things being equal, the addition of 8 GW of wind resources to the NYSRC base case reduced the LOLE from the 0.1 days per year to approximately 0.02 days per year.

Finding Two – To meet the required reliability criteria, the NYISO reserve margin would have to increase from its current level of 18% to almost 30% with 8 GW of nameplate wind as part of the resource mix. This was determined by using the methodology of removing capacity to bring the system to criteria and adding transfer capability in order for the wind plants to qualify for Capacity Rights Interconnection Service (CRIS). However, it should be noted that the NYISO's capacity market requires load serving entities to procure unforced capacity (UCAP) and capacity is derated to its UCAP value for purchase. As a result the total amount UCAP that needs to be purchased to meet reliability criteria remains essentially unchanged. The increase in reserve margin is because on capacity basis 1 MW of wind is equivalent to approximately 0.2 MW to 0.3 MW of conventional generation. Therefore, it requires a lot more installed wind to provide the same level of UCAP as a conventional generator. This results in an increase in the installed reserve margin which is computed on an installed nameplate basis.

Finding Three – The LOLE analysis resulted in an effective load carrying capability (ELCC) for the wind plants studied that exceeded 20%. The ELCC for this study exceeded the ELCC finding in the 2004 study by a factor of 2. Off-shore wind exhibits ELCC that is higher than on-shore wind because a greater percentage of the off-shore wind plants energy production occurs during peak hours. As an example, the GridView wind plant simulations based on 2006 wind data resulted in a 37.4% overall annual capacity factor (CF) for off-shore wind VS 34.3% for on-shore wind. However, the CF for off-shore wind plants during peak hours (the hours between 7am and 11 pm weekdays) was 39.7% for off-shore wind VS 32.5% for on-shore wind.

3.4 Production Cost Simulation Findings:

The production cost simulations conducted with ABB's GridView economic dispatch simulation model and the base case transmission system resulted in the following findings:

[2] Reserve margin is the amount of additional capacity above the peak load that is needed so that the risk of not having sufficient capacity available to meet the load meets the minimum reliability criteria. It is expressed as a percentage and is calculated by dividing the required level of resources by the expected peak load. Resources can be unavailable because of equipment failure, maintenance outage, lack of fuel, etc. The higher the unavailability of the overall resource mix, the higher the installed reserve margin will be.

[3] http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp

Finding One - As the amount of wind generation increases, the overall system production costs decrease. For the 2013 study year, the production costs drop from the base case total of almost $6 billion to a level of approximately $5.3 billion for the 6,000 MW wind scenario. This represents a drop of 11.1% in production costs. For the 2018 study year, the production costs drop from the base case total of almost $7.8 billion to a level of approximately $6.5 billion for the 8,000 MW wind scenario. This represents a drop of 16.6% in production costs. The change in production costs reflect the commitment of resources that are needed to support the higher magnitude ramping events but do not reflect the costs of the additional regulating resources.

Finding Two - Based on the economic assumptions used in the CARIS study, locational-based marginal prices (LBMP) or spot prices decline as significant amounts of essentially zero production cost generation that participates as price taker is added to the resource mix. For the 2018 simulations, the NYISO system average LBMP prices are 9.1% lower for the 8 GW wind scenario when compared to the base case or 1,275 MW of installed wind.

Finding Three - The LBMP price impacts are greatest in the superzones where the wind generation is located and tends to increase the price spread between upstate where wind is primarily located in the study and downstate, which implies an increase in transmission congestion.

Finding Four - The primary fuel displaced by increasing penetration of wind generation is natural gas. For the simulations with 8 GW of wind with 2018 loads, the total amount of fossil-fired generation displaced was approximately 15,500 GWh. Gas-fired generation accounted for approximately 13,000 GWh or approximately 84% of the total. Oil and coal accounted for approximately 2,050 GWh and 465.1 GWh respectively, or approximately 13% and 3% of the total fossil generation displaced.

Finding Five - As suggested by the LBMP trends, the congestion payments in superzones F-I and J-K increase as the level of installed wind generation is increased. The overall increase in congestion payments on a percentage basis as measured against the base case compared to 6,000 MW of wind in 2013 and 8,000 MW in 2018 ranges from a high of 85% for superzone F-I in 2013 to a low of 64% for superzone J-K in 2018.

Finding Six - The addition of wind resources to superzone J-K in the 2018 case puts downward pressure on LBMPs in those zones, and therefore lowers congestion payments.

Finding Seven - Uplift costs tend to increase in superzones A-E and F-I as the level of installed wind generation increases. Superzone J-K uplift cost are for the most part flat as the level of installed wind increases for 2013 but actually decreases for 2018. This is the result of the offshore wind which has a capacity factor of almost 39% and tends to be more coincident with the daily load cycle and displaces high cost on peak generation in the superzone while requiring less capacity for higher magnitude ramping events. Off shore wind also provides greater capacity benefits.

Finding Eight - The capacity factors for the thermal plants are, as expected, decreased by the addition of wind plants, but this is partially offset by increasing load. The biggest reduction in annual capacity factors from the 2013 base case level of 1,275 MW of wind when compared to the 8 GW scenarios occurs for the combined cycle plants in all superzones with a 30% decline in superzone A-E, 11% decline in superzone F-I and 6% decline superzone J-K. As would be expected the biggest impact is in the superzone with the highest level of installed wind with transmission capacity limitations between the superzones contributing to the reduction.

3.5 Environmental Findings:

For the 2018 load levels, the dispatch simulations with 8 GW of wind resources resulted in the following emissions reductions in comparison to the base case with 1,275 MW of installed wind:

Finding One – A CO_2 emission reduction of approximately 4.9 million short tons or a reduction of 8.5%.

Finding Two - Each GWh of displaced fossil-fired generation which primarily consisted of natural gas resulted in an average reduction in CO_2 of approximately 315 tons.

Finding Three - A NOx emission reduction of approximately 2,730 short tons or a reduction of 7%.

Finding Four – A SO_2 emissions reduction of 6,475 short tons or a reduction of 9.7%.

3.6 Transmission Planning Findings:

Extensive power flow analysis in conjunction with dispatch simulations was conducted to determine the impact of transmission system limitations on the energy deliverability of the wind plant output. The analysis resulted in the following findings:

Finding One - Given the existing transmission system capability, the 6 GW scenario determined that 8.8% of the energy production of the wind plants in three areas in upstate New York would be "bottled" or not deliverable.

Finding Two – The primary location of the transmission constraints was in the local transmission facilities or 115 kV voltage level.

Finding Three - The off-shore wind energy as modeled was fully deliverable and feeds directly into the superzone J-K load pockets.

Finding Four - The study evaluated 500 miles of transmission lines and 40 substations to determine potential upgrades that would result in the "unbottling" of the wind energy.

Finding Five - If all the upgrades studied were implemented, the amount of wind energy not deliverable would be reduced to less than 2% of the upstate wind.

Finding Six - Depending on the scope of upgrades required, such as reconductoring of transmission lines compared to rebuilding or upgrading terminal equipment, the cost of the upgrades could range from $75 million to $325 million. However, it should be noted that many of the transmission facilities studied are approaching the end of their expected useful lives.

Finding Seven - Transient Stability Analysis was conducted to evaluate the impact of high wind penetration on NYCA system stability performance. The primary interface tested was the Central East. The Central East stability performance has been shown historically to be key factor in the dynamic performance of the NYISO power grid. The NYISO power grid (and the Interconnection) system demonstrated a stable and well damped response (angles and voltages) for all the contingencies tested on high wind generation on-peak and off-peak cases. There is no indication of units tripping due to over/under voltage or over/under frequency.

Finding Eight - Wind plants that are in the NYISO interconnection 2008 class year study and beyond may require system deliverability upgrades to qualify for Capacity Resource Integration Service (CRIS). This totals approximately 4,600 MW of new nameplate wind plants that were included in the study. In order to qualify for capacity payments, the wind plants in class year 2009/2010 and beyond in upstate New York would need to increase transmission transfer capability between upstate New York and southeast New York (a.k.a., the UPNY-SENY interface). This transmission interface primarily consists of 345 kV transmission lines in the Mid-Hudson valley region running through Greene County, New York south of Albany to Dutchess County, New York or between Zones E and F and Zone G. The study determined that approximately 460 MW of interface transfer capability needs to be added to this interface for the wind plants that did not qualify for capacity payments to be eligible for them. This does not impact the deliverability of the wind plants' energy but only their ability to qualify for capacity payments or CRIS.

4. Conclusions:

The primary finding of the study is that wind generation can supply reliable clean energy at a very low cost of production to the New York power grid. This energy results in significant savings in overall system production costs, reductions in “greenhouse” gases such as CO_2 and other emissions such as NOx and SO_2 as well an overall reduction in wholesale electricity prices. However, wind plants require a significant upfront capital investment. In addition, wind plants, because of their variable nature and the uncertainty of their output, provide a greater challenge to power system operation than conventional power plants. This study determined that the NYISO’s systems and procedures (which include the security constrained economic dispatch and the practices that have been adopted to accommodate wind resources) will allow for the integration of up to 8 GW of installed wind plants without any adverse reliability impacts.

This conclusion is predicated on the assumption that a sufficient resource base is maintained to support the wind. The study determined that 8 GW of wind would reduce the need for conventional or dispatchable fossil fired generation on the order of 1.6 to 2 GW or an amount equivalent to 20-25% of the installed nameplate wind. This is the result of the much lower overall availability of wind-produced Energy, when compared to conventional generation. This means an amount of fossil generation equivalent to 75-80% of the nameplate installed wind needs to be available for those times when the wind isn’t blowing or the wind plant output is at very low levels. Non-wind generation is needed to respond to the higher magnitude ramps that will result because of winds variable nature.

As wind resources are added to the resource mix, their lower availability could result in an increase in the installed reserve margin and a decline in spot market prices. The impact of these changing conditions has not been analyzed in this report.

The fluctuating nature and the uncertainty associated with predicting wind plant output levels manifests itself as an increase in overall system variability as measured by the net load (load minus wind). In response to these increased operational challenges the NYISO has implemented changes to its operational practices such as being the first ISO to incorporate variable generation resources into security constrained economic dispatch (SCED) and to implement a centralized forecasting process for wind resources. The study concluded that at higher levels of installed wind generation the system will experience higher magnitude ramping events and will require additional regulation resources to respond to increased variability during the five minute dispatch cycle. The analysis determined that the average regulation requirement will need to increase by approximately 9% for every 1,000 MW increase in wind generation between the 4,250 MW and 8,000 MW.

Although the addition of wind 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. These transmission constraints prevent lower cost generation in upstate New York from displacing higher costs generation in southeast New York. This report did not analyze the potential financial impact of an increase in transfer capability from upstate into southeast New York.

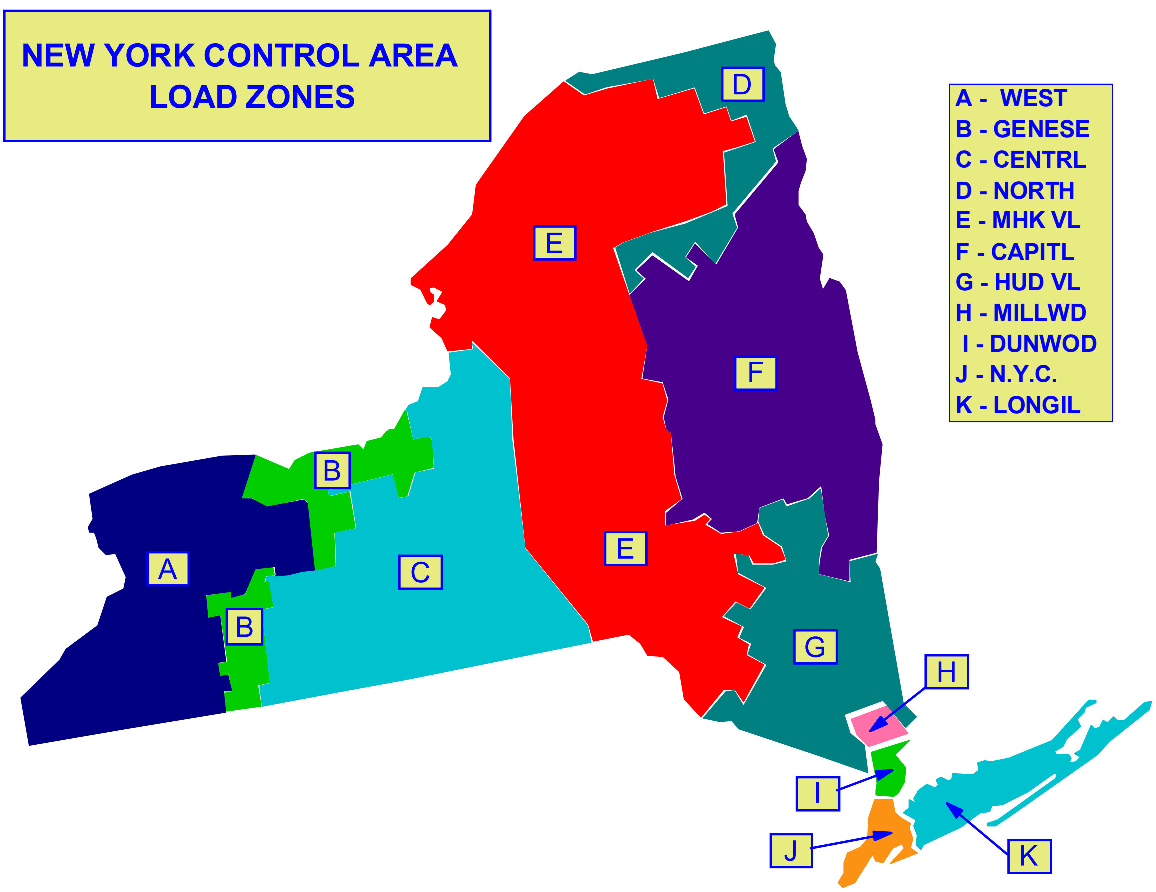
Finally, the study determined that almost 9% of the potential upstate wind energy production will be “bottled” or not deliverable because of local transmission limitations. The study identified feasible sets of transmission facility upgrades to eliminate the transmission limitations. These upgrades were evaluated to determine how much of the wind energy that was undeliverable would be deliverable if the transmission limitations were removed. Additional alternatives were suggested and evaluated to address the significant levels of resource bottling that occurs in the Watertown vicinity. The suggested transmission upgrades and alternatives require a detailed physical review and economic evaluation before a final set of recommendations can be determined.

In addition to the findings presented in this Executive Summary, the main body of the report offers other findings as well as additional support for the findings presented in the executive summary. The report also contains an update of the review of the European experience with variable generation that was part of the 2004 study and there are summaries of wind integration studies by the California ISO, the Ontario Power Authority in Canada and the Electric Reliability Council of Texas.

NYISO Wind Generation Study

1. Purpose

This document presents the results of a study of 8,000 MW of wind generation on the New York Control Area – see map below. The purpose of the study was two fold: 1) To update the GE study that was conducted in 2004 for wind generation up to 3,300 MW; and 2) To identify issues that will need to be addressed and initiatives that will be need to be undertaken to integrate several thousand MW of wind generation. The primary focus of the report is on the technical impacts of increasing the penetration of wind resources. The impact on production costs, locational marginal prices, congestion costs and uplift are presented based on the production costs simulations that were conducted. The study did not conduct nor did the study scope contemplate a full economic evaluation of the costs and benefits of wind generation.



2. Background

The implementation of policies and the adoption of regulations designed to encourage the development of renewable energy technologies is resulting in the significant growth in the installed base of wind generation in the New York Control Area (NYCA) as well as throughout the North America. Given wind generation's variable and less predictable nature and technology characteristics, industry experience and studies have indicated that large-scale wind generation has a unique set of impacts on power system operation. While these impacts may be relatively small at low penetration levels, as penetration levels increase, physical transmission system reinforcements and special bulk power system planning and operating practices may be required. Therefore, these potential impacts need to be fully understood to guarantee the reliable operation and planning of the New York Power System (NYPS).

In September of 2004, New York State adopted a Renewable Portfolio Standard that requires 25% of New York States' electricity needs be supplied by renewable resources by 2013. This requirement resulted in the New York Independent System Operator and the New York State Energy Research and Development Authority (NYSERDA) co-funding a study, which was designed to conduct a comprehensive assessment of wind technology, and to perform a detailed technical study to evaluate the impact of large-scale integration of wind generation on the NYPS. The study was conducted by GE Power System Energy Consulting in fall of 2003 and completed by the end of 2004 (i.e., "the 2004 Study").

The overall conclusion of that study was the expectation that the NYPS can reliably accommodate up to 10% penetration or 3,300 MW of wind generation with only minor adjustments and extensions to its existing planning, operation, and reliability practices – e.g., forecasting of wind plant output. Also, the finding that no major issues were found in the aggregate does not mean that the potential for significant local interconnection issues or engineering challenges specific to particular site would not be encountered. Such issues would need to be identified through the NYISO's interconnection and electric system planning processes. In addition, the NYISO will continue to evolve its operating and interconnection requirements to implement best practices.

Since the completion of the NYISO/NYSERDA wind study, a number of the recommendations contained in the report have been adopted such as a low voltage ride through standard and a centralized forecasting service for wind plants. Installed nameplate wind generation has now grown to in excess of 1,200 MW and the NYISO interconnection queue significantly exceeds the 3,300 MW that was studied in the 2004 Study. In addition, the cap on eligible wind generation exempt from under generation penalties and eligible to be fully compensated for over-generation was increased from 1,000 MW to 3,300 MW. Finally, the State of New York has increased its RPS standard to 30% by 2015.

3. Wind Plant Integration – Issues

As a result of these changing conditions and ongoing wind integration issues, the NYISO committed to study the impact of wind generation beyond 3,300 MW. As part of the study process the NYISO identified a set of issues that need to be addressed in order to continue the orderly and reliable integration of continuing growth in wind generation into the NYCA power grid and market operations. These issues include the following:

Transmission: Transmission plays a critical role in the large scale integration of variable generation. A significant amount of new transmission and/or enhanced utilization of existing transmission capability will be needed over the next several years to accommodate and integrate higher levels of wind generation.

System Flexibility: The bulk power system will experience higher magnitude ramping events and to accommodate the increased variability and uncertainty of variable generation the system will need to commit proportionately more dispatchable resources to maintain system flexibility. The resource planning and development frameworks must ensure that the bulk power system has the necessary quantity of flexible supply and demand resources necessary to accommodate generation – e.g., storage capability or off-peak load such as plug-in hybrid electric vehicles. Markets, pricing mechanisms and interconnection standards need to provide signals about the characteristics that are valued both to existing generators and to entities that are planning for new generation.

Operator Awareness and Practices: Enhancements are required to existing operator practices, techniques and decision support tools to increase the operator awareness and to enable the operation of the future bulk power systems with large scale penetration of wind generation. Wind generation must be visible to[4] and controllable by the system operator similar to any other power plant to allow the system operator to maintain reliability. Based on current experience with operating wind plants the NYISO has already developed a FERC approved wind resource management proposal which makes wind plants subject to dispatch signals when system constraints exist.

Forecasting: Short term forecasting techniques used for real time operation must be enhanced to more accurately predict the magnitude and phase (i.e. timing) of wind generation plant output. One area needing increased attention is being able to predict extreme weather events that could result in the rapid loss of wind generation – e.g., "high-speed wind cutout".

Wind Generation Plant Performance and Standards: Interconnection and generating plant standards must be enhanced to ensure that variable generating plant design and performance contribute to reliable operation of the power system.

System Models: Improved component model development, validation and standardization for all wind technologies are also required, especially for stability and transient analysis.

[4] The NYISO interconnection standards already require wind plants to be visible to system operators.

4. Study Tasks and Process

The study of wind penetrations in excess of 3,300 MW resulted in the following tasks:

Task 1: Develop wind generator penetration scenarios for selected study years including MW output profile and MW load profile.

Task 2: Develop and implement performance monitoring processes for operating wind generators.

Task 3: Update the review of the European experience conducted for the 2004 study with currently existing wind plants, and review the experiences and studies for wind plants in other regions of the US and Canada.

Task 4: Study the potential impacts on system operations of wind generators at various future levels of installed MW for the selected study years as it relates to regulation requirements and the overall impact on ramping.

Task 5: Evaluate the impact of the higher penetration of wind generation from a system planning perspective – including the evaluation of transmission limitations – by identifying specific transmission constraints (limiting element/contingency) for each project (or group of projects).

Task 6: Evaluate the impact of the higher penetration of wind generation on the overall system energy production by fuel types, locational based marginal prices (LBMP), congestion cost, operating reserves, regulation requirements, and load following requirements.

Task 7: Identify the impact of transmission constraints on wind energy that is not deliverable (i.e., "bottled") because of the transmission constraints and identify possible upgrades for the limiting elements/transmission facilities.

The technical analysis required by the study task includes a set of sequential steps that are needed to successfully conduct a comprehensive analysis of integrating wind into the grid as a function of penetration level. In addition to the traditional planning analysis and economic assessments, the integration of a variable generation resources requires the assessment of operational issues as well. Operational analyses in conjunction with traditional planning assessments are necessary to fully understand the overall technical implication and potential cost associated with integrating variable generation resources. This process includes the following steps:

Step 1: A determination of the interconnection point of the resources and potential output

Step 2: A thorough assessment of the transmission system to determine the contingencies and constraints that could adversely impact wind

Step 3: A statistical analysis of the interaction of load and wind as measured by the net load to determine the impact of variable wind resources on overall system variability and operational requirements

Step 4: Dispatch simulation with a production cost tool to determine the amount of wind that will be constrained off and the impact of wind on the overall dispatchablility such as plant commitment and economics of the system

Step 5: An identification and rank ordering of the transmission constraints that impact the dispatchablility of wind

Step 6: Development of transmission upgrades to relieve wind constraints for the various penetration levels of wind

Step 7: Redo step 4 with upgrades and needed operational adjustments determined in step 3 to determine the full impact

Step 8: Conduct a dynamic assessment to determine if the planned system with the higher levels of wind will satisfy stability criteria

Step 9: Conduct loss-of-load-expectation (LOLE) analysis to determine the impact of installed wind on system load carrying capability or reserve margin requirements.

5. Wind Study Results

5.1. Results for Task 1 - Study Assumptions:

This task resulted in three study years being selected. They are 2011, a near-in year; 2013 which is the target year of the 25% RPS; and 2018, which is the tenth year of the 2009 reliability planning cycle, and is also the first year of the Eastern Interconnection Wind Integration study being conducted by the National Renewable Energy Lab (NREL). The starting point or base assumptions for the wind study was the base case for the 2009 Comprehensive Reliability Plan[5] (CRP) for the transmission analysis. The starting point for the production cost simulations was the assumptions in the 2009 Congestion Assessment and Resource Integration Study[6] (CARIS).

Section 4.3.1 of the CARIS report presents the New York Control Area transfer limits that were used for the study including a Central East limit of 2,600 MW. The wind study used the nominal planning limit of 2,800 MW. Section 4.4 of the CARIS report presents the fuel costs assumptions that were used in the production costs simulations which was the GridView modeling tool used for the CARIS study. Section 4.5 of the CARIS report presents the emission costs that were used in the study. The cost for CO_2 or green house gas emissions are approximately $3.50 per ton in 2009 and increase to approximately $6.00 per ton in 2018, with 2013 at approximately $5.00 per ton.

For each of the years, two levels or scenarios of installed nameplate wind plant were developed. They are: 1) 3,500 MWs and 4,250 MWs for 2011 which represents approximately 10% and 12% of the projected peak for that year while 4,250 MWs would supply 6.5% of the forecast energy at a 30% capacity factor; 2) 4,250 MWs and 6,000 MWs for 2013 with 6,000 MWs equal to 17% of the projected peak for that year and 8.9% of forecast energy at a 30% capacity factor; and 3) 6,000 MWs and 8,000 MWs for 2018 while 8,000 MWs of wind is equal to 22.4% of the projected peak for that year and 11.6% of forecast energy at 30% capacity factor. AWS Truepower (formerly know as AWS Truewind) who is the contractor for the wind forecasting service, as well as a contractor to NREL for the Eastern Interconnection Wind Integration study, provided the wind output profiles required for the study.

5.2. Results for Task 2 - Wind Plant Performance Monitoring:

One of the observations made in the initial wind study was that much could be learned from operating wind plants as they came on line. To that end, the NYISO developed a reporting process for tracking the performance of operating wind plants. The report entitled: “Daily Wind Plant Performance Tracking Report” tracks the performance of wind plants on a daily basis for key metrics such as maximum coincident wind plant output, total output at the time of the system peak, Mwh generated, capacity factor, etc. Appendix A-1 contains the daily summary report for 2009.

Besides daily tracking of wind plant performance, the NYISO has experienced and analyzed rare events such as high-speed cutout which is the result of wind conditions that exceed the capability of the wind turbines causing them to shut down rapidly to protect the equipment. Wind plants can also ramp up quickly as the wind speed picks up suddenly. Wind plants may ramp up quickly as a thunder storm approaches a plant site and then shut down as wind exceeds the capability of the equipment. Figure 5.1 is an example of a high-speed cutout event that NYISO operations observed on June 10, 2008. The figure shows how a front containing thunderstorms moved from west to east affecting wind plants at different locations on the system. Wind plant output is

[5] http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/CRP__FINAL_5-19-09.pdf
[6] http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/CARIS_Final_Report_1-19-10.pdf

expressed as a percent of nameplate. For the first set of plants (red line) to encounter the front, the plants ramp up preceding the cutouts from 26% of nameplate to 61% of nameplate over 30 minutes and then ramp downs from cutouts to 5% of nameplate over 10 minutes. After the storm passes, the plants ramp back up to 82% of nameplate over 45 minutes. A similar pattern is observed later for the plants further to the east (green line).

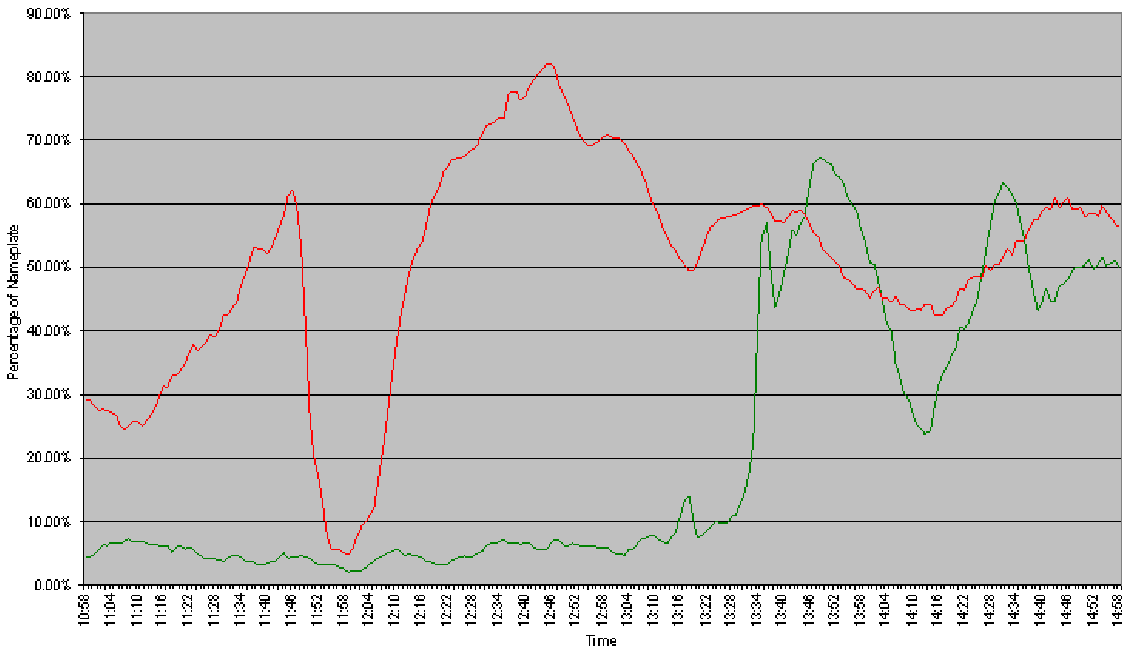


Figure 5.1: High-Speed Cutout Event approx. 12 noon on 6/10/08

In addition, the NYISO has observed the ability of wind plants to adjust the level of their output rapidly in response to changing system conditions which result in price changes. These operating experiences to date indicate a need to communicate dispatch commands to the wind plant operators on an as needed basis to maintain reliability especially as the amount of installed wind plant MWs increased. Experience with existing wind plants resulted in the NYISO moving forward with a resource management initiative to extend its market-based Security Constrained Economic Dispatch (SCED) systems to wind plants.

The integration of increased levels of wind will be facilitated by using the NYISO's market signals (e.g. location-based marginal prices) and the economic offers submitted by the generation resources, including wind plants, to address reliability issues rather than relying upon manual intervention by operators.

Based on the offers submitted by each wind plant and other resources, SCED will determine the most economic mix of resources to meet real-time security constraints. Allowing wind plants to indicate their economic willingness to operate reduces the need for the NYISO or local system operators to take less efficient, out-of-market actions to protect the reliability of the system.

This results in better utilization of wind plant output while maintaining a secure, reliable system and more accurate LBMP signals.

This wind on dispatch initiative was developed in conjunction with stakeholders, approved by the Federal Energy Regulatory Commission, and has now been implemented.

5.3. Results for Task 3 - European, US and Canada Experience with Wind Plants:

The purpose of Task 3 was review of the European experience with existing wind plants and review the experiences and studies for wind plants in other regions of the US and Canada that have been conducted since the 2004 Study. Europe is the region of the world that has highest penetration of wind. The NYISO contracted with Dr. Thomas Ackermann of Energynautics GmbH to provide a report of Europe's most recent operating experience with wind. Also, the NYISO reviewed the most recent study work from California, Texas and the Province of Ontario. In addition, the NYISO is participating in the North American Electric Reliability Councils, Inc. (NERC) Integration of Variable Generation Task Force (IVGTF) as well as what is known as the "Eastern Interconnection Wind Integration Study". This study includes Department of Energy/NREL, MISO (study lead), NYISO, PJM, SPP, and TVA.

The primary findings of the report prepared by Dr. Ackerman are as follows:

Europe shows that high/very high wind penetration levels are possible, but those high penetration levels are driven by energy policy (subsidies) and not economics for the most part. This also applies to power system integration issues.

Wind power can be successfully included in markets (Spain/UK).

Transmission helps to achieve benefits of aggregating large-scale wind power development and provides improved system balancing services. This is achieved by making better use of physically available transmission capacity and upgrading and expanding transmission systems. High wind penetrations may also require improvements in grid internal transmission capacity.

European regulators and Transmission System Operators (TSOs) have developed a willingness to learn and question existing rules as well as to adjust rules and regulations. In addition, most European countries have shown a flexibility to adjust their energy policy, rules and regulations depending on the technical and economical development in order to create a low-risk environment for renewable energy projects, without allowing windfall profits as it is very difficult to get all relevant regulatory details right at the first attempt. This flexibility for change has been based on a continuous dialogue between policy makers, regulators, network companies and the renewable energy lobby.

Both load and generation benefit from the statistics of large numbers as they are aggregated over larger geographical areas. Larger balancing areas make wind plant aggregation possible. The forecasting accuracy improves as the geographic scope of the forecast increases; due to the decrease in correlation of wind plant output with distance, the variability of the output decreases as more plants are aggregated. On a shorter-term time scale, this translates into a reduction in reserve requirements; on a longer-term time scale, it produces some smoothing effects on the capacity value. Larger balancing areas or coordination agreements with neighboring areas also give access to more balancing units such as hydro units and the ability to bank energy.

Integrating wind generation information into real-time system operations and with updated forecasts for the day-ahead operations will help manage the variability and forecast errors of wind power. Well-functioning hour-ahead and day-ahead markets including having wind plants respond to dispatch signals can help to more cost-effectively provide balancing energy required by the variable-output wind plants and maintain system security.

Appendix B-1 provides an expanded summary of Dr Ackermann's findings.

The overall conclusion from the California study sponsored by the California ISO (CAL-ISO) can best be summarized by the words of California ISO President & CEO Yakout Mansour: "The good news is that this study shows the feasibility of maintaining reliable electric service with the expected level of intermittent renewable resources associated with the current 20% RPS, provided that existing generation remains available to provide back-up generation and essential reliability services. The cautionary news is the "provided" part of our conclusion." Appendix B-2 provides an expanded summary of the CAL-ISO study.

The overall conclusion from the Texas study sponsored by the Electric Reliability Council of Texas (ERCOT) is that through 5,000 MW of wind generation capacity, approximately the level of wind capacity presently in ERCOT (on the order of 5% of the peak), wind generation has limited impact on the system. Its variability barely rises above the inherent variability caused by system loads. At 10,000 MW wind generation capacity, the impacts become more noticeable. By 15,000 MW (on the order of 20% of the peak), the operational issues posed by wind generation will become a significant focus in ERCOT system operations. However, the impacts can be addressed by existing technology and operational attention, without requiring any radical alteration of operations. Appendix B-3 provides an expanded summary of the ERCOT study.

The Ontario study was sponsored by the Ontario Power Authority (OPA). This study concluded that for all wind scenarios, the increase in hourly and multi-hourly variability, as measured by σ, due to wind is relatively small (not more than 10% for any scenario). From an hourly scheduling point of view, even 10,000 MW of wind would not push the envelope much further beyond the current operating point. However, the amount and magnitudes of extreme one-hour and multihour net-load changes are significantly greater with high wind penetration. With the addition of 10,000 MW of wind, the maximum one-hour net-load rise increases by 34%, and the maximum one-hour net-load drop increases by 30%. This data indicates that with large amounts of wind, much more one-hour ramping capability is needed for secure operation. Clearly the longest sustained ramping (up and down) occurs during the summer morning load rise and evening load decline periods. During these periods (and others) the units may need to ramp continually over three or more hours. For the year 2020 load with 10,000 MW of wind scenario, the maximum positive three-hour load-wind delta increases by 17% and the maximum negative three-hour delta increases by 33%. The detailed results clearly illustrate the fact that units will have to undergo sustained three-hour ramping more often, and ramp further with the addition of large amounts of wind. Appendix B-4 provides an expanded summary of the OPA study.

As noted above, the NYISO also participated in NERC's Integration of Variable Generation Task Force. In December 2008 in anticipation of the growth of wind and other variable generation, NERC's Planning and Operating Committees created the Integration of Variable Generation Task Force charged with preparing a report to include: 1) philosophical and technical considerations for integrating variable resources into the Interconnection, and 2) specific recommendations for practices and requirements, including reliability standards, that cover the planning, operations planning, and real-time operating timeframes.

The goals of this report were to:

Raise industry awareness and the understanding of characteristics of variable generation

Raise industry awareness and the understanding of the challenges associated with large scale integration of variable generation

Investigate the impacts on traditional approaches used by system planners and operators to plan, design and operate the power system

Scan NERC Standards, FERC rules and business practices to identify possible gaps and future requirements to ensure bulk power system reliability in light of large scale integration of variable resource

The final document was issued on April 16, 2009 and is available on the NERC website[7].

In conclusion, the primary insights that can be drawn from the review of the European and other studies and the NERC draft report are as follows:

[7] http://www.nerc.com/files/IVGTF_Report_041609.pdf

Higher levels of installed wind generation above the 3,300 MW from a system operation perspective are feasible.

Achieving a higher level of wind penetration will most likely require the implementation of enhancements to and extension of existing operating protocols, procedures and reliability standards.

The major areas of ongoing concern that are common across all regions tend to focus on the following questions:

Will there be sufficient transmission infrastructure to integrate the higher penetrations of wind?

Will sufficient resources be available when the higher penetration of wind generation are achieved to provide the operational flexibility that will be needed with higher penetration of variable generation?

Validation of wind turbine models needed for system studies.

5.4. Results for Task 4 - Assessing the Impact of Wind Plants on System Operations:

5.4.1. Introduction

The focus of Task 4 is to study the impacts on system operations of the penetration of installed wind plants above 3,300 MWs. The impact of increasing wind penetration from its current installed nameplate of 1,274 MW up to 8,000 MW on such operational parameters as regulation requirements, load following, ramping and operating reserves were evaluated. Power systems are dynamic, existing in a continuously changing environment, and are impacted by factors that change from moments-to-seconds, seconds-to-minutes, minutes-to-hours, seasonally and year-to-year. In the various time frames of operation, balance must be maintained between the load on the system and the available generation. In the very short timeframe (seconds-to-minutes), bulk power system reliability is almost entirely maintained by automatic equipment and control systems such as automatic generation control (AGC). In the intermediate to longer timeframes system operators and operational planners are the primary keys to maintaining system reliability. Figure 5.2 displays the various timescales that impact power systems, the operating and planning processes they impact and the associated issues that need to be addressed.

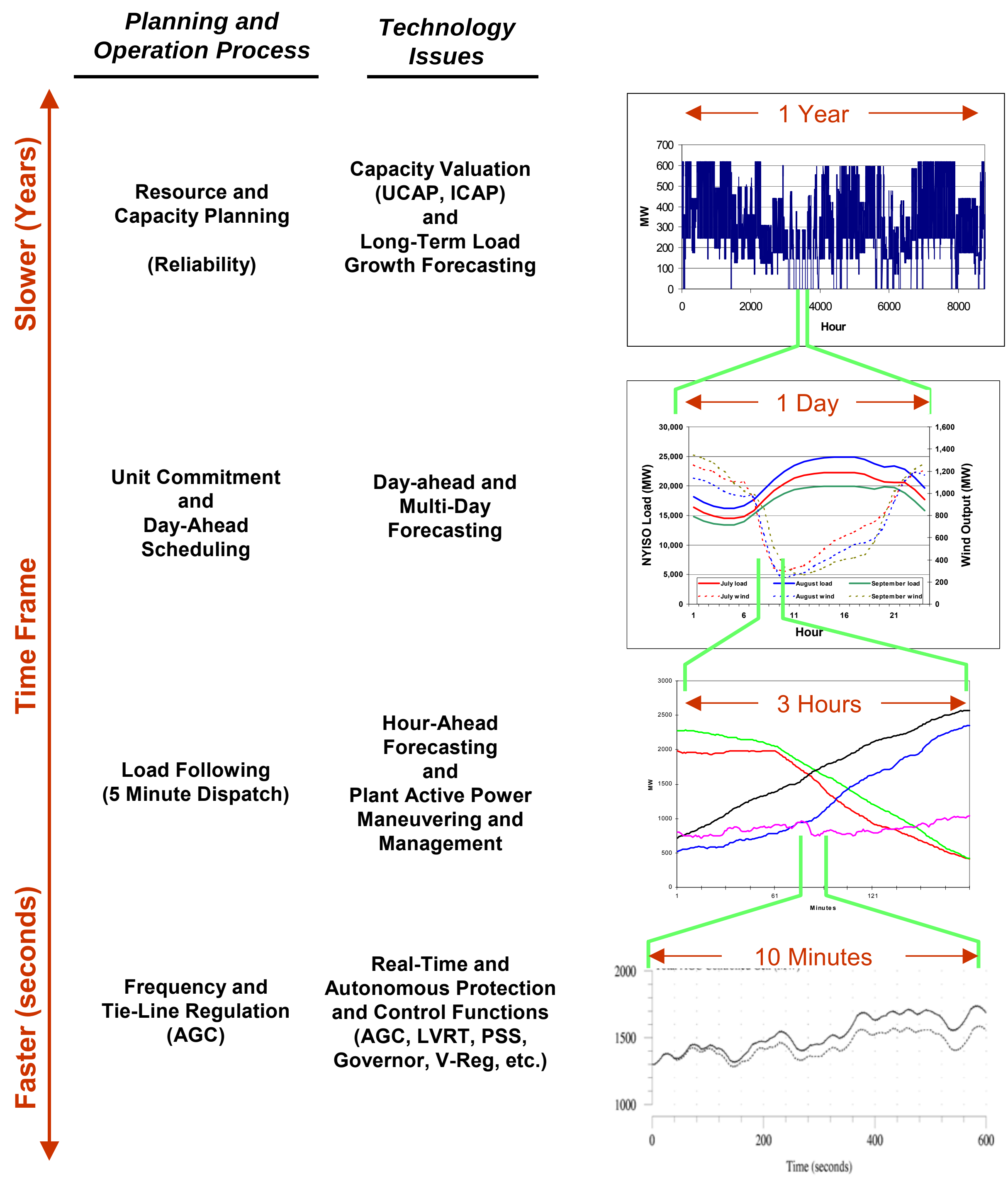


Figure 5.2: Power System Time Scales

The fact that the load is constantly changing means that its variability must first be understood in order to assess the impact of another variable element, (such as wind), on system operation. Statistics is an extremely useful tool for understanding and describing variation in data. The analysis of system variability for various time scales from minutes to hours is being conducted to assess the impact on such operating parameters as regulation, load following, operating reserves, ramping, and scheduling. Figure 5.2 presents the various time scales and the technology issues that are important in that time frame.

AWS Truepower developed wind profiles based on 2004 through 2006 wind data for approximately 35 sites in NY. Utilizing operating wind plants and proposed projects in the interconnection queue the NYISO then developed simulated outputs for wind plants ranging from an installed base of nameplate wind of 3,500 MW up to 8,000 MW of installed nameplate wind. The intermediate steps were nominally 4,250 MW and 6,000 MW. The wind plants from the NYISO's interconnection queue that are included in the study are listed in Table 5-1.

Table 5-1: List of Wind Plant Units

Units that Compose the 1275 MW Case

Queue #	Station/Unit	Nameplate Rating (MW)	Zone
I/S	Altona Windfield	99.0	D
I/S	Bliss Windfield	100.5	A
I/S	Canandaigua II	42.5	C
I/S	Canandaigua Wind Farm	82.5	C
I/S	Chateaugay Windpark	106.5	D
I/S	Clinton Windfield	100.5	D
I/S	Ellenburg Windfield	81.0	D
I/S	Fenner Wind Power	30.0	C
I/S	High Sheldon Windfarm	113.0	C
I/S	Madison Wind Power	11.6	E
I/S	Maple Ridge 1	231.0	E
I/S	Maple Ridge 2	90.7	E
I/S	Munnsville Wind Power	34.5	E
I/S	Steel Winds	20.0	A
I/S	Wethersfield 230kV	126.0	C
I/S	Wethersfield Wind Power	6.6	B

Units Added to Create the 4250 MW Case

Queue #	Station/Unit	Nameplate Rating (MW)	Zone
113	Prattsburgh Wind Park	55.5	C
119	Prattsburgh Wind Farm	79.5	C
152	Moresville Energy Center	129.0	E
155	Canisteo Hills Windfarm	148.5	C
156	Fairfield Wind Project	120.0	E
157	Orion Energy NY I	100	E
160	Jericho Rise Wind Farm	101.2	D
161	Marble River Wind Farm	88.2	D
166	St. Lawrence Wind Farm	130.0	E
168	Dairy Hills Wind Farm	120.0	C
169	Alabama Ledge Wind Farm	79.2	B
171	Marble River II Wind Farm	140.7	D
182	Howard Wind	62.5	C
186	Jordanville Wind	136.0	E
189	Clayton Wind	126.0	E
197	Tug Hill	78.0	E
198	New Grange Wind Farm	79.9	A

203	GenWy Wind Farm	478.5	A
207	Cape Vincent	210.0	E
220	Armenia Mountain I	175.0	C
221	Armenia Mountain II	75.0	C
222	Ball Hill Windpark	99	A
234	Steel Winds II	60	A
237	Allegany Windfield	79	A

Units Added to Create the 6000 MW Case

Queue #	Station/Unit	Nameplate Rating (MW)	Zone
150	Cherry Valley Wind Power	70	F
178	Allegany Wind	79.0	A
179	Cherry Hill Windpark	102	D
187	North Slope Wind	109.5	D
215	Noble Burke Windpower	120	D
217	Cherry Flats	90	C
227	Orleans Wind	120	B
236	Dean Wind	150	C
238	Tonawanda Creek Wind	75	B
239	Western Door Wind	100	C
240	Farmersville Windpark	100	A
246	Dutch Gap Wind	250	E
254	Ripley-Westfield Wind	124.8	A
256	Niagara Shore Wind	70.5	A
263	Stony Creek Wind Farm	142.5	C
241	Chateaugay II Windpark	19.5	D

Units Added to Create the 8000 MW Case

Queue #	Station/Unit	Nameplate Rating (MW)	Zone
270	Hounsfield Wind	268.8	C
282	Concord Wind	101.2	A
285	Machias I	79.2	A
297	Ashford Wind	19.9	A
298	Leicester Wind	57	B
301	Hamlin Wind Farm	80	B
327	Offshore Wind	1400	J, K

Summary of Nameplate Rating by Case for each Zone (MW)

Case	A	B	C	D	E	F	J, K	Total
1275	121	7	394	387	368			1276
4250	917	86	1110	717	1397			4227
6000	1291	281	1593	1068	1647	70		5949
8000	1492	418	1861	1068	1647	70	1400	7955

The simulations were done based on 2005 and 2006 wind data. The AWS site closest to the existing wind or proposed wind plant site was utilized for developing a specific output profile for that wind plant. Output profiles based on 2005 and 2006 wind data were developed for each wind plant. The first 1,500 MW of wind was simulated with wind turbines with a hub height of 80 meters and balance with a hub height of 100 meters. Simulated wind plant output was developed for one minute, ten minute and one hour for selected sites in NY. Load profiles were developed internally.

APPENDIX D: RESUMES

On the following pages, we provide resumes for Bob Fagan, Dr. Tommy Vitolo, and Patrick Luckow.

Robert M. Fagan

Principal Associate
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rfagan@synapse-energy.com

SUMMARY

Mechanical engineer and energy economics analyst with over 25 years of experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission, wholesale electricity markets, renewable resource alternatives and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures; the extent of competitiveness of such structures.
- Potential for and operational effects of wind and solar power integration into utility systems; modeling of such effects.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives, financial and physical transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation.
- FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based tools, industry standard tools for production cost and resource expansion, building energy analysis, understanding of power flow simulation fundamentals).
- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.

- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. 2004 – Present. Principal Associate
Responsibilities include consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management. Provide expert witness testimony on various wholesale and retail electricity industry issues. Specific project experience includes the following:

- Analysis of PJM and MISO wind integration and related transmission planning and resource adequacy issues.
- Analysis of California renewable energy integration issues, local and system capacity requirements, and related long-term procurement policies.
- Analysis of Nova Scotia resource policies including effects of potential new hydroelectric supplies from Newfoundland; analysis of new transmission supplies of Maritimes area energy into the New England region.
- Analysis of Eastern Interconnection Planning Collaborative processes, including modeling structure and inputs assumptions for demand, supply and transmission resources. Expanded analyses of the results of the EIPC Phase II Report on transmission and resource expansion.
- Analysis of need for transmission facilities in Maine, Ontario, Pennsylvania, Virginia, Minnesota.
- Ongoing analysis of wholesale and retail energy and capacity market issues in New Jersey, including assessment of BGS supply alternatives and demand response options.
- Analysis of PJM transmission-related issues, including cost allocation, need for new facilities and PJM's economic modeling of new transmission effects on PJM energy market.
- Ongoing analysis of utility-sponsored energy efficiency programs in Rhode Island as part of the Rhode Island DSM Collaborative; and ongoing analysis of the energy efficiency programs of New Jersey Clean Energy Program (CEP) and various utility-sponsored efficiency programs (RGGI programs).
- Analysis of California renewable integration issues for achieving 33% renewable energy penetration by 2020, especially modeling constructs and input assumptions.
- Analysis of proposals in Maine for utility companies to withdraw from the ISO-NE RTO.
- Analysis of utility planning and demand-side management issues in Delaware.
- Analysis of effect of increasing the system benefits charge (SBC) in Maine to increase procurement of energy efficiency and DSM resources; analysis of impact of DSM on transmission and distribution reinforcement need.
- Evaluation of wind energy potential and economics, related transmission issues, and resource planning in Minnesota, Iowa, Indiana, and Missouri; in particular in relation to alternatives to newly proposed coal-fired power plants in MN, IA and IN.
- Analysis of need for newly proposed transmission in Pennsylvania and Ontario.
- Evaluation of wind energy "firming" premium in BC Hydro Energy Call in British Columbia.

- Evaluation of pollutant emission reduction plans and the introduction of an open access transmission tariff in Nova Scotia.
- Evaluation of the merger of Duke and Cinergy with respect to Indiana ratepayer impacts.
- Review of the termination of a Joint Generation Dispatch Agreement between sister companies of Cinergy.
- Assessment of the potential for an interstate transfer of a DSM resource between the desert southwest and California, and the transmission system impacts associated with the resource.
- Analysis of various transmission system and market power issues associated with the proposed Exelon-PSEG merger.
- Assessment of market power and transmission issues associated with the proposed use of an auction mechanism to supply standard offer power to ComEd native load customers.
- Review and analysis of the impacts of a proposed second 345 kV tie to New Brunswick from Maine on northern Maine customers.

Tabors Caramanis & Associates, Cambridge, MA 1996 -2004. Senior Associate.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.
- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.
- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.
- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC’s SMD NOPR and the application of FERC’s Order 2000 on RTO development.
- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA, 1992-1996. **Associate**. Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations. Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI, 1987-1992. **Senior Commercial/Industrial Energy Specialist**. Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated customer participation in utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY 1985-1986. Facilities Engineer. Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI, 1981-1984. Supervisor of Operations and Maintenance. Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, M.A. Energy and Environmental Studies, 1992
Resource Economics, Ecological Economics, Econometric Modeling

Clarkson University, B.S. Mechanical Engineering, 1981
Thermal Sciences

Additional Professional Training and Academic Coursework
Utility Wind Integration Group - Short Course on Integration and Interconnection of Wind Power Plants Into Electric Power Systems (2006).

Regulatory and Legal Aspects of Electric Power Systems – Short Course – University of Texas at Austin (1998)

Illuminating Engineering Society courses in lighting design (1989).

Coursework in Solar Engineering; Building System Controls; and Cogeneration at Worcester Polytechnic Institute and Northeastern University (1984, 1988-89).

Graduate Coursework in Mechanical and Aerospace Engineering – Polytechnic Institute of New York (1985-1986)

SUMMARY OF TESTIMONY

California Public Utilities Commission. Reply and Rebuttal testimony in Track 4 of the proceeding RM.12-03-014, "Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans", filed on September 30, 2013 (Reply) and October 14, 2013 (Rebuttal). Testimony filed on behalf of the California Office of Ratepayer Advocate. Track 4 investigated the local reliability impacts of a potential long-term outage at the San Onofre Nuclear Power Station (SONGS).

Nova Scotia Utility and Review Board (UARB). Direct testimony before the UARB sponsoring the multi-authored report "Economic Analysis of Maritime Link and Alternatives: Complying with Nova Scotia's Greenhouse Gas Regulations, Renewable Energy Standard, and Other Regulations in a Least-Cost Manner for Nova Scotia Power Ratepayers", report dated April 18, 2013. Prepared for the Board Counsel to the Nova Scotia Utility and Review Board, jointly authored by Bob Fagan, Rachel Wilson, Nehal Divekar, David White, Kenji Takahashi, and Thomas Vitolo. Nova Scotia UARB Matter No. M05419. Testimony date June 5, 2013.

California Public Utilities Commission. Direct and Reply testimony in Track 1 of the proceeding RM.12-03-014, "Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans", filed on June 25, 2012 (direct) and July 23, 2012 (reply). Testimony filed on behalf of the California Division of Ratepayer Advocate. Track 1 investigated the long-term local capacity procurement requirements for the three California Investor-Owned Utilities.

California Public Utilities Commission. Supplemental testimony in the proceeding A.11.05.023, "Application of San Diego Gas & Electric Company for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power." May, 2012. Testimony filed on behalf of the California Division of Ratepayer Advocate. This docket investigated the long-term resource adequacy and resource procurement requirements for the San Diego region.

Prince Edward Island Regulatory and Appeals Commission
Jointly-authored (with Nehal Divekar) Expert report, "Analysis of the Proposed Ottawa Street – Bedeque 138 kV Transmission Line Project, November 5, 2012. Filed in Docket UE30402 - Summerside Electric - Application for the Approval of Transmission Services connecting Summerside Electric's Ottawa Street substation to Maritime Electric Company Limited's Bedeque substation.

New Jersey Board of Public Utilities. Direct testimony in the matter of the petition of Pivotal Utility Holdings, Inc. D/B/A Elizabethtown gas for authority to extend the term of energy efficiency programs with certain modifications and approval of associated cost recovery. Docket No. GO11070399. Hearing conducted December 16, 2011.

New Jersey Board of Public Utilities. Oral testimony before the Board, on certain aspects of the Board's inquiry into capacity and transmission interconnection issues, Docket No. EO11050309. Hearing conducted October 14, 2011.

New Jersey Board of Public Utilities. Certification before the Board, I/M/O a Generic Stakeholder Proceeding To Consider Prospective Standards for Gas Distribution Utility Rate Discounts and Associated Contract Terms, Docket Nos. GR10100761 and ER10100762. Issues addressed included SBC charge rates associated with gas generation. Testimony filed January 28, 2011.

New Jersey Board of Public Utilities. Oral testimony before the Board, on certain aspects of the Basic Generation Service (BGS) procurement plan for service beginning June 1, 2011. Docket No. ER10040287. Hearing conducted September, 2010.

Virginia State Corporation Commission. Pre-filed Direct Testimony filed October 23, 2009 on behalf of the Sierra Club on the need for the Potomac-Appalachian Transmission Highline (PATH), a 765 kV proposed transmission line across West Virginia, Virginia and Maryland. Proceedings are currently terminated as filing party (American Electric Power and Allegheny Power) withdrew the application pending additional RTEP analyses by PJM scheduled for 2010. Testimony addressed issues of need and modeling of DSM resources as part of the PJM RTEP planning processes.

Pennsylvania Public Utility Commission. Direct Testimony filed June 30, 2009 on behalf of the Pennsylvania Office of Consumer Advocate on the need for the Susquehanna-Roseland 500 kv proposed transmission line in portions of Luckawanna, Luzerne, Monroe, Pike, and Wayne counties. Testimony assessed the modeling for the proposed line, including load forecasts, energy efficiency resources, and demand response resources. Docket number A-2009-2082652. Surrebuttal testimony filed August 24, 2009.

Delaware Public Service Commission. Report on Behalf of the Staff of the Delaware Public Service Commission, filed in Docket No. 07-20, Delmarva's IRP docket, "Review of Delmarva Power & Light Company's Integrated Resource Plan", April 2, 2009. Jointly authored with Alice Napoleon, William Steinhurst, David White, and Kenji Takahashi of Synapse Energy Economics.

State of Maine Public Utilities Commission. Pre-filed Direct Testimony on the Application of Central Maine Power for a Certificate of Public Convenience and Necessity for the proposed Maine Power Reliability Project (MPRP), a $1.55 billion transmission enhancement project. Direct testimony focus on the non-transmission alternatives analysis conducted on behalf of CMP. Maine PUC Docket 2008-255, filed January 12, 2009 (direct) and surrebuttal (February 2, 2010) on behalf of the Maine Office of Public Advocate. Docket proceeding 2008-255, hearings completed in February 2010.

New Jersey Board of Public Utilities. Oral testimony before the Board, jointly with Bruce Biewald, on certain aspects of the Basic Generation Service (BGS) procurement plan for service beginning June 1, 2009. Docket No. ER08050310. Hearing conducted on September 29, 2008.

Wisconsin Public Service Commission. Direct and Surrebuttal Testimony in Docket 6680-CE-170 on behalf of Clean Wisconsin in the matter of an application by Wisconsin Power and Light for a CPCN for construction of a 300 MW coal plant. The testimony focused on the alternative energy options available with wind power, and the effect of the MISO RTO in helping provide capacity and energy to the Wisconsin area reliably without needed the proposed coal plant. The CPCN was denied by the WPSC in December 2008. Testimony filed in August (Direct) and September (Surrebuttal), 2008.

Ontario Energy Board. Pre-Filed Direct Testimony filed on behalf of Pollution Probe in the matter of the Examination and Critique of Demand Response and Combined Heat and Power Aspects of the Ontario Power Authority's Integrated Power System Plan and Procurement Process, Docket EB-2007-0707. The testimony addressed issues associated with the planned levels of procurement of demand response, combined heat and power, and NUG resources as part of Ontario Power Authority's long-term integrated planning process. Testimony filed on August 1, 2008. Docket is open; additional Power System Plan and Procurement filings expected from the Ontario Power Authority.

Ontario Energy Board. Direct and Supplemental Testimony filed jointly with Mr. Peter Lanzalotta on behalf of Pollution Probe in the matter of Hydro One Networks Inc. application to construct a new 500 kV transmission line between the Bruce Power complex and the town of Milton, Ontario. Docket EB-2007-0050. The testimony addressed issues of congestion (locked-in energy) modeling, need, and series compensation and generation rejection alternatives to the proposed line. Testimony filed on April 18, 2008 (Direct) and May 15, 2008 (Supplemental).

Federal Energy Regulatory Commission. Direct and Rebuttal Testimony on PJM Regional Transmission Expansion Plan (RTEP) Cost Allocation issues in Dockets ER06-456, ER06-954, ER06-1271, ER07-424, EL07-57, ER06-880, et al. The testimony addressed merchant transmission cost allocation issues. Testimony filed on behalf of the New Jersey Department of the Public Advocate, Ratepayer Division. Testimony filed on January 23, 2008 (Direct) and April 16, 2008 (Rebuttal).

Minnesota Public Utilities Commission. Supplemental Testimony and Supplemental Rebuttal Testimony on applicants' estimates of DSM savings in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal. In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275. Testimony filed December 21, 2007 (Supplemental) and January 16, 2008 (Supplemental Rebuttal).

Pennsylvania Public Utility Commission. Direct testimony filed before the Commission on the effect of demand-side management on the need for a transmission line and the level of consideration of potential carbon regulation on PJM's analysis of need for the TrAIL transmission line. Docket Nos. A-110172 *et al*. Testimony filed October 31, 2007.

Iowa Public Utilities Board. Direct testimony filed before the Board on wind energy assessment in Interstate Power and Light's resource plans and its relationship to a proposed coal plant in Iowa. Docket No. GCU-07-01. Testimony filed October 21, 2007.

New Jersey Board of Public Utilities. Direct testimony before the Board on certain aspects of PSE&G's proposal to use ratepayer funding to finance a solar photovoltaic panel initiative in support of the State's solar RPS. Docket No. EO07040278. Testimony filed September 21, 2007.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing a proposed Duke – Vectren IGCC coal plant. Testimony focused on wind power potential in Indiana. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 43114 May 14, 2007.

State of Maine Public Utilities Commission. Pre-filed testimony on the ability of DSM and distributed generation potential to reduce local supply area reinforcement needs. Testimony filed before the Commission on a Request for Certificate of Public Convenience and Necessity to Build a 115 kV Transmission Line between Saco and Old Orchard Beach. Testimony filed jointly with Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2006-487, February 27, 2007.

Minnesota Public Utilities Commission. Rebuttal Testimony on wind energy potential and related transmission issues in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal. In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275. December 8, 2006.

British Columbia Utilities Commission. In the Matter of BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan. Pre-filed Evidence filed on behalf of the Sierra Club (BC Chapter), Sustainable Energy Association of BC, and Peace Valley Environment Association. October 6, 2006. Testimony addressing the "firming premium" associated with 2006 Call energy, liquidated damages provisions, and wind integration studies.

Maine Joint Legislative Committee on Utilities, Energy and Transportation. Testimony before the Committee in support of an Act to Encourage Energy Efficiency (LD 1931) on behalf of the Maine Natural Resources Council, February 9, 2006. The testimony and related analysis focused on the costs and benefits of increasing the system benefits charge to increase the level of energy efficiency installations by Efficiency Maine.

Nova Scotia Utility and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of Air Emissions Strategy Capital Projects. Filed Jaunary 30, 2006. The testimony addressed the application for approval of installation of a flue gas desulphurization system at NSPI's Lingan station and a review of alternatives to comply with provincial emission regulations.

New Jersey Board of Public Utilities. Direct and Surrebuttal Testimony filed before the Commission addressing the Joint Petition Of Public Service Electric and Gas Company And

Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations (the proposed merger), BPU Docket EM05020106. Joint Testimony with Bruce Biewald and David Schlissel. Filed on behalf of the New Jersey Division of the Ratepayer Advocate, November 14, 2005 (direct) and December 27, 2005 (surrebuttal).

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing the proposed Duke – Cinergy merger. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 42873, November 8, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Ameren's proposed competitive procurement auction (CPA). Testimony filed on behalf of the Illinois Citizens Utility Board in Dockets 05-0160, 05-0161, 05-0162. Direct Testimony filed June 15, 2005; Rebuttal Testimony filed August 10, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Commonwealth Edison's proposed BUS (Basic Utility Service) competitive auction procurement. Testimony filed on behalf of the Illinois Citizens Utility Board and the Cook County State's Attorney's Office in Docket 05-0159. Direct Testimony filed June 8, 2005; Rebuttal Testimony filed August 3, 2005.

Indiana Utility Regulatory Commission. Responsive Testimony filed before the Commission addressing a proposed Settlement Agreement between PSI and other parties in respect of issues surrounding the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Consolidated Causes No. 38707 FAC 61S1, 41954, and 42359-S1, August 31, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission in a Fuel Adjustment Clause (FAC) Proceeding concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E, and related issues of PSI lost revenues from inter-company energy pricing policies. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 38707 FAC 61S1, May 23, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 41954, April 21, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Eastern Maine Electric Cooperative, Inc.'s Petition for a Finding of Public Convenience and Necessity to Purchase 15 MW of Transmission Capacity from New Brunswick Power and for Related Approvals. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2005-17, July 19, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and

Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2004-538 Phase II, April 14, 2005.

Nova Scotia Utility and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). Filed April 5, 2005. The testimony addressed various aspects of OATTs and FERC's *pro forma* Order 888 OATT.

Texas Public Utilities Commission. Testimony filed before the Texas PUC in Docket No. 30485 on behalf of the Gulf Coast Coalition of Cities on CenterPoint Energy Houston Electric, LLC. Application for a Financing Order, January 7, 2005. The testimony addressed excess mitigation credits associated with CenterPoint's stranded cost recovery.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-2002-0120, et al., Review of the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response To Phase I Questions Concerning the Transmission System Code and Related Matters, October 31, 2002, on behalf of TransAlta Corporation; and Reply Comments for same, November 21, 2002. Related direct and reply filings in response to the Ontario Energy Board's "Preliminary Propositions" on TSC issues in May and June, 2003.

Alberta Energy and Utilities Board. Testimony filed before the Alberta Energy and Utilities Board, in the Matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate Application, no. 2000135, pertaining to Supply Transmission Service charge proposals. Joint testimony filed with Dr. Richard D. Tabors. March 28, 2001. Testimony filed on behalf of the Alberta Buyers Coalition.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-1999-0044, Critique of Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for Alternative Rate Design, January 17, 2000. Testimony filed on behalf of the Independent Power Producer's Society of Ontario.

PAPERS, PUBLICATIONS AND PRESENTATIONS

Fagan B., J. Fisher, B. Biewald, *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process.* Synapse Energy Economics for the Sustainable FERC Project, July 2013.

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Fagan R., Chang M., P. Knight, M. Schultz, T. Comings, E. Hausman, R. Wilson, *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region.* Synapse Energy Economics for Eergy Future Coalition, August 2012.

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Peterson P., E. Hausman, R. Fagan, V. Sabodash, *Synapse Report and Ohio Comments in Case No. 09-09-EL-COI, "The Value of Continued Participation in RTOs.* Synapse Energy Economics for Ohio Consumers' Counsel, May 2009.

Hornby R., J. Loiter, P. Mosenthal, T. Franks, R. Fagan, D. White, *Review of AmerenUE February 2008 Integrated Resource Plan*. Synaspe Energy Economics for Missouri Department of Natural Resources, June 2008.

Hausman E., R. Fagan, D. White, K.Takahashi, A. Napoleon, *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers.* Synapse Energy Economics for American Public Power Association, February 2007.

Fagan R., T.Woolf, W. Steinhurst, B. Biewald, *Interstate Transfer of a DSM Resource: New Mexico DSM as an Alternative to Power from Mohave Generating Station.* Presented at the 2006 ACEEE Summer Study on Energy Efficiency in Buildings and published in the proceedings, August 2006

Fagan R., R. Tabors, *SMD and RTO West: Where are the Benefits for Alberta?* Keynote Paper prepared for the 9th Annual Conference of the Independent Power Producers Society of Alberta, March 2003.

Fagan R., *A Progressive Transmission Tariff Regime: The Impact of Net Billing*. Presentation at the Independent Power Producer Society of Ontario annual conference, November 1999.

Fagan R., R. Tabors, A. Zobian, N. Rao, R. Hornby, *Tariff Structure for an Independent Transmission Company*. TCA Working Paper 101-1099-0241, November 1999.

Fagan R., *Transmission Congestion Pricing Within and Around Ontario*. Presentation at the Canadian Transmission Restructuring Infocast Conference, Toronto, June 1999.

Fagan R., *The Restructured Ontario Electricity Generation Market and Stranded Costs*. An internal company report presented to the Ontario Ministry of Energy and Environment on behalf of Enron Capital and Trade Resources Canada Corp., February 1998.

Fagan R., *Alberta Legislated Hedges Briefing Note*. An internal company report presented to the Alberta Department of Energy on behalf of Enron Capital and Trade Resources Canada, January 1998.

Fagan R., *Generation Market Power in New England: Overall and on the Margin.* Presentation at Infocast Conference: New Developments in Northeast and Mid-Atlantic Wholesale Power Markets, Boston, June 1997.

Fagan R., *The Market for Power in New England: The Competitive Implications of Restructuring*. Prepared for the Office of the Attorney General, Commonwealth of Massachusetts by Tabors Caramanis & Associates with Charles River Associates, April 1996.

Fagan R., D. Gokhale, D. Levy, P. Spinney, G. Watkins, *Estimating DSM Impacts for Large Commercial and Industrial Electricity Users*. Presented at The Seventh International Energy Program Evaluation Conference, Chicago, Illinois, August 1995, and published in the Conference Proceedings.

Fagan R., G. Watkins, *Sampling Issues in Estimating DSM Savings: An Issue Paper for Commonwealth Electric*. Charles River Associates report for COM/Electric System, filed with the MA Dept. of Public Utilities (MDPU), April 1995, Docket # DPU 95-2/3-CC-l.

Fagan R., P. Spinney, *Demand-side Management Information Systems (DSMIS) Overview*. Electric Power Research Institute Technical Report TR-104707. Prepared by Charles River Associates for EPRI, January 1995.

Fagan R., P. Spinney, G. Watkins, *Impact Evaluation of Commonwealth Electric's Customized Rebate Program*. Charles River Associates initial and updated reports, April 1994, April 1995, and April 1996.1995 updated report filed with the MDPU, April 1995, Docket # DPU 95-2/3-CC-I. The initial report filed with the MDPU, April 1994.

Fagan R., P. Spinney *Northeast Utilities Energy Conscious Construction Program (Comprehensive Area): Level I and Level II Impact Evaluation Reports*. (CRA) and Abbe Bjorklund (Energy Investments). Charles River Associates reports prepared for Northeast Utilities, June and July 1994.

P. Spinney, J. Peloza authored, R. Fagan presented, *The Role of Trade Allies in C&I DSM Programs: A New Focus for Program Evaluation.* Charles River Associates and Wisconsin Electric Power Corp, presented at the Sixth International Energy Evaluation Conference, Chicago, Illinois, August 1993.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Associate, 2011–present.
Performs consulting, conducts research, and assists in writing testimony and reports on a wide range of issues relating to electric utilities, energy efficiency, electricity transmission and generation, consumer advocacy, environmental policy and compliance, and air emissions.

Jointown Group Co., Ltd., Wuhan, China. System Engineer Intern, Summer 2007.
Developed and implemented a modified (*s*,*S*) inventory management scheme for over 20,000 warehoused pharmaceutical products, resulting in more orders filled, lower carrying costs, and a reduction in the frequency of product expiration.

MIT Lincoln Laboratory, Division 6, Group 65, Lexington, MA. Research Assistant, 2003–2006.
Designed algorithm and implemented software to create autonomous wireless point-to-point topologies for aerial, land-based, and nautical vehicles as part of an Optical & RF Combined Link Experiment (ORCLE) funded by Defense Advanced Research Projects Agency (DARPA).

EDUCATION

Boston University, Boston, MA, Ph.D. Systems Engineering, 2011.
Developed algorithms to discover degree constrained minimum spanning trees in sparsely connected graphs.

Dublin City University, Dublin, Ireland, MS Financial and Industrial Mathematics, 2001.
Researched partial differential equations modeling fluid flow over an erodible bed.

North Carolina State University, Raleigh, North Carolina, BS Applied Mathematics, *Summa Cum Laude*, 2000; BS Computer Science, *Summa Cum Laude*, 1999; BS Economics, *Summa Cum Laude*, 1998.

ADDITIONAL EXPERIENCE

Teaching Experience: Graduate Teaching Fellow, Boston University College of Engineering, *Introduction to Engineering Computation*, 2009; Guest Lecturer, Boston University Department of Systems Engineering, *Case Studies in Inventory Management*, 2007-2008; Guest Lecturer, Boston University Department of Systems Engineering, Solving Linear Programs with CPLEX, 2003-2008.

Government Service: *Constable*, Brookline, MA, 2010-present; *Town Meeting Member*, Brookline, MA, 2007-present; *Bicycle Advisory Committee Member*, Brookline, MA, 2007-present.

PUBLICATIONS

Vitolo, T., J. Daniel, *Improving the Analysis of the Martin Drake Power Plant: How HDR's Study of Alternatives Related to Martin Drake's Future Can Be Improved.* Synapse Energy Economics for the Sierra Club, December 2013.

Vitolo, T., P. Luckow, J. Daniel, *Comments Regarding the Missouri 2013 IRP Updates of KCP&L and GMO.* Synapse Energy Economics for Earthjustice, August 2013.

Hornby R., P. Chernick, D. White, J. Rosenkranz, R. Denhardt, E. Stanton, J. Gifford, B. Grace, M. Chang, P. Luckow, T. Vitolo, P. Knight, B. Griffiths, B. Biewald, *Avoided Energy Supply Costs in New England: 2013 Report.* Synapse Energy Economics for the Avoided-Energy-Supply-Component (AESC) Study Group, July 2013.

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Vitolo, T., G. Keith, B. Biewald, T. Comings, E. Hausman, P. Knight, *Meeting Load with a Resource Mix Beyond Business as Usual: A regional examination of the hourly system operations and reliability implications for the United States electric power system with coal phased out and high penetrations of efficiency and renewable generating resources.* Synapse Energy Economics for the Civil Society Institute, April 2013.

Stanton E., F. Ackerman, T. Comings, P. Knight, T. Vitolo, E. Hausman, *Will LNG Exports Benefit the United States Economy?* Synapse Energy Economics for the Sierra Club, January 2013

Ackerman F., T. Vitolo, E. Stanton, G. Keith, *Not-so-smart ALEC: Inside the attacks on renewable energy,* Synapse Energy Economics, January 2013

Woolf T., M. Whited., T. Vitolo, K. Takahashi, D. White, *Indian Point Replacement Analysis: A Clean Energy Roadmap. A Proposal for Replacing the Nuclear Plant with Clean, Sustainable Energy Resource*. Synapse Energy Economics for the National Resources Defense Council and Riverkeeper, October 2012.

Biewald B., T. Vitolo, P. Luckow, *Comments Regarding KCP&L's 2012 IRP Filing*. Sierra Club, Synapse Energy Economics, September 2012.

Hornby R., D. White, T. Vitolo, T. Comings, K. Takahashi, *Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky*. Synapse Energy Economics for Mountain Association for Community Economic Development, and The Kentucky Sustainable Energy Alliance, January 2012.

Keith G., B. Biewald, E. Hausman., K. Takahashi, T. Vitolo, T. Comings, P. Knight, *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011*. Synapse Energy Economics for the Civil Society Institute, November 2011.

Vitolo T., J. Hu., L. Servi, V. Mehta, *Topology Formulation Algorithms for Wireless Networks with Reconfigurable Directional Links*. Proceedings of the IEEE Military Communications Conference, October 2005.

PRESENTATIONS AND POSTER SESSIONS

T. J. Vitolo, "How Big an Issue is Intermittency? Integrating Renewables into a Reliable, Low-Carbon Energy Grid," Civil Society Institute webinar presentation, April 17, 2013.

T.J. Vitolo, "RPS in the USA: The Present Impact and Future Possibilities of Renewable Portfolio Standards in America," Boston University Energy Club Seminar Series, 2009.

T.J. Vitolo, "An ILP Approach to Spanning Tree Problems on Incomplete Graphs with Heterogeneous Degree Constraints," INFORMS Annual Meeting, 2007.

T.J. Vitolo, "Topology Design and Traffic Routing for Wireless Networks with Node-Based Topological Constraints," Boston University CISE Seminar Series, 2004.

OTHER INFORMATION

Fellowships and Scholarships: National Science Foundation IGERT Fellowship, 2006-2008; National Science Foundation GK-12 Fellowship, 2002-2003; Mitchell Scholarship, 2000-2001; Park Scholarship, 1996-2000.

Affiliations: Center for Computation Science, Boston University, 2006-2010; Center for Information and Systems Engineering, Boston University, 2002-2010.

Computer Applications and Programming: Microsoft Office, LATEX, Fortran, C, C++, perl, MATLAB, CPLEX

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Associate, May 2012 – present.
Provides consulting services, conducts research, and performs analysis of energy investments. Calibrates, runs, and modifies industry-standard economic models to evaluate long-term energy plans, and the environmental and economic impacts of policy/regulatory initiatives.

Joint Global Change Research Institute, College Park, MD. Scientist, 2009 – 2011.
Evaluated the long-term implications of potential climate policies, both internationally and in the US, across a range of energy and electricity models. Modeled large-scale biomass use in the global energy system. Led a team studying global wind energy resources and their interaction in the Institute's integrated assessment model. Utilized updated global wind supply curves to help understand both onshore and offshore wind deployment, and issues associated with transmission requirements, intermittency, and technology costs.

DaimlerChrysler, Auburn Hills, MI. Stress Lab & Durability Development Intern, 2007.
Completed load and vibration data acquisition and analysis on various Chrysler vehicles, and contributed to the development of an improved generic body vibration profile.

Northrop Grumman, Rolling Meadows, IL. Defensive Systems Division Co-op, 2005 – 2007.
Designed new enclosures and mounting structures for electronic components, silenced existing enclosures, and conducted thermal testing of complete systems.

EDUCATION

University of Maryland, College Park, MD, MS Mechanical Engineering, 2009.

Northwestern University, Evanston, IL, BS Mechanical Engineering, 2007.

PUBLICATIONS

Luckow P., E. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman, *2013 Carbon Dioxide Price Forecast*. Synapse Energy Economics, November 2013.

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Dooley J., P. Luckow, M.A. Wise, *Algal Biodiesel Production in GCAM: Initial Parameterization and Discussion of Potential Model Development Areas*. Joint Global Change Research Institute, Pacific Northwest National Laboratory, College Park, MD, 2012.

Edmonds J., P. Luckow, K. Calvin, M.A. Wise, J.J. Dooley, P. Kyle, S. Kim, P. Patel, and L.E. Clarke, *Can radiative forcing be limited to 2.6 Wm−2 without negative emissions from bioenergy AND CO2 capture and storage?* Climatic Change, January 2013. DOI: 10.1007/s10584-012-0678-z

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Luckow P., A. Bar-Cohen, and P. Rodgers, and J. Cevallos, *Energy Efficient Polymers for Gas-Liquid Heat Exchangers,* Journal of Energy Resources Technology, Volume 132, Issue 2, June 2010, DOI:10.1115/1.4001568

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