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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

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2 The IPEC, which is located in Buchanan New York, consists of two base-load nuclear generating units that are currently owned by Entergy Nuclear Indian Point 2, LLC, and Entergy Nuclear Indian Point 3, LLC (collectively, Entergy). The Nuclear Regulatory Commission's licenses for IPEC Unit 2 and Unit 3 expire on September 28, 2013, and December 12, 2015, respectively.

3 November 2012 Order, p. 3.

4 On January 14, 2013, and prior to submitting their plan, a meeting was held by Con Edison and NYPA to provide their preliminary concepts for a reliability contingency plan, and to obtain input from interested stakeholders.

from EE and DR programs, and any projects accepted through the RFP process, were proposed as a portfolio to address a potential reliability need of approximately 1,450 MW that could arise in the 2016 summer period. Specifically, a June 1, 2016 reliability need date, when peak summer conditions could be expected to arise, was identified as an in-service date for projects that was consistent with the analysis performed as part of the 2012 Reliability Needs Assessment (RNA) conducted by the New York Independent System Operator, Inc (NYISO).[5]

The Con Edison/NYPA February Filing requested specific actions by the Commission, including: 1) an order in March 2013 requesting NYPA to issue an RFP for solutions to the potential energy reliability needs;[6] 2) an order in April 2013 authorizing the development of the 100 MW of EE and DR programs, the initial planning of the three TOTS projects, and the recovery of prudently incurred costs associated with planning the TOTS projects; and, 3) an order in September 2013 identifying a preferred set of transmission and/or generation projects for inclusion in the IPEC Reliability Contingency Plan, and making findings in connection with an authorization of cost allocation and cost recovery for such projects.[7]

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5 The development of the June 2016 reliability need date, and of the extent of the potential need on that date, is discussed in more detail <u>infra</u>.

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 (<u>i.e.</u>, 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]

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[12] The three TOTS are discussed in detail in Exhibits B, C, and D of the Con Edison/NYPA February Filing, and the update filed on May 20, 2013.

[13] Generation that is "bottled" is physically interconnected, but cannot provide its full output to the grid due to transmission limitations.

The Con Edison/NYPA February Filing sought full recovery of the costs, including any associated contractual cancellation costs, incurred by Con Edison and NYPA for these projects. Con Edison and NYPA provided estimates of the costs to halt the TOTS projects at selected intervals and of the costs to complete each of these projects. The total cost to complete these projects was initially estimated at approximately $511 million. Based on updates filed on May 20, 2013, the cost of the Staten Island project was revised downward, making the total estimated cost of the three TOTS projects approximately $447 million. According to the Con Edison/NYPA February Filing, the TOTS projects would ultimately be transferred to and owned by an entity identified as the "New York Transmission Company" (NY Transco).

Con Edison, together with the other New York investor-owned transmission companies, and NYPA and the Long Island Power Authority (LIPA) (collectively the New York Transmission Owners or NYTOs), are active participants in the process of creating the NY Transco. The NY Transco's purpose and structure are intended to address and overcome planning and cost allocation issues which have, to date, impeded the development of economic transmission projects. The NY Transco would be a new entity formed for the express purpose of developing transmission projects in the State. However, while the NY Transco has not yet been formed, on May 30, 2012, and in response to the New York State Energy Highway Request for Information, the NYTOs identified eighteen transmission projects throughout the State that the NY Transco could develop.[14] The identified projects included the three TOTS projects under consideration here.

B. EE/DR/CHP Programs

The second component of the IPEC Reliability Contingency Plan, as initially presented by Con Edison and NYPA, included a targeted program to achieve 100 MW of permanent peak demand reduction by the summer of 2016. NYPA also identified 15 MW of on-going CHP projects that would be placed in-service by the summer of 2016.

The EE and DR components of the Con Edison/NYPA February Filing were subsequently supplanted with the 125 MW Revised EE/DR/CHP Program proposed by Con Edison and NYSERDA, in consultation with NYPA. The 125 MW Revised EE/DR/CHP Program, filed on June 20, 2013, seeks approval for 100 MW of peak EE/DR and fuel switching projects, which would be coordinated by Con Edison and NYSERDA, along with a 25 MW expanded CHP program that would be administered by NYSERDA.

The EE and DR components of the 125 MW Revised EE/DR/CHP Program would be located within Con Edison's service territory, and are broken down into 44 MW for load management, 40 MW for permanent demand reduction, and 16 MW for fuel switching, for a total of 100 MW. These projects are estimated to cost $219 million, and these costs are proposed to be

[14] See, http://www.nyenergyhighway.com/RFIDocument/transmission/index-2.html. The 18 projects identified by NY Transco could result in an estimated total investment of $2.9 billion in upgrades across the New York State transmission system. Neither the creation of, nor the formation of, nor any specific property transfer to the NY Transco is under review in this Order.

recovered through a surcharge on Con Edison's delivery customers.[15]

The Revised EE and DR components would be jointly implemented by Con Edison and NYSERDA, and are expected to result in a "single point of entry for all participants," with a single application process. These programs would focus on large customers located within Con Edison's service territory. Targeted customers would include: (1) customers with high peak demand; (2) project developers with potential large scale projects; (3) prior or existing Energy Efficiency Portfolio Standard participants that may be willing to expand the scope and depth of projects; and (4) customers capable of switching electric summer air conditioning load to steam or gas.

The Revised EE/DR/CHP Program also included a NYSERDA proposal for an Expanded NYSERDA CHP component for the Program. This aspect of the Program is designed to achieve 25 MW of load reduction. The total cost to ratepayers of the 25 MW Expanded NYSERDA CHP Program is expected to be $66 million, which is broken down to include: 1) $40 million for customer incentives; 2) $16 million for Outreach Assistance Contractor activities; and, 3) $10 million for administrative functions such as NYSERDA staff salaries and State Cost Recovery Fee and Program Evaluation tasks. The total cost for the 125 MW of projects proposed for acceptance in the 125 MW Revised EE/DR/CHP Program would be approximately $285 million.

As part of the filing that included the 125 MW Revised EE/DR/CHP Program, NYSERDA indicated that the 25 MW of proposed CHP projects was in addition to the CHP projects that the

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[15] The surcharge would exclude NYPA's governmental customers who receive delivery service under Con Edison's PSC NO. 12 - Electricity, since they already participate in the NYPA Build Smart NY Program.

Commission previously approved.[16] DPS Staff verified with NYSERDA that 30 MW of these previously approved CHP projects would be operational in Con Edison's service territory by June 2016, and that they were not included in the NYISO's 2012 RNA. In addition, NYPA identified an additional 15 MW that would be achieved under NYPA's Build Smart NY program, which were not identified in the NYISO's 2012 RNA but would be in-service by the summer of 2016. These MW reductions would come from a mix of efficiency gains at state agencies and authorities, wastewater treatment plants in New York City, and campus-wide American Society of Heating, Refrigerating and Air Conditioning Engineers-Level II audits. All NYPA Energy Efficiency Program projects are funded through NYPA low-cost financing that is recovered directly from program participants. As such, the cost of implementing these projects would not be funded through utility tariff charges.

Taken together, all of these projects, including the 15 MW of ongoing CHP projects NYPA identified in the Con Edison/NYPA February filing, would contribute toward meeting the calculated reliability deficiency needs.[17] Cumulatively, the 125 MW of projects proposed in the Revised EE/DR/CHP Program, and

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[16] The Commission's previous approval was in Case 07-M-0548, Energy Efficiency Portfolio Standard - System Benefit Charge IV, Order Modifying Budgets and Targets for Energy Efficiency Portfolio Standard Programs and Providing Funding for Combined Heat and Power and Workforce Development Initiatives (issued December 17, 2012).

[17] As noted above, NYSERDA and NYPA have identified other programs which have already been approved and are funded, but the results of which have not been counted in the NYISO RNA. These programs should contribute approximately 60 MW towards the reliability goal associated with the IPEC Reliability Contingency Plan. See note 11, supra.

the 60 MW from on-going projects[18], would contribute 185 MW toward the potential reliability deficiency need.

On July 17, 2013, a notice was published in the State Register, inviting comments on the Revised EE/DR/CHP Program. Various comments were received by the deadline of September 3, 2013.

DPS Staff Cost Allocation/Cost Recovery Proposal

In response to the April 2013 Order, DPS Staff filed the June Straw Proposal, which described a methodology as to how the costs associated with implementing the transmission or generation solutions that are ultimately part of the IPEC Reliability Contingency Plan could be allocated and recovered from retail ratepayers. At the same time, DPS Staff also provided and sought comments on a draft Reimbursement Agreement prepared by NYPA, which NYPA described as "a necessary component of the mechanism that will be needed to ensure full recovery of costs incurred in connection with the [TOTS] and with generation project(s), if any, selected pursuant to the April 3, 2012 [RFP]."

DPS Staff's June Straw Proposal sought to allocate costs by applying a "beneficiaries pay" principle, whereby the ratepayers that receive the reliability benefits from the IPEC Reliability Contingency Plan would be assigned a proportionate cost recovery responsibility. The June Straw Proposal also attempted to maintain consistency, to the extent practicable, with the NYISO's tariff provisions for allocating the costs of a transmission solution selected to fulfill a need identified in a NYISO Reliability Needs Assessment.

Pursuant to the Notice of Second Technical Conference and Revised Comment Schedule, issued on July 2, 2013, initial comments were sought by July 22, 2013, and reply comments were

[18] See, supra at note 11.

sought by August 5, 2013. Several comments were received in response to this notice.

DISCUSSION

Statutory Authority

With this Order, the Commission accepts a Reliability Contingency Plan that identifies a portfolio of specific transmission and EE/DR/CHP projects that, when taken together, will significantly reduce New Yorker's vulnerability to the costs and disruptions that could occur upon the retirement of IPEC Unit 3 in December 2015. In addition, the Order establishes the methods and mechanisms for the allocation and recovery of the costs and benefits associated with the implementation of the IPEC Reliability Contingency Plan.

Comments have been received in this proceeding in response to several notices seeking comments. These notices are summarized, along with the comments, in Appendix A to this Order. Some commenters expressed concern that the DPS Staff's June Straw Proposal for allocating costs would intrude into Federal Energy Regulatory Commission (FERC)-regulated markets, and would interfere with NYISO operating and planning processes, as well as unnecessarily duplicate, preempt, or nullify portions of the NYISO tariff. Other commenters argued that FERC, and not the Commission, has jurisdiction over cost allocation. These commenters further argued that the Commission lacks authority under the Public Service Law (PSL) for establishing a cost allocation methodology, and that our jurisdiction has not been established on this issue. It is also noted that this Commission lacks jurisdiction over NYPA; that NYPA lacks the authority assumed in the June Straw Proposal; that the Commission has limited jurisdiction over LIPA; and finally, that FERC has exclusive jurisdiction over the proposed TOTS projects.

However, others claim that cost allocation has been delegated to the Commission under the NYISO's compliance filing pertaining to FERC's Order 1000.

Contrary to some parties' arguments, the Commission's authority to adopt and provide for the implementation of this IPEC Reliability Contingency Plan is well founded in the PSL. In particular, section 5(2) of the PSL provides the Commission with authority to "encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."[19] Moreover, section 66(5) of the PSL provides the Commission with authority to address reliability concerns by prescribing the "safe, efficient and adequate property, equipment and appliances thereafter to be used," whenever the NYPSC determines that the utility's existing equipment is "unsafe, inefficient or inadequate."[20] The Commission also has authority to "order reasonable improvements and extensions of the works, wires, poles, lines, conduits,

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[19] Section 5(2) of the PSL has been held to confer "broad discretion" to promote energy conservation. See, Multiple Intervenors v. NYPSC, 166 A.D.2d 140 (3rd Dept. 1991). Furthermore, PSL §5(2) was determined to provide the Commission with jurisdiction to require utilities to file plans outlining how they would adapt to a competitive electric industry. See, Energy Association of New York State v. NYPSC, 169 Misc. 2d 924 (Supreme Ct. 1996)(noting that PSL §5(2) transformed "the traditional role of the Commission from that of an instrument for a simple case-by-case consideration of rates requested by utilities to one charged with the duty of long-range planning for the public benefit").

[20] PSL §66(5). "Electric corporations" are required to provide "such service, instrumentalities and facilities as shall be safe and adequate." PSL §66(1).

ducts and other reasonable devices, apparatus and property of...electric corporations and municipalities."[21] Other provisions of the PSL also provide the Commission with authority over reliability.[22]

Moreover, the Commission's authority to protect or enhance reliability, as it exercises here by accepting the IPEC Reliability Contingency Plan, is expressly preserved under the Federal Power Act. As stated therein, FERC's authority to establish reliability standards "shall [not] be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any [FERC-approved] reliability standard, except that the State of New York may establish rules that result in greater reliability within that State, as long as such action does not result in lesser reliability outside the State than that provided by the [FERC-approved] reliability standards."[23] We find that the IPEC Reliability Contingency Plan usefully defines measures needed to ensure safety, adequacy, and reliability, and may result in greater reliability in New York than would otherwise exist under the FERC-approved reliability standards. Accordingly, our

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[21] PSL §66(2). The NYPSC has continuing jurisdiction over the "construction, operation and maintenance of all utility transmission lines." See, Matter of Stannard v. Axelrod, 100 Misc.2d 702 (Sup. Ct. Broome Co. 1979) (dismissing petition challenging the NYPSC's Order approving a 345 kilovolt transmission line).

[22] See, PSL §§25(4) and 25-a(5) (allowing the NYPSC to impose penalties upon a public utility that fails to comply with regulations related to reliability); see also, PSL §126(1)(d) (providing that before the NYPSC may site a major electric utility transmission facility, the Commission must find that such facility "will serve the interests of electric system economy and reliability").

[23] 16 U.S.C. §824o(i)(3).

authority to accept the IPEC Reliability Contingency Plan is not preempted by FERC or the NYISO planning process.

In addition, the Commission has authority to ensure that "[a]ll charges made or demanded by any...electric corporation or municipality for…electricity or any service rendered or to be rendered, shall be just and reasonable and not more than allowed by law or by order of the commission."[24] As the April 2013 Order stated, the Commission possesses the "authority to develop a retail rate recovery mechanism that provides for the jurisdictional utilities to collect payments from their ratepayers for reliability-related activities."[25] The Commission also concluded that "this funding may be used to support actions taken by NYPA in support of their reliability-related activities undertaken in conjunction with the Indian Point Contingency Plan."[26] The Commission further noted that it was not "asserting jurisdiction over NYPA, the rates NYPA charges its customers, or wholesale transmission rates established by FERC." We conclude that these findings continue to adhere to the rulings in this Order.

With respect to cost allocation and recovery for the TOTS projects, however, we do not need to exercise our legal authority to decide the cost allocation and recovery issues. We understand from the NYTO's comments that the TOTS project developers, together with the other NYTOs which are proposed members of the NY Transco, intend to seek cost recovery for the TOTS through FERC-approved tariffs. The TOTS developers have also indicated that they intend to propose a cost allocation methodology to FERC that is consistent with the methodology developed by the NYTOs in connection with the NY Transco

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[24] PSL §65(1).

[25] April 2013 Order, p. 10.

[26] Id.

concept. We concur with the NYTOs that cost recovery and allocation through a FERC tariff are appropriate for these projects, and we intend to support such an application regarding the TOTS projects in so far as the application's proposed revenue requirement reflects the cost estimates and cost allocation methodology set forth in the NYTOs' filings in this proceeding. We urge the NYTOs to proceed as quickly as possible at FERC. In connection with that application, we will direct Con Edison, in consultation with NYPA, to supply a report on the progress of this application on or before June 30, 2014, and every six months thereafter.

Identification of Reliability Needs

The reliability implications of retiring IPEC have been well documented by the NYISO. While the NYISO assumed that IPEC was available in the 2012 RNA base case, it performed a further analysis with IPEC unavailable. This analysis found that "reliability violations would occur in 2016 if the Indian Point Plant were to be retired by the end of 2015."[27] The NYISO's 2012 RNA transmission security analysis indicated that, without Indian Point, already constrained transfer limits into Southeastern New York would be further aggravated.[28] In order to mitigate these overloads, the NYISO stated that compensatory megawatts would be needed in Zones G, H, I, J, or the western

[27] New York Independent System Operator 2012 Reliability Needs Assessment, Final Report, dated September 18, 2012, p. 42.

[28] Specifically, a transmission security analysis indicated overloaded conditions on the Leeds-Pleasant Valley and Athens-Pleasant Valley 345 kV lines, the Fraser-Coopers Corners and Rock Tavern-Ramapo 345 kV lines, and the Roseton-East Fishkill 345 kV line.

portion of Zone K,[29] amounting to 1,000 MW in 2016, noting that the amount of compensatory megawatts could increase depending on the location of the resource.[30]

Finally, the NYISO's 2012 RNA Indian Point Plant Retirement Scenario showed significant Loss of Load Expectation (LOLE)/resource adequacy violations if Indian Point were not available. Using the base case load forecast, the 2016 LOLE would be 0.48 days per year. This represented a significant violation of the 0.1 days per year criterion.[31]

The Con Edison/NYPA February Filing stated that it relied on the NYISO's 2012 RNA base case as the starting point for its analysis, noting that it is the NYISO's most recent evaluation of the bulk power system over the next ten years.[32] According to the filing, the base case was then updated by adjusting for known additions and retirements since the NYISO analysis was performed. Specifically, the NYISO's 2012 RNA base case was adjusted by adding 320 MW associated with the rescission of a mothball notice by Astoria Generating Company, L.P.'s Gowanus barges 1 and 4, and reducing the reliability deficiency need amount to reflect the effect of the 100 MW EE/DR

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[29] The location of these Zones in New York State can be understood from a map at the NYISO website. See, http://www.nyiso.com/public/markets_operations/market_data/maps/index.jsp.

[30] New York Independent System Operator 2012 Reliability Needs Assessment, Final Report, dated September 18, 2012, p. 43.

[31] The New York State bulk power system is planned to meet a LOLE that, at any given point in time, is less than or equal to a involuntary load disconnection that is not more frequent than 0.1 days per year. In other words, the bulk power system is planned so that there is sufficient transmission and generation such that the LOLE is no more than once every 10 years.

[32] Con Edison notes that the RNA model and assumptions were a result of extensive stakeholder review.

peak load reduction program proposed in the Con Edison/NYPA February Filing. The results of the analysis, as indicated in the Con Edison/NYPA February Filing, showed a deficiency of 950 MW, as compared to the NYISO 2012 RNA analysis, which showed a deficiency of approximately 1,000 MW.

As Con Edison's analysis was nearing completion, however, the retirement of the Danskammer generating facility was announced. Based on this announcement in January 2013, the effect of this retirement was estimated by Con Edison to increase the reliability needs by an additional 400-425 MW, making the total deficiency approximately 1,450 MW (or approximately 1,350 MW accounting for the effect of the initial proposed 100 MW EE/DR program).

In order to conduct an independent analysis and update of the reliability deficiency needs and to perform other work which would be useful for Staff's Contingency Plan analysis, as directed in the March 2013 Order, DPS Staff obtained the consulting services of Brattle. Thereafter, DPS Staff directed Brattle to analyze the reliability needs that would attend the retirement of the IPEC at the end of 2015. DPS Staff indicated that the updated base case in the analysis should model NRG Energy, Inc's Astoria Gas Turbine Units 10 and 11, which are expected to return to service.[33] Based on the analysis, DPS Staff confirmed the validity of the reliability needs identified in the Con Edison/NYPA February Filing, and that if IPEC Units 2 and 3 were to retire upon the expiration of its current licenses in 2013 and 2015, respectively, Southeast New York would not have enough capacity to avoid reliability violations in the summer of 2016.

[33] On June 7, 2013, NRG Energy, Inc. filed, in Case 05-E-0889, a notice of intent to return Astoria Gas Turbine Units 10 and 11 to service.

Contrary to parties' claims, we find that the various analyses performed of the potential reliability impacts associated with the retirement of IPEC provide a sufficient record and a rational basis to identify a reliability deficiency need of approximately 1,450 MW. We reject, however, parties' suggestions that the Commission should rely on the NYISO planning process to resolve these potential reliability needs, or that we should not plan for the contingency that IPEC may be retired.[34] As observed in the March 2013 Order, the NYISO's process currently assumes that IPEC will remain available, and therefore, it is not conducting the reliability contingency planning that we are conducting now.[35] We disagree that a reasonable planning approach under the circumstances should rely solely on market-based projects to appear, or that we should wait for the NYISO to "trigger" the need for the implementation of a reliability solution. In the event IPEC were unable to obtain the necessary consents and approvals to continue operating, or if Entergy could decide that continued operation of IPEC is not in its interest,[36] there would unlikely be sufficient time to address the resulting reliability needs.

The requirement that the projects included in the IPEC Reliability Contingency Plan meet a firm in-service deadline of June 1, 2016 comports with the NYISO's identified reliability

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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 <u>net</u> 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 <u>net</u> benefits was estimated to be approximately $670 million.[41] DPS Staff indicates that if IPEC were retired, the estimated <u>net</u> 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

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[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

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[42] The test was set forth using the following formula:

$$\frac{\text{Benefit}}{\text{Cost}} = \frac{\text{NPV(Energy + LineLoss + Capacity + Environmental + T + D)}}{\text{NPV(UtilityCosts + CustomerCosts + ProgramAdmin)}}$$

We note that the "customer costs" in the above formula are not paid by utility ratepayer funds, but rather by customers' own funds.

million over 15 years.[43] The estimated net resource cost savings were greater assuming IPEC is retired.

DPS Staff therefore recommends that these EE and DR programs be included in the IPEC Reliability Contingency Plan. We agree with DPS Staff that these EE and DR programs are worthwhile pursuing, given our expectation that the benefits of these projects will exceed the costs. Accordingly, we accept the EE and DR components (totaling 100 MW) of the 125 MW Revised EE/DR/CHP Program, as proposed by Con Edison and NYSERDA.

We disagree with parties that suggest the proposed EE and DR resources should be compared to the cost of the transmission and generation resources that were submitted for consideration as replacement resources for IPEC. Based on the cost effectiveness of the proposed EE and DR programs, such a comparison is unnecessary. These programs are reasonable to pursue, regardless of whether IPEC is retired.

An important consideration for some parties is the extent to which the EE and DR program's peak demand reduction efforts would be coordinated with NYSERDA and Con Edison's regular EE programs. We are persuaded that the programs will be appropriately coordinated. Moreover, the proposal has the characteristic that the incentives and program rules of the commercial and industrial programs will be uniform for both the Commission's Energy Efficiency Portfolio Standard (EEPS) kWh incentives and the incentives for the EE and DR programs which we are considering here. Other elements of these EE and DR programs, such as thermal energy storage and battery arrays, are new programs that will not affect existing EEPS programs.

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[43] The benefits of the EE and DR programs identified in the Revised EE/DR/CHP Program exceeded the costs, even with the environmental components removed. Thus, the $182 million estimate would be even higher if the environmental components were included.

Entergy asserts that reliance on EE is a major deviation from reliability system planning that could threaten system reliability if the energy efficiency program does not achieve its projected gains. We agree that reliance on EE and DR programs is relatively new. Energy efficiency, however, is not so new as to be untested. New York and several other states have accumulated significant experience with EE over the last 20 years. In fact, EE results are routinely used in the NYISO planning process as load modifiers. We are confident that EE is a proven resource that can be relied upon for many purposes, including the one at hand - ensuring reliability in the event IPEC is retired.

Many other details have been suggested by commenters, including combining EE with renewable generation at a customer location, aggregation of small thermal storage projects, and providing extra incentives for "Made in New York" solutions. Our primary goal here, however, is to obtain the peak MW reductions needed by 2016 to help protect against reliability violations which could stem from the retirement of the IPEC. We will therefore accept the proposal, as put forward by Con Edison, NYSERDA, and NYPA, without further imposing specific requirements such as these.

We recognize that the EE and DR programs would be jointly implemented by Con Edison and NYSERDA, and we seek to ensure appropriate coordination between the two entities. The proposal to maintain a "single point of customer entry" should assist in eliminating duplicative procedures and confusion for customers. We anticipate that Con Edison and NYSERDA will develop appropriate agreements to facilitate the provision of any necessary customer information and program funds from Con

Edison to NYSERDA.[44] To the extent such agreements cannot be reached after consultation with DPS Staff, a petition should be filed with the Commission for resolution.

We also find that NYSERDA's Expanded CHP Program should be pursued to obtain 25 MW, which is in addition to the 30 MW that NYSERDA estimates will be achieved in Con Edison's service territory by June 2016 under the CHP Program already approved by the Commission. We recognize that promoting CHP resources has broad and deep support among environmental, governmental, and business interests. We find that committing further funding toward CHP projects will help to advance the Commission's objective of promoting CHP, and to reduce the reliability needs identified in the NYISO's September 18, 2012 RNA. We also concur with the parties that believe that DR and CHP should, in combination, form a substantial component of the resources that are developed as part of the response to the potential retirement of IPEC. To ensure proper accounting and reporting of the CHP aspects of the Revised EE/DR/CHP Program, Con Edison and NYSERDA should develop detailed accounting procedures, reporting requirements and an implementation plan, as we are requiring with respect to the EE and DR programs.

Finally, we acknowledge NYPA's Build Smart NY Program, and will count NYPA's 15 MW target toward the identified reliability needs under the IPEC Reliability Contingency Plan. However, because this program will be funded through NYPA low cost financing that is recovered from the direct program participants, we do not need to approve the program or the

[44] Con Edison shall establish by agreement with NYSERDA, procedures for the transfer of funds to NYSERDA to repay NYSERDA for the costs it incurs in implementing the portion of the Revised EE/DR/CHP Program for which NYSERAD has responsibility. The form of this agreement, and of any amendments to this agreement, shall be filed with the Secretary as a compliance filing.

associated funding. We expect that NYPA will update the Commission in the event that changed circumstances affect the achievement of the target amount within the necessary time frame.

In this Order, we accept the 125 MW EE/DR/CHP program set forth by Con Edison, NYSERDA and NYPA, and we take account of approximately 60 MW of peak demand reduction which these parties expect to achieve from existing programs. We recognize these are modest goals for programs of this type. We believe there continues to be unrecognized, cost-effective opportunities for EE, DR, and CHP programs to meet a greater portion of the reliability needs which the IPEC Reliability Contingency Plan describes. We direct Con Edison, working with DPS Staff, NYPA, and NYSERDA, to intensify its efforts to identify and exploit these additional opportunities, and direct Con Edison to report on these efforts by February 15, 2014.

Cost Allocation

As noted above, DPS Staff, at our direction, prepared and filed a proposed methodology for allocating and recovering costs associated with the IPEC Reliability Contingency Plan, which was the subject of two technical conferences and various comments. In general, the DPS Staff's June Straw Proposal recommended that the same cost allocation methodology should be used for each element of the IPEC Reliability Contingency Plan portfolio. In this Order, and as discussed below, we are sensitive to the particular characteristics of the various elements of the portfolio, and we do not conclude that the same cost allocation methodologies should be used for all portfolio elements. Instead, we prefer to tailor the cost allocation solutions in a more granular way so that each specific portfolio element uses the methodology that best suits its particular characteristics.

A. TOTS Projects

In conjunction with their proposal for the TOTS projects, Con Edison and NYPA, along with the other NYTOs, have urged that DPS Staff's June Straw Proposal methodology should not be used to allocate the costs associated with implementing those projects. Instead, Con Edison and NYPA urge that the TOTS costs should be allocated in proportion to the shares already agreed to by the NYTOs in the context of preparing their NY Transco proposal.[45] As noted above, Con Edison, NYPA and the other NY Transco participants have jointly identified 18 transmission projects throughout the State which, if approved, could be undertaken to improve the State's transmission system. The three TOTS projects were among those identified by the proponents of the NY Transco.

In response to the NYTOs' cost allocation proposal, various commenters argued that cost allocation should be based solely upon a reliability beneficiaries pay methodology and should be consistent with the NYISO approach for reliability solutions. Some commenters were specifically critical of the NY Transco approach based upon their belief that the benefits of the three TOTS projects will accrue to Southeastern New York alone, and, at the same time, will bring higher energy costs and emissions to Upstate New York. Commenters also argued that the derivation of the NY Transco method has not been explained, and

[45] The NYTOs have agreed to a NY Transco cost allocation as follows: 5.4% for Central Hudson Gas & Electric Corp. (CHG&E), 38.3% for Con Edison, 16.7% for Long Island Power Authority (LIPA), 10.4% for Niagara Mohawk d.b.a. Nation Grid, 5.8% for New York State Electric & Gas (NYSEG), 3.4% for Orange & Rockland Utilities (O&R), 16.9% for NYPA, and 3.1% for Rochester Gas & Electric Corp. (RG&E). See, NYTO comments, dated July 22, 2013.

that its sponsors have not demonstrated that the method aligns allocated costs with benefits. Further, concerns were raised that the NY Transco method will lead to inconsistencies between TOTS solutions and non-TOTS solutions, thereby resulting in an unlevel playing field and divergence from the NYISO reliability cost allocation approach. Others contended that the NY Transco cost allocation method was previously rejected by the Commission in the April 2013 Order. Finally, some commenters urged that the public policy that is needed to define and sanction the benefits claimed for the TOTS projects has not been developed and that this proceeding was not intended as the forum in which this policy should be developed.

While we understand the commenters' concerns regarding the potential for different cost allocation methods for different solutions, we recognize several factors which weigh in favor of utilizing the proposed NY Transco approach for the three TOTS projects. Specifically, the NY Transco allocation was voluntarily developed and approved by all of the NYTOs. We acknowledge that the NYTOs have achieved a significant milestone in reaching this consensus, as they have solved a problem that can hinder the construction of infrastructure across utility service territories. In this instance, however, that barrier has been surmounted. In addition, based upon the IPEC Reliability Contingency Plan analysis, the three proposed TOTS projects were found to provide net benefits both with and without IPEC in service. We also recognize that the benefits from resource adequacy solutions for the replacement of the IPEC, such as the TOTS, do not accrue solely to downstate consumers. Rather, we agree with the NYTOs that these solutions should also provide some reliability benefits statewide. Based on these factors, we find the proposed allocation of costs and benefits to be reasonable, and support the use of the proposed NY Transco cost allocation methodology.

Finally, we note that the proposed NY Transco approach, which provides that a share of the project costs will be assumed by LIPA and NYPA, achieves a broader distribution of project costs than have been achieveable in the past. In this regard, it is significant that LIPA has already indicated its agreement with the NY Transco approach.[46] For this reason, it appears unlikely that a jurisdictional challenge from LIPA will be made.

B. EE/DR/CHP Programs

DPS Staff's June Straw Proposal was silent on cost allocation for EE, DR, and CHP projects. However, the EE/DR/CHP submissions by Con Edison and NYPA urge that the costs of these programs should be allocated to Con Edison's ratepayers, just as the costs of similar utility EE, DR, or CHP programs have been allocated in the past. No commenters raised specific opposition to Con Edison's proposal. While some commenters favored a single cost allocation approach for all solutions, some favored Con Edison's cost allocation proposal for these programs. NYC stated that cost allocation of EE/DR/CHP projects need not be the same as that afforded to generation and transmission projects. Rather, NYC contends that the "benefits associated with EE/DR/CHP projects are so specific to the utility service territory in which they are located that costs associated with those measures should not be spread to other utilities."[47]

Con Edison will have the ability to target its EE/DR program to help relieve its local distribution system, thereby

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[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."

<u>Cost Recovery</u>

A. <u>TOTS Projects</u>

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. <u>EE/DR/CHP Programs</u>

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. April 2013 Order

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

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[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

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[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

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

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2 The IPEC, which is located in Buchanan New York, consists of two base-load nuclear generating units that are currently owned by Entergy Nuclear Indian Point 2, LLC, and Entergy Nuclear Indian Point 3, LLC (collectively, Entergy). The Nuclear Regulatory Commission's licenses for IPEC Unit 2 and Unit 3 expire on September 28, 2013, and December 12, 2015, respectively.

3 November 2012 Order, p. 3.

4 On January 14, 2013, and prior to submitting their plan, a meeting was held by Con Edison and NYPA to provide their preliminary concepts for a reliability contingency plan, and to obtain input from interested stakeholders.

from EE and DR programs, and any projects accepted through the RFP process, were proposed as a portfolio to address a potential reliability need of approximately 1,450 MW that could arise in the 2016 summer period. Specifically, a June 1, 2016 reliability need date, when peak summer conditions could be expected to arise, was identified as an in-service date for projects that was consistent with the analysis performed as part of the 2012 Reliability Needs Assessment (RNA) conducted by the New York Independent System Operator, Inc (NYISO).[5]

The Con Edison/NYPA February Filing requested specific actions by the Commission, including: 1) an order in March 2013 requesting NYPA to issue an RFP for solutions to the potential energy reliability needs;[6] 2) an order in April 2013 authorizing the development of the 100 MW of EE and DR programs, the initial planning of the three TOTS projects, and the recovery of prudently incurred costs associated with planning the TOTS projects; and, 3) an order in September 2013 identifying a preferred set of transmission and/or generation projects for inclusion in the IPEC Reliability Contingency Plan, and making findings in connection with an authorization of cost allocation and cost recovery for such projects.[7]

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5 The development of the June 2016 reliability need date, and of the extent of the potential need on that date, is discussed in more detail infra.

6 The November 2012 Order, and the Notice Soliciting Comments issued on February 13, 2013, sought comments, by February 22, 2013, on the first requested action item (i.e., the issuance of the NYPA RFP, and related matters).

7 The Con Edison/NYPA February Filing sought certain findings by the Commission, including findings that each of the TOTS projects would be a public policy project that meets the public policy requirements of New York State.

On March 15, 2013, the Commission issued an order that responded to the first requested action in the Con Edison/NYPA February Filing.[8] In particular, the March 2013 Order approved the proposal, subject to certain modifications, for NYPA to issue an RFP. The RFP was subsequently issued by NYPA on April 3, 2013, and responses to the RFP were received on or about May 20, 2013.

On April 19, 2013, the Commission responded to the second request in the Con Edison/NYPA February Filing, and approved, subject to conditions, Con Edison, NYSEG, and NYPA's preliminary planning related to the three TOTS projects.[9] While preliminary planning was approved for the TOTS, as described in the Con Edison/NYPA February Filing, the recovery of planning costs was capped at $10 million for an initial period until the TOTS projects were analyzed further.[10] In the April 2013 Order, Con Edison was also directed to work with the New York State Energy Research and Development Authority (NYSERDA) and NYPA, and to file a revised plan to secure permanent peak reduction from incremental EE and DR programs and other resources. Finally, the Order directed DPS Staff to propose a cost

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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]

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[12] The three TOTS are discussed in detail in Exhibits B, C, and D of the Con Edison/NYPA February Filing, and the update filed on May 20, 2013.

[13] Generation that is "bottled" is physically interconnected, but cannot provide its full output to the grid due to transmission limitations.

The Con Edison/NYPA February Filing sought full recovery of the costs, including any associated contractual cancellation costs, incurred by Con Edison and NYPA for these projects. Con Edison and NYPA provided estimates of the costs to halt the TOTS projects at selected intervals and of the costs to complete each of these projects. The total cost to complete these projects was initially estimated at approximately $511 million. Based on updates filed on May 20, 2013, the cost of the Staten Island project was revised downward, making the total estimated cost of the three TOTS projects approximately $447 million. According to the Con Edison/NYPA February Filing, the TOTS projects would ultimately be transferred to and owned by an entity identified as the "New York Transmission Company" (NY Transco).

Con Edison, together with the other New York investor-owned transmission companies, and NYPA and the Long Island Power Authority (LIPA) (collectively the New York Transmission Owners or NYTOs), are active participants in the process of creating the NY Transco. The NY Transco's purpose and structure are intended to address and overcome planning and cost allocation issues which have, to date, impeded the development of economic transmission projects. The NY Transco would be a new entity formed for the express purpose of developing transmission projects in the State. However, while the NY Transco has not yet been formed, on May 30, 2012, and in response to the New York State Energy Highway Request for Information, the NYTOs identified eighteen transmission projects throughout the State that the NY Transco could develop.[14] The identified projects included the three TOTS projects under consideration here.

B. EE/DR/CHP Programs

The second component of the IPEC Reliability Contingency Plan, as initially presented by Con Edison and NYPA, included a targeted program to achieve 100 MW of permanent peak demand reduction by the summer of 2016. NYPA also identified 15 MW of on-going CHP projects that would be placed in-service by the summer of 2016.

The EE and DR components of the Con Edison/NYPA February Filing were subsequently supplanted with the 125 MW Revised EE/DR/CHP Program proposed by Con Edison and NYSERDA, in consultation with NYPA. The 125 MW Revised EE/DR/CHP Program, filed on June 20, 2013, seeks approval for 100 MW of peak EE/DR and fuel switching projects, which would be coordinated by Con Edison and NYSERDA, along with a 25 MW expanded CHP program that would be administered by NYSERDA.

The EE and DR components of the 125 MW Revised EE/DR/CHP Program would be located within Con Edison's service territory, and are broken down into 44 MW for load management, 40 MW for permanent demand reduction, and 16 MW for fuel switching, for a total of 100 MW. These projects are estimated to cost $219 million, and these costs are proposed to be

[14] See, http://www.nyenergyhighway.com/RFIDocument/transmission/index-2.html. The 18 projects identified by NY Transco could result in an estimated total investment of $2.9 billion in upgrades across the New York State transmission system. Neither the creation of, nor the formation of, nor any specific property transfer to the NY Transco is under review in this Order.

recovered through a surcharge on Con Edison's delivery customers.[15]

The Revised EE and DR components would be jointly implemented by Con Edison and NYSERDA, and are expected to result in a "single point of entry for all participants," with a single application process. These programs would focus on large customers located within Con Edison's service territory. Targeted customers would include: (1) customers with high peak demand; (2) project developers with potential large scale projects; (3) prior or existing Energy Efficiency Portfolio Standard participants that may be willing to expand the scope and depth of projects; and (4) customers capable of switching electric summer air conditioning load to steam or gas.

The Revised EE/DR/CHP Program also included a NYSERDA proposal for an Expanded NYSERDA CHP component for the Program. This aspect of the Program is designed to achieve 25 MW of load reduction. The total cost to ratepayers of the 25 MW Expanded NYSERDA CHP Program is expected to be $66 million, which is broken down to include: 1) $40 million for customer incentives; 2) $16 million for Outreach Assistance Contractor activities; and, 3) $10 million for administrative functions such as NYSERDA staff salaries and State Cost Recovery Fee and Program Evaluation tasks. The total cost for the 125 MW of projects proposed for acceptance in the 125 MW Revised EE/DR/CHP Program would be approximately $285 million.

As part of the filing that included the 125 MW Revised EE/DR/CHP Program, NYSERDA indicated that the 25 MW of proposed CHP projects was in addition to the CHP projects that the

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[15] The surcharge would exclude NYPA's governmental customers who receive delivery service under Con Edison's PSC NO. 12 - Electricity, since they already participate in the NYPA Build Smart NY Program.

Commission previously approved.[16] DPS Staff verified with NYSERDA that 30 MW of these previously approved CHP projects would be operational in Con Edison's service territory by June 2016, and that they were not included in the NYISO's 2012 RNA. In addition, NYPA identified an additional 15 MW that would be achieved under NYPA's Build Smart NY program, which were not identified in the NYISO's 2012 RNA but would be in-service by the summer of 2016. These MW reductions would come from a mix of efficiency gains at state agencies and authorities, wastewater treatment plants in New York City, and campus-wide American Society of Heating, Refrigerating and Air Conditioning Engineers-Level II audits. All NYPA Energy Efficiency Program projects are funded through NYPA low-cost financing that is recovered directly from program participants. As such, the cost of implementing these projects would not be funded through utility tariff charges.

Taken together, all of these projects, including the 15 MW of ongoing CHP projects NYPA identified in the Con Edison/NYPA February filing, would contribute toward meeting the calculated reliability deficiency needs.[17] Cumulatively, the 125 MW of projects proposed in the Revised EE/DR/CHP Program, and

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16 The Commission's previous approval was in Case 07-M-0548, Energy Efficiency Portfolio Standard - System Benefit Charge IV, Order Modifying Budgets and Targets for Energy Efficiency Portfolio Standard Programs and Providing Funding for Combined Heat and Power and Workforce Development Initiatives (issued December 17, 2012).

17 As noted above, NYSERDA and NYPA have identified other programs which have already been approved and are funded, but the results of which have not been counted in the NYISO RNA. These programs should contribute approximately 60 MW towards the reliability goal associated with the IPEC Reliability Contingency Plan. See note 11, supra.

the 60 MW from on-going projects[18], would contribute 185 MW toward the potential reliability deficiency need.

On July 17, 2013, a notice was published in the State Register, inviting comments on the Revised EE/DR/CHP Program. Various comments were received by the deadline of September 3, 2013.

DPS Staff Cost Allocation/Cost Recovery Proposal

In response to the April 2013 Order, DPS Staff filed the June Straw Proposal, which described a methodology as to how the costs associated with implementing the transmission or generation solutions that are ultimately part of the IPEC Reliability Contingency Plan could be allocated and recovered from retail ratepayers. At the same time, DPS Staff also provided and sought comments on a draft Reimbursement Agreement prepared by NYPA, which NYPA described as "a necessary component of the mechanism that will be needed to ensure full recovery of costs incurred in connection with the [TOTS] and with generation project(s), if any, selected pursuant to the April 3, 2012 [RFP]."

DPS Staff's June Straw Proposal sought to allocate costs by applying a "beneficiaries pay" principle, whereby the ratepayers that receive the reliability benefits from the IPEC Reliability Contingency Plan would be assigned a proportionate cost recovery responsibility. The June Straw Proposal also attempted to maintain consistency, to the extent practicable, with the NYISO's tariff provisions for allocating the costs of a transmission solution selected to fulfill a need identified in a NYISO Reliability Needs Assessment.

Pursuant to the Notice of Second Technical Conference and Revised Comment Schedule, issued on July 2, 2013, initial comments were sought by July 22, 2013, and reply comments were

[18] See, supra at note 11.

sought by August 5, 2013. Several comments were received in response to this notice.

DISCUSSION

Statutory Authority

With this Order, the Commission accepts a Reliability Contingency Plan that identifies a portfolio of specific transmission and EE/DR/CHP projects that, when taken together, will significantly reduce New Yorker's vulnerability to the costs and disruptions that could occur upon the retirement of IPEC Unit 3 in December 2015. In addition, the Order establishes the methods and mechanisms for the allocation and recovery of the costs and benefits associated with the implementation of the IPEC Reliability Contingency Plan.

Comments have been received in this proceeding in response to several notices seeking comments. These notices are summarized, along with the comments, in Appendix A to this Order. Some commenters expressed concern that the DPS Staff's June Straw Proposal for allocating costs would intrude into Federal Energy Regulatory Commission (FERC)-regulated markets, and would interfere with NYISO operating and planning processes, as well as unnecessarily duplicate, preempt, or nullify portions of the NYISO tariff. Other commenters argued that FERC, and not the Commission, has jurisdiction over cost allocation. These commenters further argued that the Commission lacks authority under the Public Service Law (PSL) for establishing a cost allocation methodology, and that our jurisdiction has not been established on this issue. It is also noted that this Commission lacks jurisdiction over NYPA; that NYPA lacks the authority assumed in the June Straw Proposal; that the Commission has limited jurisdiction over LIPA; and finally, that FERC has exclusive jurisdiction over the proposed TOTS projects.

However, others claim that cost allocation has been delegated to the Commission under the NYISO's compliance filing pertaining to FERC's Order 1000.

Contrary to some parties' arguments, the Commission's authority to adopt and provide for the implementation of this IPEC Reliability Contingency Plan is well founded in the PSL. In particular, section 5(2) of the PSL provides the Commission with authority to "encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."[19] Moreover, section 66(5) of the PSL provides the Commission with authority to address reliability concerns by prescribing the "safe, efficient and adequate property, equipment and appliances thereafter to be used," whenever the NYPSC determines that the utility's existing equipment is "unsafe, inefficient or inadequate."[20] The Commission also has authority to "order reasonable improvements and extensions of the works, wires, poles, lines, conduits,

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[19] Section 5(2) of the PSL has been held to confer "broad discretion" to promote energy conservation. <u>See</u>, <u>Multiple Intervenors v. NYPSC</u>, 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. <u>See</u>, <u>Energy Association of New York State v. NYPSC</u>, 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

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21 PSL §66(2). The NYPSC has continuing jurisdiction over the "construction, operation and maintenance of all utility transmission lines." See, Matter of Stannard v. Axelrod, 100 Misc.2d 702 (Sup. Ct. Broome Co. 1979) (dismissing petition challenging the NYPSC's Order approving a 345 kilovolt transmission line).

22 See, PSL §§25(4) and 25-a(5) (allowing the NYPSC to impose penalties upon a public utility that fails to comply with regulations related to reliability); see also, PSL §126(1)(d) (providing that before the NYPSC may site a major electric utility transmission facility, the Commission must find that such facility "will serve the interests of electric system economy and reliability").

23 16 U.S.C. §824o(i)(3).

authority to accept the IPEC Reliability Contingency Plan is not preempted by FERC or the NYISO planning process.

In addition, the Commission has authority to ensure that "[a]ll charges made or demanded by any...electric corporation or municipality for...electricity or any service rendered or to be rendered, shall be just and reasonable and not more than allowed by law or by order of the commission."[24] As the April 2013 Order stated, the Commission possesses the "authority to develop a retail rate recovery mechanism that provides for the jurisdictional utilities to collect payments from their ratepayers for reliability-related activities."[25] The Commission also concluded that "this funding may be used to support actions taken by NYPA in support of their reliability-related activities undertaken in conjunction with the Indian Point Contingency Plan."[26] The Commission further noted that it was not "asserting jurisdiction over NYPA, the rates NYPA charges its customers, or wholesale transmission rates established by FERC." We conclude that these findings continue to adhere to the rulings in this Order.

With respect to cost allocation and recovery for the TOTS projects, however, we do not need to exercise our legal authority to decide the cost allocation and recovery issues. We understand from the NYTO's comments that the TOTS project developers, together with the other NYTOs which are proposed members of the NY Transco, intend to seek cost recovery for the TOTS through FERC-approved tariffs. The TOTS developers have also indicated that they intend to propose a cost allocation methodology to FERC that is consistent with the methodology developed by the NYTOs in connection with the NY Transco

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[24] PSL §65(1).

[25] April 2013 Order, p. 10.

[26] Id.

concept. We concur with the NYTOs that cost recovery and allocation through a FERC tariff are appropriate for these projects, and we intend to support such an application regarding the TOTS projects in so far as the application's proposed revenue requirement reflects the cost estimates and cost allocation methodology set forth in the NYTOs' filings in this proceeding. We urge the NYTOs to proceed as quickly as possible at FERC. In connection with that application, we will direct Con Edison, in consultation with NYPA, to supply a report on the progress of this application on or before June 30, 2014, and every six months thereafter.

Identification of Reliability Needs

The reliability implications of retiring IPEC have been well documented by the NYISO. While the NYISO assumed that IPEC was available in the 2012 RNA base case, it performed a further analysis with IPEC unavailable. This analysis found that "reliability violations would occur in 2016 if the Indian Point Plant were to be retired by the end of 2015."[27] The NYISO's 2012 RNA transmission security analysis indicated that, without Indian Point, already constrained transfer limits into Southeastern New York would be further aggravated.[28] In order to mitigate these overloads, the NYISO stated that compensatory megawatts would be needed in Zones G, H, I, J, or the western

[27] New York Independent System Operator 2012 Reliability Needs Assessment, Final Report, dated September 18, 2012, p. 42.

[28] Specifically, a transmission security analysis indicated overloaded conditions on the Leeds-Pleasant Valley and Athens-Pleasant Valley 345 kV lines, the Fraser-Coopers Corners and Rock Tavern-Ramapo 345 kV lines, and the Roseton-East Fishkill 345 kV line.

portion of Zone K,[29] amounting to 1,000 MW in 2016, noting that the amount of compensatory megawatts could increase depending on the location of the resource.[30]

Finally, the NYISO's 2012 RNA Indian Point Plant Retirement Scenario showed significant Loss of Load Expectation (LOLE)/resource adequacy violations if Indian Point were not available. Using the base case load forecast, the 2016 LOLE would be 0.48 days per year. This represented a significant violation of the 0.1 days per year criterion.[31]

The Con Edison/NYPA February Filing stated that it relied on the NYISO's 2012 RNA base case as the starting point for its analysis, noting that it is the NYISO's most recent evaluation of the bulk power system over the next ten years.[32] According to the filing, the base case was then updated by adjusting for known additions and retirements since the NYISO analysis was performed. Specifically, the NYISO's 2012 RNA base case was adjusted by adding 320 MW associated with the rescission of a mothball notice by Astoria Generating Company, L.P.'s Gowanus barges 1 and 4, and reducing the reliability deficiency need amount to reflect the effect of the 100 MW EE/DR

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[29] The location of these Zones in New York State can be understood from a map at the NYISO website. See, http://www.nyiso.com/public/markets_operations/market_data/maps/index.jsp.

[30] New York Independent System Operator 2012 Reliability Needs Assessment, Final Report, dated September 18, 2012, p. 43.

[31] The New York State bulk power system is planned to meet a LOLE that, at any given point in time, is less than or equal to a involuntary load disconnection that is not more frequent than 0.1 days per year. In other words, the bulk power system is planned so that there is sufficient transmission and generation such that the LOLE is no more than once every 10 years.

[32] Con Edison notes that the RNA model and assumptions were a result of extensive stakeholder review.

peak load reduction program proposed in the Con Edison/NYPA February Filing. The results of the analysis, as indicated in the Con Edison/NYPA February Filing, showed a deficiency of 950 MW, as compared to the NYISO 2012 RNA analysis, which showed a deficiency of approximately 1,000 MW.

As Con Edison's analysis was nearing completion, however, the retirement of the Danskammer generating facility was announced. Based on this announcement in January 2013, the effect of this retirement was estimated by Con Edison to increase the reliability needs by an additional 400-425 MW, making the total deficiency approximately 1,450 MW (or approximately 1,350 MW accounting for the effect of the initial proposed 100 MW EE/DR program).

In order to conduct an independent analysis and update of the reliability deficiency needs and to perform other work which would be useful for Staff's Contingency Plan analysis, as directed in the March 2013 Order, DPS Staff obtained the consulting services of Brattle. Thereafter, DPS Staff directed Brattle to analyze the reliability needs that would attend the retirement of the IPEC at the end of 2015. DPS Staff indicated that the updated base case in the analysis should model NRG Energy, Inc's Astoria Gas Turbine Units 10 and 11, which are expected to return to service.[33] Based on the analysis, DPS Staff confirmed the validity of the reliability needs identified in the Con Edison/NYPA February Filing, and that if IPEC Units 2 and 3 were to retire upon the expiration of its current licenses in 2013 and 2015, respectively, Southeast New York would not have enough capacity to avoid reliability violations in the summer of 2016.

[33] On June 7, 2013, NRG Energy, Inc. filed, in Case 05-E-0889, a notice of intent to return Astoria Gas Turbine Units 10 and 11 to service.

Contrary to parties' claims, we find that the various analyses performed of the potential reliability impacts associated with the retirement of IPEC provide a sufficient record and a rational basis to identify a reliability deficiency need of approximately 1,450 MW. We reject, however, parties' suggestions that the Commission should rely on the NYISO planning process to resolve these potential reliability needs, or that we should not plan for the contingency that IPEC may be retired.[34] As observed in the March 2013 Order, the NYISO's process currently assumes that IPEC will remain available, and therefore, it is not conducting the reliability contingency planning that we are conducting now.[35] We disagree that a reasonable planning approach under the circumstances should rely solely on market-based projects to appear, or that we should wait for the NYISO to "trigger" the need for the implementation of a reliability solution. In the event IPEC were unable to obtain the necessary consents and approvals to continue operating, or if Entergy could decide that continued operation of IPEC is not in its interest,[36] there would unlikely be sufficient time to address the resulting reliability needs.

The requirement that the projects included in the IPEC Reliability Contingency Plan meet a firm in-service deadline of June 1, 2016 comports with the NYISO's identified reliability

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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

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[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 <u>supra</u> 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

[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

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[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:

$$\frac{\text{Benefit}}{\text{Cost}} = \frac{\text{NPV(Energy + LineLoss + Capacity + Environmental + T + D)}}{\text{NPV(UtilityCosts + CustomerCosts + ProgramAdmin)}}$$

We note that the "customer costs" in the above formula are not paid by utility ratepayer funds, but rather by customers' own funds.

million over 15 years.[43] The estimated net resource cost savings were greater assuming IPEC is retired.

DPS Staff therefore recommends that these EE and DR programs be included in the IPEC Reliability Contingency Plan. We agree with DPS Staff that these EE and DR programs are worthwhile pursuing, given our expectation that the benefits of these projects will exceed the costs. Accordingly, we accept the EE and DR components (totaling 100 MW) of the 125 MW Revised EE/DR/CHP Program, as proposed by Con Edison and NYSERDA.

We disagree with parties that suggest the proposed EE and DR resources should be compared to the cost of the transmission and generation resources that were submitted for consideration as replacement resources for IPEC. Based on the cost effectiveness of the proposed EE and DR programs, such a comparison is unnecessary. These programs are reasonable to pursue, regardless of whether IPEC is retired.

An important consideration for some parties is the extent to which the EE and DR program's peak demand reduction efforts would be coordinated with NYSERDA and Con Edison's regular EE programs. We are persuaded that the programs will be appropriately coordinated. Moreover, the proposal has the characteristic that the incentives and program rules of the commercial and industrial programs will be uniform for both the Commission's Energy Efficiency Portfolio Standard (EEPS) kWh incentives and the incentives for the EE and DR programs which we are considering here. Other elements of these EE and DR programs, such as thermal energy storage and battery arrays, are new programs that will not affect existing EEPS programs.

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[43] The benefits of the EE and DR programs identified in the Revised EE/DR/CHP Program exceeded the costs, even with the environmental components removed. Thus, the $182 million estimate would be even higher if the environmental components were included.

Entergy asserts that reliance on EE is a major deviation from reliability system planning that could threaten system reliability if the energy efficiency program does not achieve its projected gains. We agree that reliance on EE and DR programs is relatively new. Energy efficiency, however, is not so new as to be untested. New York and several other states have accumulated significant experience with EE over the last 20 years. In fact, EE results are routinely used in the NYISO planning process as load modifiers. We are confident that EE is a proven resource that can be relied upon for many purposes, including the one at hand – ensuring reliability in the event IPEC is retired.

Many other details have been suggested by commenters, including combining EE with renewable generation at a customer location, aggregation of small thermal storage projects, and providing extra incentives for "Made in New York" solutions. Our primary goal here, however, is to obtain the peak MW reductions needed by 2016 to help protect against reliability violations which could stem from the retirement of the IPEC. We will therefore accept the proposal, as put forward by Con Edison, NYSERDA, and NYPA, without further imposing specific requirements such as these.

We recognize that the EE and DR programs would be jointly implemented by Con Edison and NYSERDA, and we seek to ensure appropriate coordination between the two entities. The proposal to maintain a "single point of customer entry" should assist in eliminating duplicative procedures and confusion for customers. We anticipate that Con Edison and NYSERDA will develop appropriate agreements to facilitate the provision of any necessary customer information and program funds from Con

Edison to NYSERDA.[44] To the extent such agreements cannot be reached after consultation with DPS Staff, a petition should be filed with the Commission for resolution.

We also find that NYSERDA's Expanded CHP Program should be pursued to obtain 25 MW, which is in addition to the 30 MW that NYSERDA estimates will be achieved in Con Edison's service territory by June 2016 under the CHP Program already approved by the Commission. We recognize that promoting CHP resources has broad and deep support among environmental, governmental, and business interests. We find that committing further funding toward CHP projects will help to advance the Commission's objective of promoting CHP, and to reduce the reliability needs identified in the NYISO's September 18, 2012 RNA. We also concur with the parties that believe that DR and CHP should, in combination, form a substantial component of the resources that are developed as part of the response to the potential retirement of IPEC. To ensure proper accounting and reporting of the CHP aspects of the Revised EE/DR/CHP Program, Con Edison and NYSERDA should develop detailed accounting procedures, reporting requirements and an implementation plan, as we are requiring with respect to the EE and DR programs.

Finally, we acknowledge NYPA's Build Smart NY Program, and will count NYPA's 15 MW target toward the identified reliability needs under the IPEC Reliability Contingency Plan. However, because this program will be funded through NYPA low cost financing that is recovered from the direct program participants, we do not need to approve the program or the

[44] Con Edison shall establish by agreement with NYSERDA, procedures for the transfer of funds to NYSERDA to repay NYSERDA for the costs it incurs in implementing the portion of the Revised EE/DR/CHP Program for which NYSERAD has responsibility. The form of this agreement, and of any amendments to this agreement, shall be filed with the Secretary as a compliance filing.

associated funding. We expect that NYPA will update the Commission in the event that changed circumstances affect the achievement of the target amount within the necessary time frame.

In this Order, we accept the 125 MW EE/DR/CHP program set forth by Con Edison, NYSERDA and NYPA, and we take account of approximately 60 MW of peak demand reduction which these parties expect to achieve from existing programs. We recognize these are modest goals for programs of this type. We believe there continues to be unrecognized, cost-effective opportunities for EE, DR, and CHP programs to meet a greater portion of the reliability needs which the IPEC Reliability Contingency Plan describes. We direct Con Edison, working with DPS Staff, NYPA, and NYSERDA, to intensify its efforts to identify and exploit these additional opportunities, and direct Con Edison to report on these efforts by February 15, 2014.

Cost Allocation

As noted above, DPS Staff, at our direction, prepared and filed a proposed methodology for allocating and recovering costs associated with the IPEC Reliability Contingency Plan, which was the subject of two technical conferences and various comments. In general, the DPS Staff's June Straw Proposal recommended that the same cost allocation methodology should be used for each element of the IPEC Reliability Contingency Plan portfolio. In this Order, and as discussed below, we are sensitive to the particular characteristics of the various elements of the portfolio, and we do not conclude that the same cost allocation methodologies should be used for all portfolio elements. Instead, we prefer to tailor the cost allocation solutions in a more granular way so that each specific portfolio element uses the methodology that best suits its particular characteristics.

A. TOTS Projects

In conjunction with their proposal for the TOTS projects, Con Edison and NYPA, along with the other NYTOs, have urged that DPS Staff's June Straw Proposal methodology should not be used to allocate the costs associated with implementing those projects. Instead, Con Edison and NYPA urge that the TOTS costs should be allocated in proportion to the shares already agreed to by the NYTOs in the context of preparing their NY Transco proposal.[45] As noted above, Con Edison, NYPA and the other NY Transco participants have jointly identified 18 transmission projects throughout the State which, if approved, could be undertaken to improve the State's transmission system. The three TOTS projects were among those identified by the proponents of the NY Transco.

In response to the NYTOs' cost allocation proposal, various commenters argued that cost allocation should be based solely upon a reliability beneficiaries pay methodology and should be consistent with the NYISO approach for reliability solutions. Some commenters were specifically critical of the NY Transco approach based upon their belief that the benefits of the three TOTS projects will accrue to Southeastern New York alone, and, at the same time, will bring higher energy costs and emissions to Upstate New York. Commenters also argued that the derivation of the NY Transco method has not been explained, and

[45] The NYTOs have agreed to a NY Transco cost allocation as follows: 5.4% for Central Hudson Gas & Electric Corp. (CHG&E), 38.3% for Con Edison, 16.7% for Long Island Power Authority (LIPA), 10.4% for Niagara Mohawk d.b.a. Nation Grid, 5.8% for New York State Electric & Gas (NYSEG), 3.4% for Orange & Rockland Utilities (O&R), 16.9% for NYPA, and 3.1% for Rochester Gas & Electric Corp. (RG&E). See, NYTO comments, dated July 22, 2013.

that its sponsors have not demonstrated that the method aligns allocated costs with benefits. Further, concerns were raised that the NY Transco method will lead to inconsistencies between TOTS solutions and non-TOTS solutions, thereby resulting in an unlevel playing field and divergence from the NYISO reliability cost allocation approach. Others contended that the NY Transco cost allocation method was previously rejected by the Commission in the April 2013 Order. Finally, some commenters urged that the public policy that is needed to define and sanction the benefits claimed for the TOTS projects has not been developed and that this proceeding was not intended as the forum in which this policy should be developed.

While we understand the commenters' concerns regarding the potential for different cost allocation methods for different solutions, we recognize several factors which weigh in favor of utilizing the proposed NY Transco approach for the three TOTS projects. Specifically, the NY Transco allocation was voluntarily developed and approved by all of the NYTOs. We acknowledge that the NYTOs have achieved a significant milestone in reaching this consensus, as they have solved a problem that can hinder the construction of infrastructure across utility service territories. In this instance, however, that barrier has been surmounted. In addition, based upon the IPEC Reliability Contingency Plan analysis, the three proposed TOTS projects were found to provide net benefits both with and without IPEC in service. We also recognize that the benefits from resource adequacy solutions for the replacement of the IPEC, such as the TOTS, do not accrue solely to downstate consumers. Rather, we agree with the NYTOs that these solutions should also provide some reliability benefits statewide. Based on these factors, we find the proposed allocation of costs and benefits to be reasonable, and support the use of the proposed NY Transco cost allocation methodology.

Finally, we note that the proposed NY Transco approach, which provides that a share of the project costs will be assumed by LIPA and NYPA, achieves a broader distribution of project costs than have been achieveable in the past. In this regard, it is significant that LIPA has already indicated its agreement with the NY Transco approach.[46] For this reason, it appears unlikely that a jurisdictional challenge from LIPA will be made.

B. EE/DR/CHP Programs

DPS Staff's June Straw Proposal was silent on cost allocation for EE, DR, and CHP projects. However, the EE/DR/CHP submissions by Con Edison and NYPA urge that the costs of these programs should be allocated to Con Edison's ratepayers, just as the costs of similar utility EE, DR, or CHP programs have been allocated in the past. No commenters raised specific opposition to Con Edison's proposal. While some commenters favored a single cost allocation approach for all solutions, some favored Con Edison's cost allocation proposal for these programs. NYC stated that cost allocation of EE/DR/CHP projects need not be the same as that afforded to generation and transmission projects. Rather, NYC contends that the "benefits associated with EE/DR/CHP projects are so specific to the utility service territory in which they are located that costs associated with those measures should not be spread to other utilities."[47]

Con Edison will have the ability to target its EE/DR program to help relieve its local distribution system, thereby

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[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. <u>EE/DR/CHP Programs</u>

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.

[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

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[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

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[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.

<u>Independent Power Producers of New York, Inc. (IPPNY)</u>:

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.

<u>Municipal Electric Utilities Association (MEUA)</u>:

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."

<u>New York City Hispanic Chamber of Commerce, Inc.</u>:

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.

<u>New York City Office of Long-Term Planning and Sustainability (NYC)</u>:

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.

<u>Paul Heagerty</u>:

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.

<u>Pure Energy Infrastructure, LLC (Pure Energy)</u>:

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.

<u>Queens Chamber of Commerce</u>:

The Queens Chamber of Commerce expresses concern about the cost of the June Straw Proposal.

<u>Retail Energy Supply Association (RESA)</u>:

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

[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

[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. BACKGROUND

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. The Projects Will Enhance Electric Reliability

1. The Projects Will Improve LOLE

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. The Projects Will Enhance Transmission Availability

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 <u>Potential Downstate Generation Retirements</u>

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. <u>The Projects Will Create Long Term Economic Development Benefits</u>

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. <u>The Projects Will Result in Reduced Environmental and Health Impacts</u>

1. <u>Emissions Reductions</u>

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. <u>Leveraging Existing Rights-of-Way</u>

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

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[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

[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

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[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. <u>The Cost Recovery Mechanism is Reasonable</u>

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 Comply With Order 1000

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.

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[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.

[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:

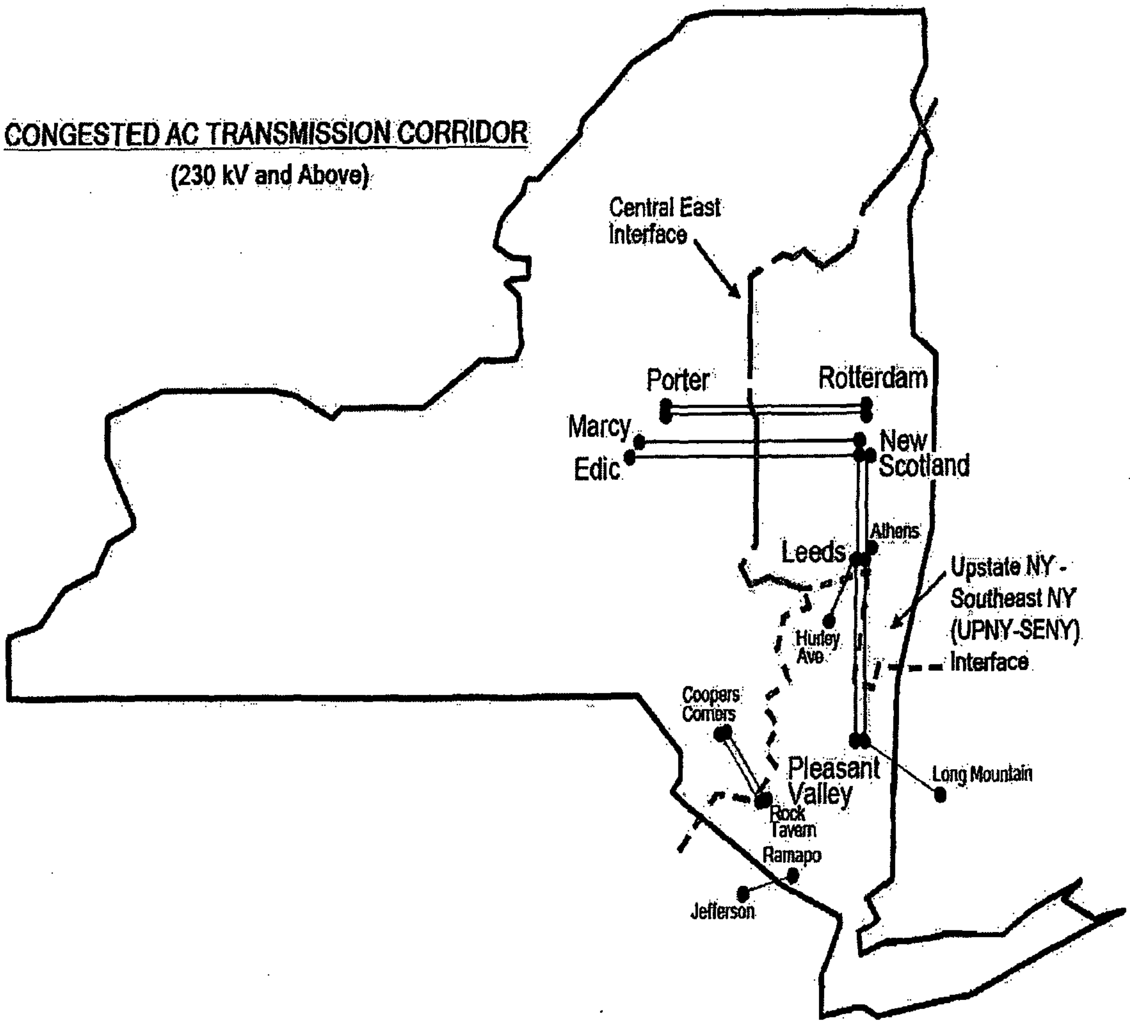
1. A proceeding is instituted to examine proposals that meet the congestion reduction objectives set forth in this Order.

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
Upstate NY - Southeast NY (UPNY-SENY) Interface
Hurley Ave
Coopers Corners
Pleasant Valley
Long Mountain
Rock Tavern
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

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[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

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[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 <u>State Register</u> 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

[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

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[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.

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[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

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[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

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[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

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[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

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[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.

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[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

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[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

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[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

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[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

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

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[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

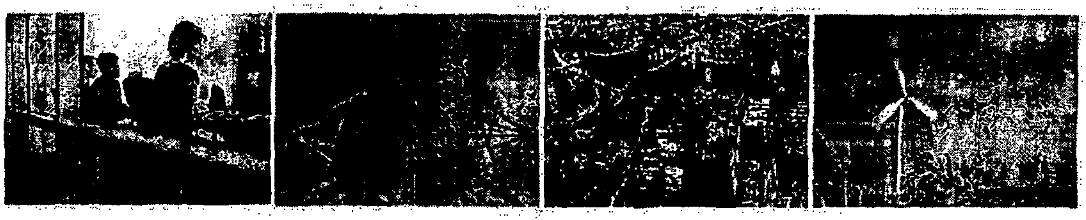
xi. Exhibit E-6 (88.6): Effect on Transportation

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.

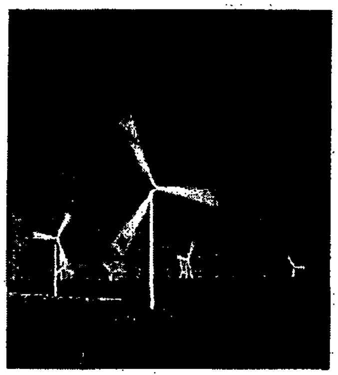
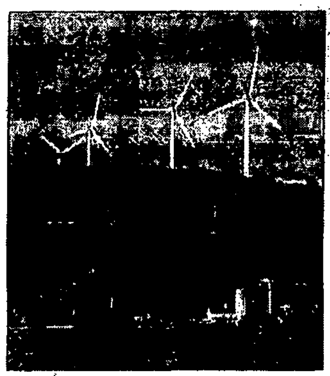
Two: Due to New York's existing transmission limitations, new generation, additional demand response, and limited transmission upgrades would be the likely potential solutions in response to an Indian Point closure by the summer of 2016.

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.

NEW YORK INDEPENDENT SYSTEM OPERATOR

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 dispatchability such as plant commitment and economics of the system

Step 5: An identification and rank ordering of the transmission constraints that impact the dispatchability 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:

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[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 8 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.

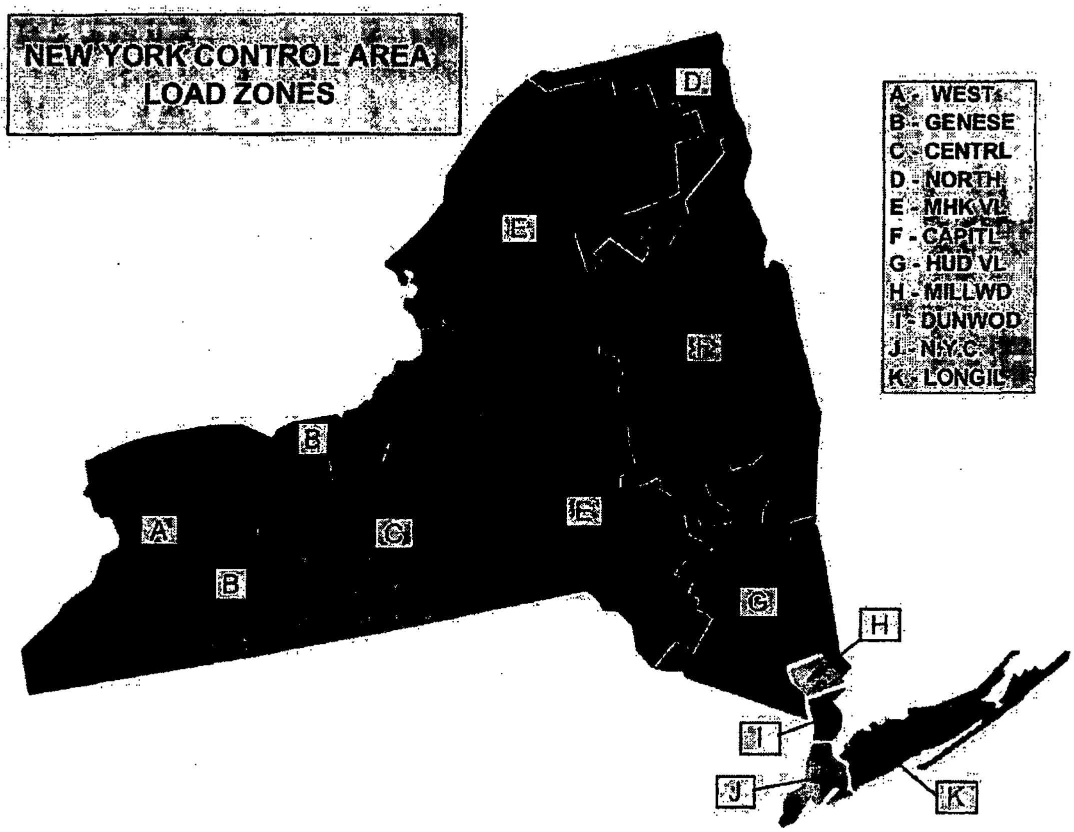
Finally, the study determined that almost 9% of the potential upstate wind energy production will be "bottled" or not deliverable because of local transmission limitations. The study identified feasible sets of transmission facility upgrades to eliminate the transmission limitations. These upgrades were 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 dispatchability such as plant commitment and economics of the system

Step 5: An identification and rank ordering of the transmission constraints that impact the dispatchability 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).

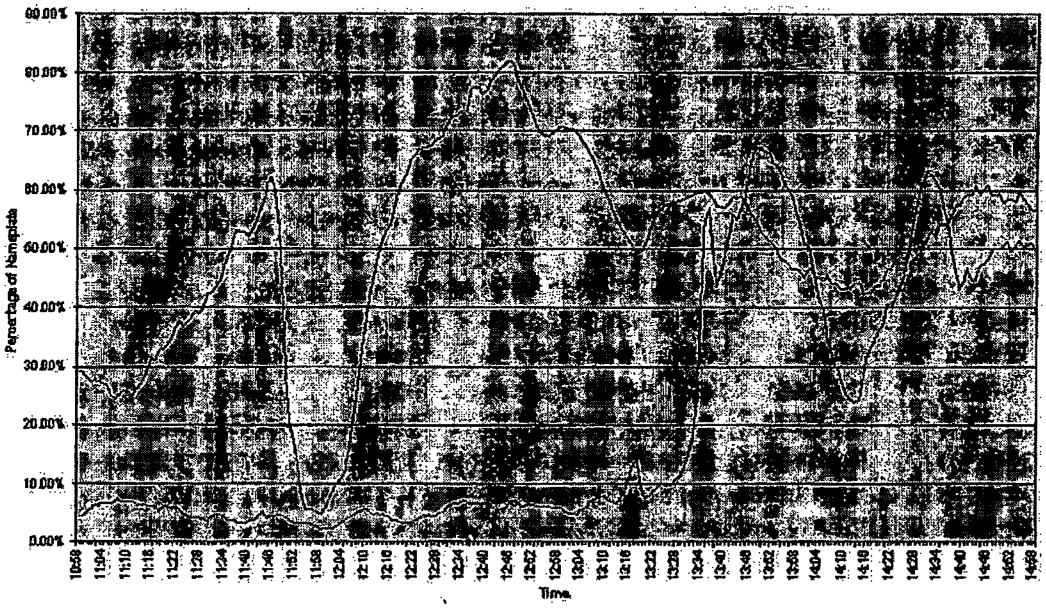


Figure 5.1: High-Speed Cutout Event approx. 12 noon on 6/10/08

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.

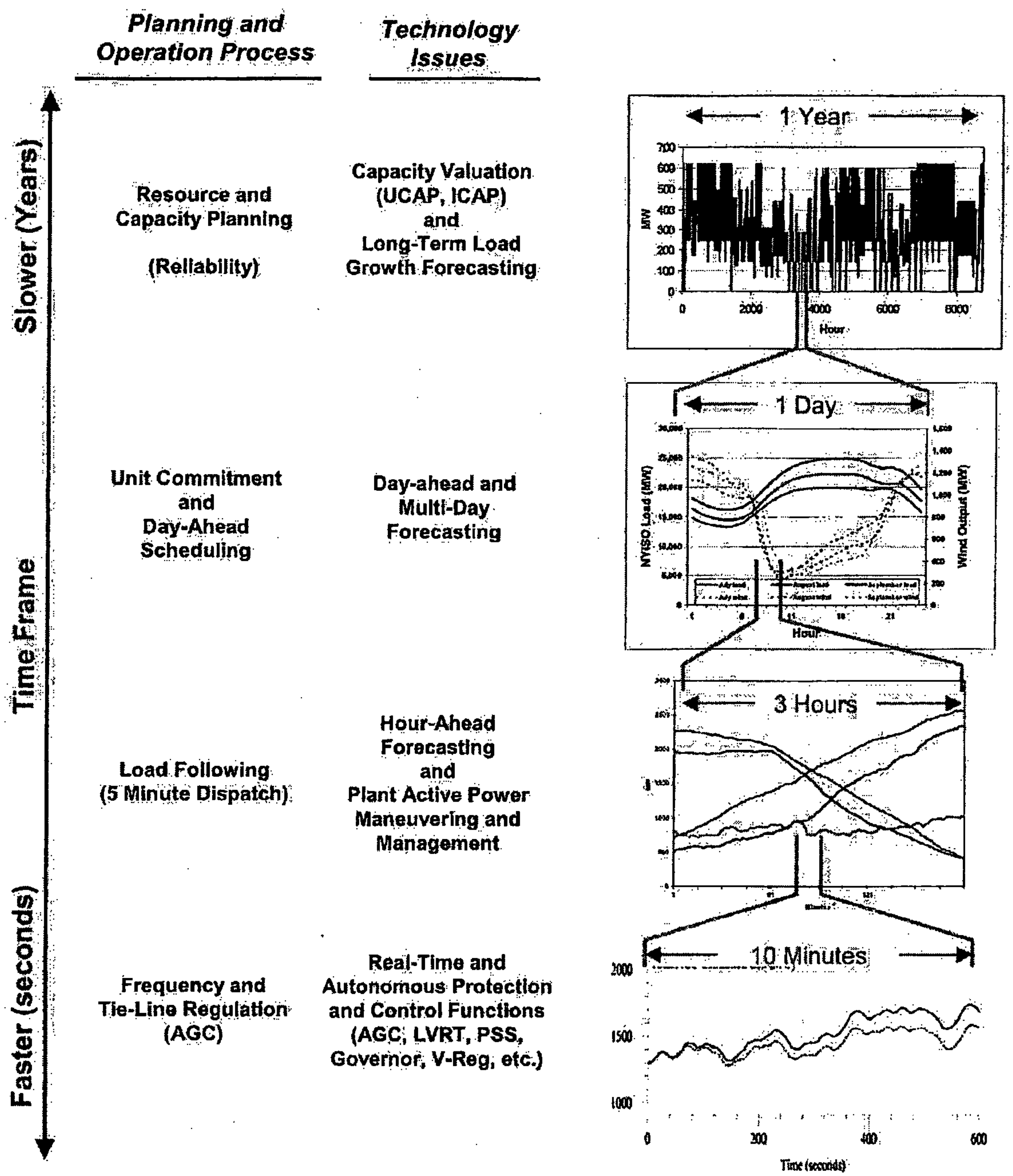


Figure 5.2: Power System Time Scales

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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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.

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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.

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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.

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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.

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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.

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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

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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.

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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

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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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