Draft

2009 Northeast Coordinated Electric System Plan
ISO New England, New York ISO and PJM

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Table of Contents

1 EXECUTIVE SUMMARY 1
2 INTRODUCTION 4
3 SUMMARIES OF RTOS' SYSTEM PLANS 5
3.1 PJM 2009 Regional Transmission Expansion Plan (RTEP) 5
3.2 NYISO 2009 Comprehensive Reliability Plan 5
3.3 ISO-New England 2009 Regional System Plan 6
3.4 Order 890 and Economic Studies 7
3.4.1 PJM Economic Studies 7
3.4.2 NYISO Economic Studies 8
3.4.3 ISO New England Economic Studies 10
3.5 Summary 12
4 SUMMARIES OF INTERREGIONAL STUDIES 13
4.1 Transmission Improvements Having Interregional Impacts 13
4.1.1 PJM 500 kV Expansion Plan 13
4.1.2 Queue Projects with Potential Interregional Impacts 13
4.1.3 Status of Planned Interconnections between the ISO/RTOs 15
4.1.4 Loss-of-Source Analyses 15
4.1.5 Plattsburgh – Vermont Upgrade 17
4.2 Reliability Analysis of the NYISO/PJM Area 18
4.3 Market Efficiency Analysis 19
4.3.1 Market Efficiency Analysis of the NYISO/PJM Area 20
4.3.2 Market Efficiency Analysis of the NYISO/ISO-NE Area 23
5 ADDITIONAL COORDINATED PLANNING ACTIVITIES AND ISSUES 24
5.1 Coordination of Studies and Databases 24
5.2 Northeast Power Coordinating Council 24
5.2.1 Coordinated Planning 25
5.2.2 Resource Adequacy Analysis (CP-8) 25
5.2.3 NPCC Overall Transmission Assessment 26
5.2.4 RFC 2014 Long-Term Assessment of Transmission System Performance 27
5.3 IRC Activities 27
5.4 NERC ERAG 28
5.5 Available Transfer Capability vs. RFC - NPCC Seasonal Study Incremental Transfer Capability (ITC) 29
5.5.1 ATC/RFC-NPCC methodology differences 30
5.5.2 ATC Results 31
5.6 NERC LTRA 32
5.7 Eastern Interconnection Planning Collaborative 32
5.8 Fuel Diversity Issues 34
5.8.1 New England 34
5.8.2 New York ISO 35
5.8.3 PJM 35
5.9 Summary 36
6 KEY ENVIRONMENTAL ISSUES WITH POTENTIAL INTERREGIONAL IMPACTS 37

6.1 EPA's Criteria Pollutants Affecting Power Plants ... 38
6.1.1 Sulfur Dioxide (SO_2) ... 38
6.1.2 Nitrogen Dioxide (NO_2) ... 39
6.1.3 Fine Particulates ($PM_{2.5}$) ... 39
6.1.4 Ozone (O_3) ... 39
6.1.5 Ozone Attainment and SO_2 Reductions ... 40
6.2 Mercury ... 45
6.3 Carbon Dioxide (CO_2) Regulation and Cap and Trade Programs ... 45
6.3.1 RGGI ... 45
6.3.2 Other Regional Cap and Trade Programs ... 47
6.3.3 Federal Cap and Trade Legislation ... 48
6.3.4 EPA's CO_2 Regulation and Future Air Regulation Strategy ... 48
6.4 Power Plant Cooling Water Issues ... 49
6.5 Coal Combustion By-Products ... 49
6.6 Summary and Conclusions ... 50
7 RENEWABLE PORTFOLIO STANDARDS ... 51
7.1 New England States ... 52
7.2 New York ... 52
7.3 PJM States ... 53
7.4 Interconnection Queues ... 53
7.5 Conclusions ... 54
8 WIND AND RENEWABLE RESOURCE STUDIES ... 55
8.1 DOE and NERC Wind Integration Activities ... 55
8.1.1 Eastern Wind Integration and Transmission Study ... 55
8.1.2 NERC's Integration of Variable Generation Task Force ... 56
8.2 Wind Development and Integration Issues in New York, New England and PJM ... 56
8.2.1 New York ... 57
8.2.2 New England – Update on the New England Wind Integration Study ... 59
8.2.3 PJM ... 63
8.2.4 Generic Wind Integration Issues ... 64
8.2.5 Summary ... 65
8.3 Imports from Eastern Canada ... 65
8.4 Summary ... 66
9 DEMAND SIDE RESOURCE DEVELOPMENT ... 67
9.1 PJM ... 67
9.2 New York ISO ... 68
9.3 ISO New England ... 69
9.4 Conclusions ... 70
10 PLANS FOR ADDITIONAL JIPC ANALYSIS ... 71
10.1 Market Efficiency Analysis ... 71
10.2 Transmission Analysis ... 71
10.3 Transmission Cost Allocation ... 71
10.3.1 Status of Order 890 ... 72
11 SUMMARY AND CONCLUSIONS ... 72
11.1 Summary ... 72

11.2 Conclusions 74
12 APPENDICES 75
12.1 Cost Allocation Matrix of the ISO/RTOs 75
12.2 References 84

Preface

This report is a compilation of summaries of activities that have been completed or are currently ongoing with the Joint ISO/RTO Planning Committee (JIPC) during the year 2009. The report also includes discussion of the Northeast Power Coordinating Council (NPCC), the Reliability*First* Corporation, and the North American Electric Reliability Corporation (NERC).

1 Executive Summary

ISO New England Inc. (ISO-NE), the New York Independent System Operator (NYISO), and the PJM Interconnection (PJM) each produce their own annual regional plan covering the needs of the region that each ISO/RTO serves. In addition, these ISO/RTOs work jointly under a formal protocol studying numerous issues related to interregional electric system problems, developments and performance. The intent of collaboration under the joint planning protocol is to ensure that the electric system is planned on a wider interregional basis and is proactive and well coordinated. This report covers the current joint activities and their status as well as planned activities to be conducted under the protocol.

ISO New England (ISO-NE), New York ISO, and PJM follow a planning protocol to enhance the coordination of planning activities and address planning seams issues among the interregional balancing authority areas.[1] Hydro-Québec TransÉnergie, the Independent Electric System Operator (IESO) of Ontario and the New Brunswick System Operator participate on a limited basis to share data and information. The key elements of the protocol are to establish procedures that accomplish the following tasks:

- Exchange data and information to ensure the proper coordination of databases and planning models for both individual and joint planning activities conducted by all parties
- Coordinate interconnection requests likely to have cross-border impacts
- Analyze firm transmission service requests likely to have cross-border impacts
- Develop the Northeast Coordinated System Plan (NCSP) on a periodic basis
- Allocate the costs associated with projects having cross-border impacts consistent with each party's tariff and applicable federal or provincial regulatory policy

To implement the protocol, the Joint ISO/RTO Planning Committee (JIPC) was formed, and an open stakeholder group called the Inter-Area Planning Stakeholder Advisory Committee (IPSAC) was created to discuss work conducted by the JIPC.[2] Through the open stakeholder process, the JIPC has made progress addressing several interregional balancing authority area issues over the past year, including:

- The addition of transmission upgrades, including upgrades in the Plattsburgh-VT area
- The coordination of interconnection queue studies and transmission improvements to ensure reliable interregional planning
- Cross-border transmission security issues, including the consideration of loss-of-source (LOS) contingencies in New England
- Studies aimed at investigating generator deliverability and load deliverability issues
- Market efficiency analyses, reflecting coordinated models of the three ISO/RTOs and neighboring regions

[1] Additional information about the Northeastern ISO/RTO Planning Coordination Protocol ("Protocol") is available online at http://www.interiso.com/public/document/Northeastern%20ISO-RTO%20Planning%20Protocol.pdf. An *RTO* is a Regional Transmission Organization that is responsible for a wide geographic area known as a balancing area. ISO New England is the RTO for Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. The New York Independent System Operator (NYISO) is responsible for New York State. The PJM Interconnection is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia.

[2] See "Inter-ISO Planning," IPSAC meeting notices; http://www.interiso.com/default.cfm.

- Reporting on the effects of environmental regulations, including the integration of wind and other renewable resources, a as well as the effect of demand side resources on interregional operations and planning

Interregional planning starts with the individual regional plans developed by the three ISO/RTOs through their open stakeholder processes. These plans address resource adequacy needs, discuss the development of transmission upgrades and new generation interconnections, and include other planning issues. The ISO//RTOs also conduct economic studies that assist policy makers and transmission developers. (Section 3) The regional plans are coordinated with neighboring systems. This is shown by studies of transmission and generation facilities affecting interregional system performance, such as major 500 kV and 765 kV expansion plans in PJM, and new ties between NYISO and the neighboring PJM and ISO-NE systems. (Section 4)

The JIPC has conducted several interregional studies. Loss of source (LOS) studies show an expected limit in the 1,400 MW to 1,500 MW range and are updated as a part of ongoing transmission studies. These LOS studies performed in the planning horizon are only indicative of changes that may be expected to these limits. The actual limits are set by operational planning studies. A prefeasibility study of a new tie between Plattsburgh, New York and Vermont demonstrates the tie may address a number of reliability issues in the area. The study also shows a new tie would increase allowable transfers across Central East, into and out of New York's North Country to Vermont, and into New England's Phase II facility. The JIPC also conducted studies to address generation deliverability and load deliverability issues near the PJM/NYISO border and market efficiency analyses performed with focuses on the NYISO/PJM and the NYISO/ISO-NE border areas. (Section 4)

In addition to studies conducted by the JIPC, there are several other interregional planning activities supported by the ISO/RTOs. These include studies coordinated by Reliability Councils, the North American Electric Reliability Corporation, and the ISO/RTO Council. Planning issues across the entire interconnection will be addressed by the newly formed Eastern Interconnection Planning Collaborative. Natural gas issues have been coordinated among the ISO/RTOs throughout the Northeast. (Section 5)

The northeastern states are subject to many environmental regulations, including ozone standards, green house gas (such as carbon dioxide) restrictions, and use of cooling water. The regulations have the potential to affect generator economic performance by increasing costs for emission allowances, new controls, and cleaner fuels. The regulations may also affect reliability by limiting generator energy production and reducing capacity output. Since interregional system performance could change as a result of new generation patterns, the JIPC monitors environmental regulations for potential system impacts. (Section 6)

Most of the states served by PJM, NYISO, and ISO-NE have renewable portfolio standards or related energy policies. The queue for renewable resource development in the three ISO/RTO regions totals over 55,000 MW, over 90% of which is wind resources, including significant offshore wind projects. These projects, if developed, would be sufficient to meet the RPS short term goals while recognizing that contributions could come from other RPS sources not in the queues. The RPS can be met by a combination of renewable generation, energy efficiency, and alternative compliance payments that also serve as a cap on the price paid for renewable energy. (Section 7)

The growth of wind resources creates system integration and operating challenges for all three ISO/RTOs. These include transmission development to interconnect these wind projects, system operating flexibility to accommodate wind's variability, operator awareness and practices, and the need for wind generator plant performance and standards. The JIPC is monitors the separate evaluations of wind issues being conducted individually by the three ISO/RTOs, the Department of Energy (DOE), and the North American Electric Reliability Corporation (NERC). (Section 8) Many of the Northeastern states are also promoting demand resources and their use is reflected in each of the ISO/RTOs planning processes and wholesale markets. (Section 9).

The JIPC recognizes the need for further work based on input from the IPSAC. Future plans call for conducting additional interregional economic analyses that may identify potential transmission bottlenecks, and trigger the need for transmission planning analyses. In addition, cross border transmission cost allocation discussions are planned following completion once projects have been identified. The ISO/RTOs regularly provide the status of seams issues, in a report, which includes the schedules for addressing the cross-border planning issues[3]. (Section 10)

Planning is subject to many uncertainties, revised forecasts, and applications of new technologies. Because planning is continuous, the NCSP results and activities represent a snapshot in time. The JIPC will continue to coordinate planning issues and efforts across ISO/RTO boundaries and remain alert to changes in system conditions and forecasts. Planning activities will also include the impact of the recent economic downturn on load and fuel[4]. The use of new technologies will be considered as a factor that may affect future transmission development.

Interregional studies are increasing in importance and the need for studies of the future system is vital. In addition to the JIPC, the three ISO/RTOs participate in other interregional study groups that support the Northeast Power Coordinating Council (NPCC), the Reliability*First* Corp. (RFC), the North American Electric Reliability Corporation (NERC), and the ISO/RTO Council (IRC). For the Northeast, the three ISO/RTOs will continue and expand planning activities that address the mutual interactions of the planned high voltage transmission systems of all regions, with particular emphasis on major planned transmission additions and future system power transfer capabilities. The three ISO/RTOs also remain committed to the IPSAC open stakeholder process as a forum to discuss interregional planning activities.

[3] The Seams Report is available online at http://www.iso-ne.com/regulatory/seams/2008/index.html.

[4] On February 5, 2009, the Energy Information Administration reported that nationwide fourth quarter electric energy consumption had decreased by a full 1%.

2 Introduction

The New York Independent System Operator (NYISO), ISO New England (ISO-NE), and the PJM Interconnection actively coordinate system planning. In the fall of 2003, they recognized that a broader initiative including other transmission operators in the Northeast would be beneficial and accordingly, in January 2003, an inter-area Transmission Coordination Task Force (TCFT) was formed including ISO-NE, NYISO, PJM, and the Canadian members of Northeast Power Coordinating Council (NPCC). NPCC staff also participated in these discussions. This led to the development of a protocol for coordinating these planning activities that was formalized in December 2004 and subsequently filed with FERC. The Joint Interregional Planning Committee (JIPC) carries out the coordinated planning of the combined ISO-NE, NYISO and PJM systems and the Interregional Planning Stakeholder Advisory Committee (IPSAC) provides useful public input to the planning process and its activities.

While not parties to the protocol, the Independent Electricity System Operator of Ontario (IESO), Hydro-Québec TransÉnergie (HQ), and New Brunswick Power (NB Power) agreed to participate on a limited basis in the data-sharing and information-exchange process. They also participate in interregional planning studies for projects that may have inter-area impact, to ensure better coordination in the development of the power system. Planning activities are conducted in close coordination with the Northeast Power Coordinating Council (NPCC) and the Reliability First Corporation (RFC).

To report periodically on these interregional planning activities, a Northeast Coordinated System Plan (NCSP) describes these activities and their progress. The last NCSP was produced in 2008. Since then, periodic updates have been provided to the IPSAC. For example, improved interregional coordination of fuel diversity issues has improved the overall reliability of the interconnected network. Other issues that were coordinated by the JIPC and discussed with IPSAC included environmental regulations, coordination of interregional resource adequacy and transmission studies, and other analyses.[5] This document is an update on some of these interregional activities occurring since the previous report was issued in March 2009.

This report is organized as follows: Section 3 provides summaries of the ISO/RTO's annual regional plans. Section 4 summarizes the interregional studies conducted by the JIPC. Section 5 covers additional coordinated planning activities and issues. Section 6 covers key environmental issues with potential interregional impacts. Section 7 summarizes renewable portfolio standards. Section 8 summarizes wind and renewable resource studies. Section 9 discusses demand resources and Section 10 describes plans for additional interregional studies. Finally, Section 11 presents a report summary and conclusions and Section 12 contains a matrix that provides additional information on the existing transmission cost allocation methods for all the ISO/RTOs.

The planning studies discussed in this report are based on 2009 load forecasts and other projected system conditions.

[5] Previous IPSAC studies can be found at http://www.interiso.com/documents.cfm.

3 Summaries of RTOs' System Plans

This section summarizes the ISO/RTOs' latest individual plans. Because the planning processes are continuous, interested stakeholders are encouraged to participate in each of the ISO/RTO planning meetings to obtain the latest information.

3.1 PJM 2009 Regional Transmission Expansion Plan (RTEP)

The PJM Regional Transmission Expansion Plan (RTEP) is published annually in February. The 2009 RTEP describes analysis performed over a range of study years and system conditions, including studies of a 2014 summer peak model. The load forecast used is based on a weather normalized summer peak demand forecast, which has a load growth rate of 1.5% annually over the next 10 years, from 137, 948 MW in 2008 to 160,107 MW in 2018, an increase of 22,159 MW over the decade. Individual geographic zone growth rates vary from 0.9% to 2.6%. In developing the RTEP, PJM performs comprehensive power flow, short circuit and stability analyses. These studies assess the impacts of forecast firm loads and transactions with neighboring systems, existing generation and transmission assets, and anticipated new generation and transmission facilities.

The PJM Board of Directors (BOD) has authorized more than $15 billion of transmission upgrades and additions since the first Board approved projects in 2000. Nearly $3.5 billion of these upgrades are under construction or already in service. This figure includes more than $1.8 billion that were approved in 2009 alone. Over $12 billion of the total represents baseline transmission network upgrades in the PJM footprint to ensure that the established reliability criteria will continue to be met. Approximately $3 billion is for additional transmission upgrades that will maintain reliability for nearly 50,000 megawatts (MW) of new generating capacity resources and merchant transmission projects.

The 2009 RTEP studies included all previously approved PJM backbone transmission projects. These include: the 2006 approved 502 Junction- Loudoun 500 kV transmission line (TRAIL), the 2007 approved Susquehanna-Lackawanna-Jefferson-Roseland 500 kV circuit, the Amos-Kemptown 765 kV circuit (PATH), and the Possum Point-Calvert Cliffs-Indian River-Salem 500 kV Circuit-Mid Atlantic Power Pathway (MAPP). In addition to the backbone projects, RTEP includes the 2006 approved 500kV Carson-Suffolk line in Virginia and 500 kV Jacks Mountain dynamic reactive project in western Pennsylvania, and the 2008 approved 500 kV Branchburg-Roseland-Hudson line in northern New Jersey. The critical need for these facilities was reexamined in the 2009 RTEP. As a result of this analysis the portion of the portion of the MAPP line from Indian River to Salem was removed from the 2009 RTEP due to delayed need based on the most recent load and generation assumptions. In addition, the 2009 RTEP resulted in the adjustment in the required date for the PATH line from 2013 to 2014. The 2009 RTEP affirmed the need and timing for the remaining backbone projects. The many other upgrades across PJM are discussed in more detail in the 2009 RTEP and on the Planning/RTEP pages of the PJM website. All PJM backbone projects continue to be evaluated annually and as changing system conditions warrant.

3.2 NYISO 2009 Comprehensive Reliability Plan

The 2009 Reliability Needs Assessment RNA indicated that the forecasted baseline system meets applicable reliability criteria for the next 10 years, from 2009 through 2018, without any resource additions. There are three primary reasons the 2009 RNA does not identify reliability needs:

- **Facility additions –** Approximately 1,714 MW above the 2008 RNA resource assumptions, which include approximately 800 MW of new wind capacity, with a lower MW level of scheduled generation retirements than in the 2008 RNA, have been incorporated into the 2009 RNA Base Case. In addition, the continued viability of the Transmission Owner (TO) Updated plans identified in the 2008 CRP and contained in the Base Case for the 2009 RNA, maintained similar transfer limits between the 2008 and 2009 CRPs.

- **Energy Efficiency Portfolio Standard (EEPS) proceeding –** Pursuant to the EEPS, the New York Public Service Commission (PSC) has taken the initial steps to implement its jurisdictional portion of the Governor's initiative to lower energy consumption on the electric system by 15% of the 2007 forecasted levels by 2015. The PSC authorized in 2005 continued spending of $175 million annually through July 2011 on Systems Benefits Charge Programs, and an additional $160 million annually for energy efficiency programs was authorized in the June 23rd EEPS Order, totaling approximately $335 million per year.[6]

  Using conservative assumptions appropriate to a baseline reliability analysis and current authorized spending levels, the NYISO projected a reduction of approximately 5% of peak load from the previously forecasted levels by 2015. The resulting 2,100 MW decrease in the peak load forecast in 2018 largely contributed to the NYISO's determination that there are no reliability needs in the Base Case. Additional EEPS program spending would further delay reliability needs as determined through scenario analysis, with increased EEPS penetration levels[7].

- **Increased registration in Special Case Resource (SCR) –** The NYISO has experienced a significant increase in the registration of the SCR programs that have effectively reduced the need for additional capacity resources to the system based on customer pledges to cut energy usage on demand. This level of demand response is in addition to the energy efficiency efforts associated with the EEPS. The NYISO currently has registrations of approximately 2,084 MW of SCRs, an increase of 761 MW of resources over the SCR levels included in the 2008 RNA.

3.3 ISO-New England 2009 Regional System Plan

ISO New England's 2009 Regional System Plan (RSP09) was published October 16, 2009. It shows a forecasted annual average peak load growth of New England of 1.2 %, with the peak projected to increase from the historic peak of 27,765 MW in 2008 to 30,960 MW in 2018. In 2009, ISO-NE conducted its second Forward Capacity Auction (FCA) for the year 2011/12 and this resulted in 37,283 MW of generation and demand response resources clearing the auction. If all these resources are still committed and operating by 2011 and beyond, they would be sufficient to meet the resource adequacy needs through 2018. This amount includes approximately 2,900 MW of demand resources[8].

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[6] The PSC has authorized the collection of $160 million annually. The June 23rd Order also called for the expenditure of an additional $170 million annually through 2011, for a total of $330 million annually during that period. This $330 million amount would be incremental to the $175 million annually in SBC spending that the PSC authorized for the five year period 2006-2011.

[7] More information on EEPS is available at http://www.dps.state.ny.us/Case_07-M-0548.htm

[8] Since the issuance of RSP09, the third FCA was held and approximately 36,996 MW will be used to calculate capacity payments.

Since 2002, over 300 transmission projects have been completed. The October 2009 Transmission Project Listing shows a total of 201 transmission projects that are proposed, planned or under construction throughout New England, several of which are major projects.

In addition to providing information on the New England region's load forecast, resource adequacy outlook, and transmission needs, RSP09 includes discussions of:

- Energy and load growth
- Capacity needs and resources
- Operating reserves
- Fuel diversity
- Environmental policy issues
- Integration of new technologies
- System performance and production cost studies
- Transmission system
- Interregional planning and
- Regional, state and federal initiatives

3.4 Order 890 and Economic Studies

As one of the principles outlined for planning in Order 890[9], each of the ISO/RTOs is required to conduct an open and transparent transmission planning process that incorporates market responses into the assessments of system needs. Aspects of the ISO's planning process, including planning methods that consider the use of demand-side resources, the process for transmission owners to develop local improvements, and dispute resolution, have been implemented as part of compliance with FERC Order 890. The economic planning studies that are required under each ISO/RTO's OATTs provide stakeholders with information on the economic and environmental performance of the system under various system conditions and expansion scenarios.

PJM Economic Studies

PJM annually performs a market efficiency analysis following the completion of the near-term reliability plan for the region. PJM's market efficiency planning analyses are based on the same starting assumptions applicable to the reliability planning phase of the RTEP development. In addition, key market efficiency input assumptions used in the projection of future market inefficiencies include load and energy forecasts for each PJM zone, fuel costs and emissions costs, expected levels of potential new generation and generation retirements, and expected levels of demand response. PJM will input its study assumptions into a commercially available market simulation data model that is available to all stakeholders. The data model contains a detailed representation of the Eastern Interconnection power system generation, transmission and load.

[9] Order 890 requires that ISO/RTOs comply with 9 planning principles. A summary of these, and their impact, is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2007/may162007/pto%27s_summary_of_local_planning_requirements_under_order_no._890.pdf. Economics studies are required as part of Order 890.

The metrics of economic inefficiency include historic and projected congestion. The measures of historic congestion are gross congestion, unhedgeable congestion, and pro-ration of auction revenue rights. The measure of projected congestion is based on a market analysis of future system conditions. This market analysis results in future projections of the congestion and its binding constraint drivers. These congestion measures are posted and available to stakeholders by binding constraint and form the basis for PJM and stakeholder development of remedies. Transmission plans from the reliability analysis or a new plan presented that economically relieves historical or projected congestion are candidates for market efficiency solutions. The successful candidates will be those facilities that pass PJM's FERC-approved threshold test and bright line economic efficiency test. The PJM bright line test is a cost-benefit metric that ensures only projects with sufficient stakeholder benefits proceed. Project benefits include recognition of a projects energy market benefit which includes production costs and load energy payments.

Through the 2008 RTEP, the PJM Board had not approved an Economic Efficiency project as a result of the annual market efficiency analysis. This is directly attributable to the substantial projected congestion relief due to the major 500 kV, 765 kV and direct current backbone projects included in RTEP due to reliability as the primary driver (PJM backbone projects are discussed in a previous section of this report).

The 2009 RTEP Market Efficiency analysis produced a a market efficiency project at Altoona-Bear Rock in western Pennsylvania. This project will relieve historical real-time congestion that is sensitive to west to east transfers and new local wind generation.

2009 RTEP also marked PJM's increased attention to interregional market efficiency analysis. Initial studies were set up to model the area of North New Jersey and Southeast New York with PJM's nodal market efficiency model. The results of this initial joint market efficiency modeling are reported in Section 4.3 of this report. It is anticipated that future work will expand the detail and accuracy of this modeling and begin to address economic efficiency issues across this important interface.

PJM has additional market efficiency analysis under way on its interfaces to the south and west. These analyses include TVA, Duke Energy, AEP, other interested stakeholders, and the MISO. The analyses are ongoing and investigating persistent congestion issues as well as potential interface upgrades.

PJM's 2009 RTEP Plan is available online at http://www.pjm.com/planning.aspx.

NYISO Economic Studies

In response to FERC Order No. 890, the NYISO has implemented a new overall planning process pursuant to Attachment Y of its Open Access Transmission Tariff (OATT, or the Tariff) to assess both historic and projected congestion on the New York bulk power system. This new process, known as the Congestion Assessment and Resource Integration Study (CARIS), will estimate the economic benefits of relieving that congestion by studying the effect of integrating potential generic transmission, generation and demand response resources as solutions to the congestion. From these estimates, NYISO expects specific economic projects to be proposed for economic assessment. CARIS builds on the NYISO's existing Comprehensive Reliability Planning Process (CRPP). Together with the Local Transmission Planning Process (LTPP) and the CRPP, the CARIS completes the NYISO's new overall Comprehensive System Planning Process (CSPP). The LTPP is the first step in the CSPP. When the reliability planning process is approved by the NYISO's board of directors, the CARIS begins, starting from a reliable system as described in the approved Comprehensive Reliability Plan (CRP).

NYISO selected the three interfaces with the largest production cost savings potential as targets for CARIS studies. These interfaces are the upper Hudson Valley (Study 1: Leeds-Pleasant Valley), central New York (Study 2: Central East), and western New York (Study 3: West Central). The NYISO also evaluated the impact of factors on congestion in the three study areas by conducting a series of ten scenarios selected by the NYISO and its stakeholders. These scenarios evaluated potential changes in environmental emission requirements, the amount of resources added through the State Renewable Portfolio Standard,[10] savings realized from the State Energy Efficiency Portfolio Standard,[11] generation retirements and additions, and changes in forecasted energy consumption.

In addition to the statewide production cost savings for each generic solution, the NYISO has also provided, for informational purposes, an analysis of additional metrics for each study, including (a) emission costs/tons, (b) generator payments, (c) LBMP load payments, (d) installed capacity (ICAP) MW impact, (e) losses on the bulk power transmission system, and (f) transmission congestion contracts (TCCs) or congestion rents.

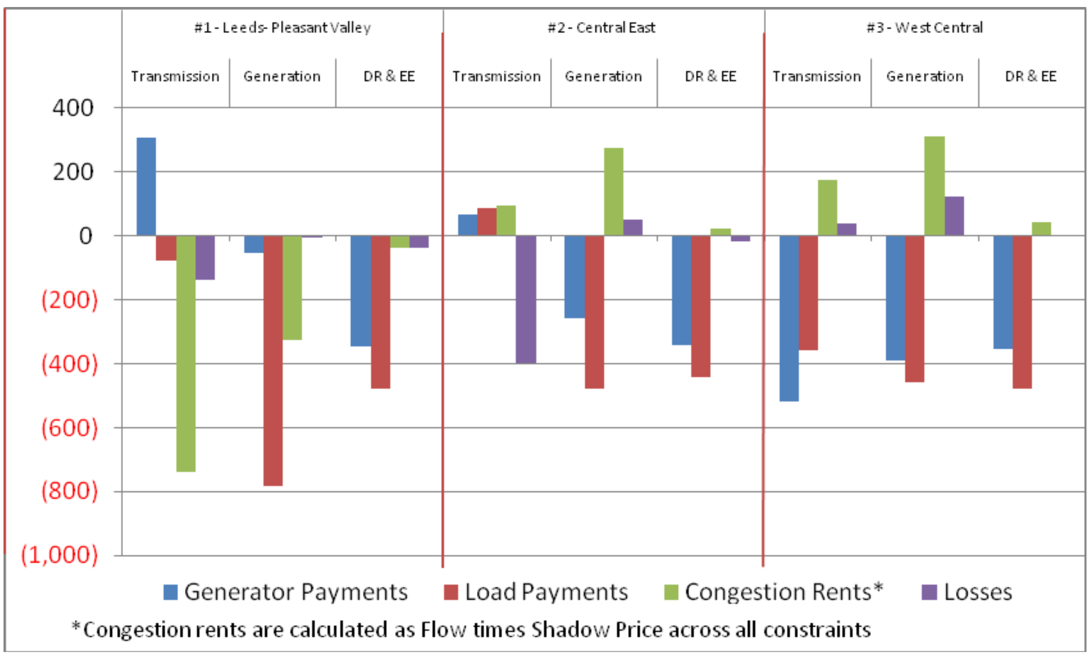

Figure 3-1: Projected Aggregate Changes in NYCA Generator Payments, Load Payments, Congestion Rents, & Losses (2009-2018)

The New York 2009 Reliability Needs Assessment (RNA) is available at http://www.nyiso.com/public/webdocs/newsroom/current_issues/rna2009_final.pdf

The 2009 New York ISO Comprehensive Reliability Plan is available at

[10] NYSPSC CASE 03-E-0188. Order Regarding Retail Renewable Portfolio Standard. September 24, 2004.
[11] NYSPSC CASE 07-M-0548. Order Establishing Energy Efficiency Portfolio Standard And Approving Programs. June 23, 2008.

http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/CRP__FINAL_5-19-09.pdf

ISO New England Economic Studies

ISO New England Economic Studies provide a range of information that can assist market participants and other stakeholders in evaluating various resource and transmission options for participating in New England's wholesale electricity markets. Under Attachment K to the OATT, the ISO is required to provide a forum for stakeholder review of the impacts of alternative system-expansion scenarios. This includes information on system performance, such as estimated production costs, load-serving entity energy expenses, estimates of transmission congestion, and environmental metrics. The ISO analyzed a series of scenarios reflecting various changes in demand and resource mixes and characteristics.

The purpose of these studies is to test future resource additions and the effect of transmission constraints in a context similar to the "what-if" framework of the 2007 Scenario Analysis.[12] While the evaluations are not an introduction to a specific Market Efficiency Transmission Upgrade (METU), also known as an Attachment N project, the results can be used to identify the need for additional targeted studies.[13]

3.4.3.1 Attachment K Study 2008

ISO New England analyzed a series of resource scenarios for a 10-year period from 2009 through 2018 to reflect various alternative system-expansion scenarios focusing on renewable and demand-resource development in the region. [14]

The effect of future resource additions was assessed for the entire 10-year period beginning January 2009 and reflected system conditions, including load levels, transmission constraints, and available resources.[15] In aggregate, four levels of resource additions were hypothesized: 1,200 MW, 2,400 MW, 3,600 MW, and 4,800 MW. These resources were assumed to be located in various places in New England and the neighboring Canadian provinces. The resources represented various technologies, such as onshore wind, offshore wind, biomass, large hydro, CANDU nuclear reactors, and conventional natural-gas-fueled resources.[16] The locations for the new resources were southern New England, southeastern New England, northern Vermont and northern New Hampshire, northern Maine, New Brunswick and the Atlantic provinces (Maritimes), and Québec.

[12] *New England Electricity Scenario Analysis* (August 2, 3007)*;* http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf.

[13] A Market Efficiency Transmission Upgrade is designed primarily to provide a net reduction in total production costs to supply the system load. Attachment N of the OATT describes the requirements for identifying a METU. For further details, see the ISO's OATT, Section II.B, Attachment N, "Procedures for Regional System Plan Upgrades;" http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html.

[14] Market Efficiency Transmission Upgrade is designed primarily to provide a net reduction in total production costs to supply the system load. Attachment N of the OATT describes the requirements for identifying a METU. For further details, see the ISO's OATT, Section II.B, Attachment N, "Procedures for Regional System Plan Upgrades;" http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html.

[15] Historical system performance is discussed in ISO weekly, monthly, and annual market analyses and reports, which are available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/index.html, and in histograms discussed with the PAC, *RSP09 2008 Historical Market Data: Locational Margin Prices Interface MW Flows*, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/jan212009/a_lmp_interface.pdf.

[16] *CANDU* refers to Canada deuterium uranium, a Canadian-designed, pressurized, heavy-water power reactor that uses heavy water (deuterium oxide) as a moderator and coolant and natural uranium for fuel. See http://www.candu.org/candu_reactors.html.

Some key observations from this study are:

- System wide production costs and Load Serving Entity (LSE) electric energy expenses can be affected by the amount of lower-cost resources added.
- Natural gas will remain the dominant fuel for setting marginal electric energy prices.
- Virtually no congestion is apparent within New England under the RSP09 conditions.
- CO_2 and NO_X emissions decrease as more low-emission or zero-emission resources are added but SO_2 emissions are likely to be unaffected.
- The addition of resources that inject a significant amount of electric energy into the market and reduce average clearing prices will diminish the ability of these resources to be self-supporting solely in the New England wholesale electric energy market.
- The addition of resources in portions of southern New England, such as Connecticut, Boston, and southeastern Massachusetts, will not result in congestion. The simulation results show no congestion for the case adding 2,400 MW of NGCC in both Boston and Connecticut. Similarly, a case adding 1,200 MW of wind generation in SEMA/RI also did not result in any congestion. These results also could be viewed as representative of an injection of electric energy through HVDC transmission into these areas.
- The addition of 1,200 MW of resources north of the North–South interface will not create significant congestion on that interface.
- Injections of 1,200 MW of wind energy north of the Orrington–South interface will result in congestion. Increasing the amount of injected energy from additional wind or other resources will exacerbate the congestion.
- Increasing both the Orrington–South and Surowiec–South interfaces by 1,800 MW and increasing the North–South and Maine–New Hampshire interfaces by 1,200 MW would relieve congestion attributable to 3,600 MW of low-energy-cost resources injected into Orrington and an additional 1,200 MW of low-energy-cost resources injected into New Hampshire.

3.4.3.2 New England 2030 Power System Study – Report to the New England Governors

New England has significant potential for developing renewable sources of energy within the region—including substantial inland and offshore wind resources. ISO-NE has identified the potential for up to 12,000 megawatts (MW) of wind resources within New England that, if developed, would represent a major shift in the sources of energy and characteristics of resources operating in the region. Such large-scale penetration of wind resources would affect prices in New England‘s wholesale electricity market and total regional air emissions from other types of generation resources. In addition to significant potential for the development of renewables within New England, major wind power and hydro-electric power development is moving forward in Québec, New Brunswick, and the other Eastern Canadian provinces. Québec and New Brunswick have a long history of electric energy trade with the New England states, and expanding transmission ties to these areas would further expand the sources of renewable energy available to New England.

ISO-NE identified economic and environmental impacts (e.g., wholesale electricity prices and emission levels) for a set of scenario analyses hypothesizing the development of renewables as requested by the New England governors.[17]

This technical analysis was provided to the governors as an economic study performed through the ISO's regional system planning process. The New England States Committee on Electricity (NESCOE), acting on behalf of the governors, submitted the request to the ISO, and the states developed the study assumptions with technical input from ISO-NE. The study was conducted to support the governors' efforts to develop a renewable energy blueprint for the region. The study evaluated the integration of renewable resources, primarily wind, for a single year in the 20-year timeframe—around the year 2030. The study also evaluated the integration of varying levels of demand resources (i.e., energy efficiency and conservation), plug-in electric vehicles (PEVs), energy storage, and other load-modifying resources, which will be enabled by advances in ―smart grid technology. Additionally, the study evaluated possible generator retirements and the repowering of older fossil fuel generation with natural-gas-fired generation.

The New England Regional 2009 System Plan is available at
http://www.iso-ne.com/trans/rsp/2009/rsp09_final.pdf

3.5 Summary

Because planning is a continuous function, the NCSP and other study results are based on the latest information that was available at the time the system analysis was initiated. Each of the ISO/RTOs has their own timelines for completing regional assessments and developing transmission plans. Some of this timing is the result of ISO/RTO tariff or market requirements while the timing of other studies may be driven by human resource constraints at the ISO/RTOs and supporting stakeholders. The JIPC will remain alert to opportunities that can improve interregional planning through better coordination of individual ISO/RTO work activities.

[17] See http://iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/eco_study_report_draft.pdf

4 Summaries of Interregional Studies

The JIPC has coordinated studies of internal system improvements with interregional effects and interconnections between the systems. This section discusses all the interregional studies that have recently been completed or are ongoing.

4.1 Transmission Improvements Having Interregional Impacts

Major system improvements within the ISO/RTOs, as well as those at or near the borders of a region, may affect the interregional system performance. The JIPC has worked to detect such issues by coordinating system models including the development of joint base cases and the representation of contingencies in neighboring systems.

PJM 500 kV Expansion Plan

PJM has added several EHV facilities to its RTEP that were included in the analysis conducted in the Northeast Coordinated System Plan. These major 500 kV, 765 kV, and direct current projects are discussed in Section 3.1 of this report, and are expounded on in further detail in the RTEP. The need for these facilities was reevaluated in 2009 and substantially confirmed. The need for RTEP planned upgrades is reexamined in each annual RTEP process. Models used for interregional analysis were updated to include planned facilities based on the status available at the time of the analysis..

Each of these projects was added to the RTEP primarily to resolve thermal and reactive issues that were identified through PJM's deliverability criteria. These EHV upgrades are needed for the reliability of the PJM network. Extensive analysis of the impact of these lines on the PJM system as well as adjacent systems has been completed and will be reviewed as appropriate.

Queue Projects with Potential Interregional Impacts

Coordination of interregional impacts of projects is a vital part of studies of new generation or transmission projects near the ISO/RTO borders. Thermal, voltage, stability, and short circuit analyses are conducted to ensure reliable plans are developed. ISO-NE, NYISO, and PJM annually update and coordinate short-circuit databases for the current system and representations of the future system. Power flow and stability databases and models are also updated annually.

All projects within an ISO/RTO are reviewed and where potential interregional impacts are recognized, the studies are coordinated with neighboring systems. The scope of work is developed to reflect common databases, base cases, contingencies, and other considerations.

Table 4-1 lists projects in the interconnection queues of ISO NE, NYISO and PJM that potentially have interregional impacts as of October 30, 2009. These projects are in various stages of development and ISO/RTO approval processes. In a few cases, the projects may be close to going into service or are actually in commercial operation.

Table 4–1
Interconnection Queue Projects with Potential Interregional Impacts

Queue No. or ID	Description	Summer Capacity MW	Location	Estimated Commercial Operation
		ISO New England Projects Affecting New York(1)		
104	Gas Turbine	204	Fairfield County, CT	6/1/2010
125	Norwalk Harbor Redevelopment	323	Fairfield County, CT	2/28/2013
161-1	Gas Turbine	197	New Haven County, CT	6/1/2010
161-2	Gas Turbine	215	Middlesex County, CT	6/1/2010
174	Gas Turbine	280	Hampden County, MA	6/1/2012
196	Pumped Storage Upgrade	1,180	Franklin County, MA	5/14/2011-5/17/2015
207	Combined Cycle	452	New Haven County, CT	3/1/2013
222	Combined Cycle	510	New Haven County, CT	6/1/2012
227	Pumped Storage Upgrade	333	Berkshire County, MA	3/31/2011
227	Pumped Storage Upgrade	333	Berkshire County, MA	3/30/2012
271	Two terminal line, DC	N/A	Fairfield County, CT	3/31/2014
281	Wind	85	Rutland County, VT	9/1/2011
292	Biomass	50	Berkshire County, MA	6/1/2014
311	Wind	63	Orleans County, VT	10/1/2012
		New York Projects Affecting New England and PJM (b)		
125	Linden Variable Transformer	300	Staten Island, NY	In Service
N/A	Neptune Project	685	Newbridge, LI	In Service
206	Bergen DC/AC Tie	660	W49 St, NYC	Q2 2011
Various	9 Generation Projects	11,592	Various	Various
Various	8 DC/AC Projects	6,850	Various	Various
Various	23 Wind Projects	2,954	Various	Various
		PJM Projects Affecting New York(c)		
G07_MTX	Neptune Project	685	Firm export to LIPA	In Service
G22_MTX	Linden Variable Transformer	300	Firm export to Con Ed	In Service
066	DC Tie (Bergen)	670	PSE&G to Con Ed	TBD

(a) Based on ISO-NE's October 1, 2009 Queue and several more recent project additions

(b) Based on New York ISO's October, 2009 Queue. One project has 3 phases.

(c) Based on PJM's November 2008 Queue

Status of Planned Interconnections between the ISO/RTOs

This section summarizes planned interconnections between PJM and NYISO and NYISO and ISO-NE.

4.1.3.1 PJM/NYISO

There are several existing transmission ties between PJM and NYISO. Generally these are in two groups: ties between Southeast NY (SENY) and New Jersey, and ties between New York State and Pennsylvania. The SENY ties are the phase shifter controlled ties between Jefferson and Ramapo and several ties that control a wheel of energy into PJM at Waldwick and back out to New York from Hudson to Farragut and from Linden to Goethals. The ties in Western Pennsylvania are high voltage ties from Homer City to Watercure and Stolle Road, ties from East Towanda to Hillside and from Erie East to South Ripley and also several lower voltage ties.

More recently PJM has connected merchant transmission projects that have increased the tie capacity between New Jersey and SENY. The Neptune high voltage direct current project is a 685 MW firm withdrawal from PJM at Sayreville and injected in SENY at Duffy Avenue. A variable frequency transformer project linking Linden, NJ and New York City near Goethals is in service and accounts for 300 MW of firm withdrawal rights. Finally, a planned direct current tie between Bergen, NJ, and 49th Street in NYC has requested 670 MW of firm withdrawal rights from PJM[18].

4.1.3.2 ISO-NE/NYISO

As part of the latest ISO/RTO regional plans, several inter-area transmission ties were successfully planned and placed into service. Major new ties between ISO-NE and neighboring areas include:

- The Northeast Reliability Interconnect Project, consisting of a second transmission tie line between New England and New Brunswick
- A replacement cable upgrading the existing underwater Long Island Cable 1385 transmission tie between Norwalk, Connecticut, and Northport, New York
- The Cross Sound Cable, a merchant transmission tie between East Shore, CT and Shoreham, NY

Several conceptual interconnections between neighboring regions are under various stages of development, including merchant projects connecting Quebec to Fairfield, CT, and Plattsburgh, NY, to New Haven, Vermont. In addition, other developers have suggested projects interconnecting New England with Quebec, New Brunswick, and the other Atlantic Provinces. [19]

Loss-of-Source Analyses

This section summarizes the recent loss-of-source analyses and their interregional impacts, focusing primarily on the PJM and New York interfaces.

4.1.4.1 Summary of Previous Analyses

Loss of Source (LOS) studies are important examples of interregional planning that impacts the three ISO/RTOs. These studies simulate the normal planning criteria contingency-loss of generating units and

[18] Updates to in-service status of merchant transmission projects can be found at http://pjm.com/planning/merchant-transmission.aspx.

[19] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2007/dec182007/index.html

HVDC interconnections to assess interregional operating limits, and evaluate opportunities to increase these limits. In New England, the transfer limits from LOS contingencies are the higher of 1,200 MW or the more restrictive of PJM's and NYISO's internal limitations. Like other system contingencies, the LOS limits prevent adverse impacts from contingencies internal to New England on neighboring systems.[20] During many periods, the 1,200 MW limit was binding and it was recognized there would be a number of potential benefits of having a higher loss-of-source limit. They include:

- The ability to import more power from Canada over the HVDC Phase II interconnection
- Fewer reductions in dispatch of larger nuclear units/stations and the Mystic units #8 and #9
- Reliable interconnections of large new generating units or new transmission tie lines to Canada
- Lower energy prices in New England and neighboring regions

Studies that examined the possibility of increasing the NYISO and PJM limits showed that local area improvements, such as the addition of series reactors on the New York to New England tie lines, are not feasible ways to increase the LOS limit[21]. However, long-term system improvements planned in New York and PJM were assessed, and showed some benefits. These included:

- New generating resources in the Hudson Valley
- Improvements in PJM 500 kV and 765 kV facilities that will increase the ability to transfer power from the west to the east [22]
- New merchant transmission tie lines between New York and PJM
- New ties between New York and New England
- Other transmission improvements in New York, New England, and PJM

While this assessment shows a potential increase in the permissible loss-of-source limit for New England above 1,200 MW up to a 1,500 MW to 1,600 MW range due to contingency restrictions within New York, constraints in PJM will likely limit the LOS contingencies to 1,400 MW to 1,500 MW.[23]

The possibility of additional system improvements in New York, PJM, and New England were then explored to determine whether an increase of the LOS limit above the 1,400 MW level is possible. After discussions of preliminary results and receipt of input from the IPSAC, the JIPC decided to conduct more detailed studies of the New York North Country, Vermont, and a new upgrade interconnecting the two areas.

These studies show that voltage limitations would restrict New York's Central East interface to about 2,800 MW. Prefeasibility studies of replacing the 115kV tie between Plattsburgh and Vermont (PV-20) with a 230kV tie showed that both the Central East limit and the New England LOS limit could be increased.

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[21] For more information, see the report presented to IPSAC in December 2007, available at http://www.interiso.com/public/meeting/20071214/20071214_Loss_of_Source_12-4-07.pdf

[22] The analysis included consideration of major transmission improvements currently planned, including TRAIL, PATH and other 500 kV improvements in PJM.

[23]These results were presented to the IPSAC in December 2007. A report on the subject is available at: http://www.interiso.com/public/meeting/20071214/20071214_Loss_of_Source_12-4-07.pdf

Plattsburgh – Vermont Upgrade

To build upon previous results, a prefeasibility study has been completed that considers the addition of a 230kV tie between Plattsburgh and Vermont but retains the existing Plattsburgh Vermont (PV-20) 115 kV interconnection. This new prefeasibility study was motivated by the following factors:

- Increased interconnection of wind projects in northern New York may produce transmission constraints out of the North Country
- Load growth coupled with transmission or generation facilities out of service raises reliability issues in both New England and New York
- Vermont is developing a new 10 year plan and may require a new transmission source to the area
- New York's Central East interface, of which the existing PV20 tie is a member, can limit the transfer of power across the New York system,
- Previous New England Loss of Source (LOS) studies showed that potential increases in transfer limits can be achieved with upgrades in the northern Vermont-New York area.

Approximately 600 MW to 900 MW of wind development is in various stages of development in the North Country of New York. Resources in that area may become constrained without the addition of transmission improvements that provide higher transfer capability out of the area.

The most recent Vermont ten-year plan for the year 2019 is currently under development. Critical assumptions in the needs analysis include whether Vermont Yankee would be relicensed to continue operating beyond 2012, and whether the Highgate purchase, which ends in 2016, would be continued. Preliminary results discussed with New England stakeholders considered several different preliminary solutions to low voltage issues within Vermont. These included reactive reinforcements, new Canadian imports, and a 230 kV tie between Plattsburgh and Vermont. A full report is expected to be issued in 2010.

The prefeasibility NCSP09 Plattsburgh – Vermont Tie study is intended to be a parallel effort, complementing other analyses done in the North Country and Vermont areas, with a greater focus on interregional impacts and cross-border issues. It is not a firm plan; rather, it is intended as a proactive effort to address reliability needs and ascertain any potential benefits in two different ISO/RTO regions. Additional analysis would be needed before considering an additional tie as a viable option for improving the New York and New England systems. Some results were discussed in the 2008 NCSP, and the results here build on that prior work.

4.1.5.1 Upgrades Studied and Study Method

The prefeasibility study considered the following alternatives:

- Building a new 230 kV transmission interconnection from Plattsburgh, NY to New Haven, VT
- Building a new 230 kV transmission interconnection from Plattsburgh, NY to Granite, VT

These alternatives include two 350 MVA 345 kV/115 kV step down transformers at Essex, Vermont and a 500 MVA ±60 degree phase angle regulator at Sandbar, Vermont. The base case for the study was set at 2008 estimates of 2013 and 2018 load levels and reflected relevant upgrades in New York, New England, and PJM. Each case reflected interface constrains in the three ISO/RTO regions. Comprehensive N-1 contingency analysis was conducted, as well as N-1-1 for selected critical system elements. For each scenario, the range of valid operation of the PAR was determined.

4.1.5.2 Study Results

Analysis of the 2013 system revealed that, for select N-1-1 conditions, a new tie terminating at Granite did not have a secure operational point. This option was then discarded for 2018 analysis, and only a tie terminating at New Haven was considered. For both 2013 and 2018 cases, a new tie to New Haven had an operational range allowing for 400 MW of transfer to New England and 300 MW of transfer to New York, given some assumed upgrades, with some N-1-1 conditions curtailing this range somewhat[24]. The transfer limit was increased by holding the existing PV20 at 0 MW of transfer, suggesting that a new tie would function better as the sole means of pre-contingency power transfers in the area. Although the new tie improved system performance, it did not resolve all voltage issues in Vermont, suggesting that some of the upgrades being identified in other studies would still be needed were a new tie to be constructed.

The studies demonstrated the benefits of separating the Moses-Willis 230 kV lines from their common structures, with or without the addition of a new tie from Plattsburgh to Vermont. The studies also showed the benefits of closing the Plattsburgh 230kV buses for the addition of a new tie to New England.

4.2 Reliability Analysis of the NYISO/PJM Area

NCSP09 reliability analysis focused on the PJM/NYISO interface located between Southeast NY (SENY) and Northern Public Service, New Jersey. Specifically:

- PJM - Public Service-North and Rockland Electric
- NYISO - Area G, H, I, J and K (Hudson Valley, Con Ed and LIPA)

The analysis examined the combined areas under standard PJM reliability testing procedures. This included reliability screening of NERC contingency categories A, B, and C, a generation deliverability screen and a load deliverability screen. No significant reliability issues were uncovered during this testing. The reliability analysis was conducted using a 2013 study year case originating from the 2008 series Eastern Reliability Assessment Group case. The PJM model originated from the 2009 RTEP reference case and included all currently planned PJM RTEP facilities and interconnection projects. The NY case originated from the 2009 RNA system model for the year 2013. The following PJM backbone expansions were included:

- Susquehanna – Roseland 500kV Circuit
- MAPP (Possum Point – Burches Hill – Chalk Point – Calvert Cliffs 500 kV AC)
- MAPP (Calvert Cliffs - Indian River 500 kV DC)
- Branchburg – Roseland – Hudson 500 kV
- PATH (Amos – Kemptown 765 kV)
- TRAIL (502 Junction – Loudoun 500 kV)

The following NYISO system improvements were included:

- M29 (Sprainbrook – Sherman Creek 345 kV)

The following merchant transmission projects between PJM and NYISO were included:

[24] A detailed appendix describing these results is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2009/dec162009/vt-ny_appendix.pdf (New England CEII clearance required)

- Neptune project (PJM Queue G07_MTX) modeled at 685 MW exporting to LIPA according to its firm withdrawal rights
- VFT (PJM Queue G22_MTX) modeled at 330 MW exporting to ConEd according to its firm withdrawal rights
- Hudson Transmission Partners (PJM Queue O66) modeled at 670 MW exporting to ConEd's 49th Street Substation

Additionally, the Long Island to New England cross sound cable was modeled consistent with the 2009 RNA.

The analysis included a comprehensive testing of all N-1-1 contingencies at 230 kV and above. All facilities at voltages above 100 kV were monitored.

The PJM generation delivery procedure examined PJM generation queue interconnection projects under study to identify any cross-border issues that may be caused by these interconnections. No cross-border impacts were evident. The analysis examined all local generation at maximum output under 50% probability summer peak load conditions and under NERC category A, B and common cause type C contingencies.

The PJM load deliverability procedure ensures that the transmission system is capable of supporting emergency imports to the local study area under a 90/10 summer peak and with severe generation unavailability. The aim of this test is to determine if the transmission system can support the loads' use of the planned broader generation system reserves even when the local area experiences a low probability generation event. This test if uniformly applied to a centrally planned generation and transmission system promotes the elimination of load pockets. The conclusion from this testing is that the combined study areas satisfy the load deliverability test.

The load deliverability procedure is comprised of a reliability test with a zonal reliability model, such as MARS or PRISM. This test is used to find the Capacity Emergency Transfer Objective (CETO) for the area under study. A separate power flow analysis is used to determine the import Capacity Emergency Transfer Limit (CETL). These two values are compared, and if the CETL is equal to or greater than the CETO, the test is passed.

The test results for two scenarios of local area testing were as follows:

- For load deliverability testing of combined PSN + RECO + SENY areas
  - The reliability transfer objective is 9180 MW
  - The transfer limit into the area exceeds this level
- The reliability transfer objective for the smaller PSN + RECO + NYC area
  - The reliability transfer objective is 8340 MW
  - The transfer limit into the area exceeds this level

4.3 Market Efficiency Analysis

Market efficiency analysis can be used to produce various metrics, such as system wide production costs, fuel usage, load serving entity energy expenses, locational marginal prices, and system emissions. Among other applications, these studies can be used to identify transmission constraints and the effects of transmission improvements in relieving transmission constraints.

The Interregional Electric Market Model (IREMM) is a simulation tool that ISO-NE has used in past production cost analyses for developing hourly chronological system-production costs, as well as other metrics. IREMM is a high level simplified production cost model with a gross representation of resource dispatch and commitment. Loads are aggregated into subareas (a.k.a. bubbles) and transmission constraints are represented as transportation limits on major interfaces. IREMM offers advantages of easily understanding system performance and "seeing the forest for the trees" as a high level screening analysis. The high level model database coordinates and builds upon common databases and can be used to improve external representations when using more detailed production cost programs. Through the years it has benchmarked well with other production cost programs.

Detailed production cost programs (such as PROMOD, Gridview, MAPS) have a full representation of unit dispatch and commitment and are aligned with full load flow system representations. Because transmission constraints are explicitly modeled and not limited to major interfaces, these types of production programs provide a detailed understanding of system performance, such as reliability must run situations. Development of detailed production program data bases requires considerable effort and care.

Fully coordinated production cost data bases were established for the NYISO, PJM, ISO-NE, and neighboring systems for both IREMM and detailed production cost programs. The JIPC conducted studies of the 2013 system to identify transmission interfaces that may limit economical interregional transfers and to determine the effects of relieving the identified transmission constraints.

Market Efficiency Analysis of the NYISO/PJM Area

The market efficiency analysis scope of work complements the reliability analysis discussed in Section 4.2.A detailed nodal production cost model of the combined NY, NE and PJM areas was developed using PROMOD. The goals of this analysis were twofold:

- Developing an initial detailed nodal market representation of the combined areas, and to perform a 2013 annual hourly simulation
- Examining the potential economic benefits of any reliability upgrades that could evolve from the reliability study discussed in Section 4.2.

The first goal was completed and the second goal was unneeded since no reliability upgrades were identified.

The data modeling inputs for the combined area modeling was based on the publically available Ventyx database. The analysis used load and capacity assumptions consistent with each region's forecasts. System topology was consistent with the reliability analysis. In addition, the assumptions for fuel prices, emission allowance prices, and interregional interchange were as follows:

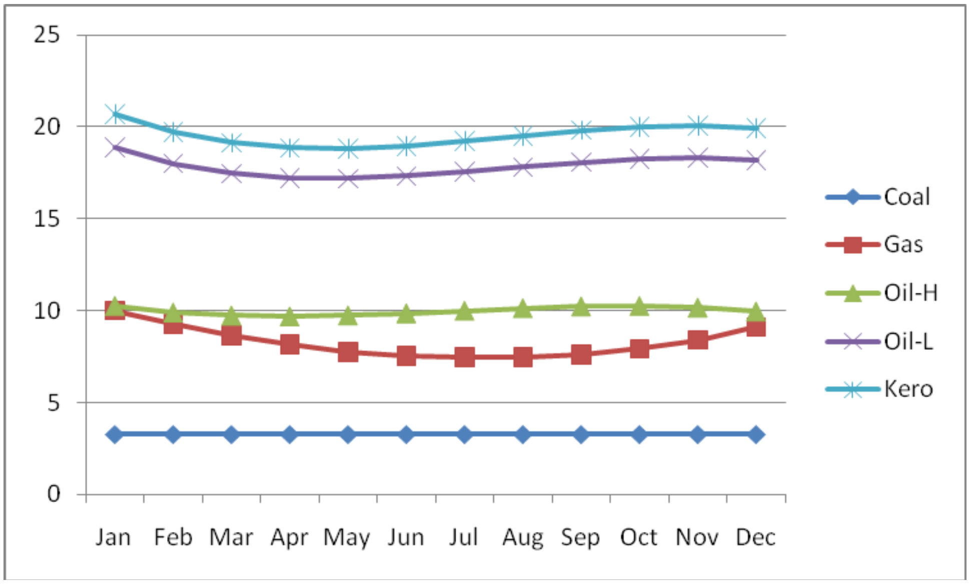

Figure 4-1: NYISO/PJM 2013 Average RTO Fuel Price Assumptions

Year	SO_2	NOx Annual	NOx Seasonal	CO_2
2013	$725	$998	$751	$10

Table 4-1: NYISO/PJM 2013 Emissions Costs ($/ton)

Also, the following key assumptions were assumed:

- Interchange modeled using a $10/$5 commitment/dispatch hurdle rate[25]Public Service / ConEd Wheel modeled as 1000 MW total into Waldwick and 1000 MW total out to Hudson and Linden
- Initial setting of the Ramapo PAR set to 900 MW into NYISO

Simulation results produced the projected average hourly nodal Locational Marginal Prices (LMP) by zone and a list of the most significant constraints causing price separations. Total system congestion was about $1.2 billion across the northeast, with the largest LMP spreads between:

- Western PJM to Eastern PJM
- Northern/Western NY to South Eastern/Long Island NY
- NJ/NY PAR facilities

Examination of these results led to the conclusion that they are consistent with current market conditions. It was also concluded that the complex operation of the controlled devices controlling power flows along the eastern PJM and Southeast NY border should be further investigated to develop possible model enhancements used in future analyses. The following are the primary results from the market efficiency modeling.

[25] A Hurdle Rate is the minimum amount of return that required before an investment is made by an entity

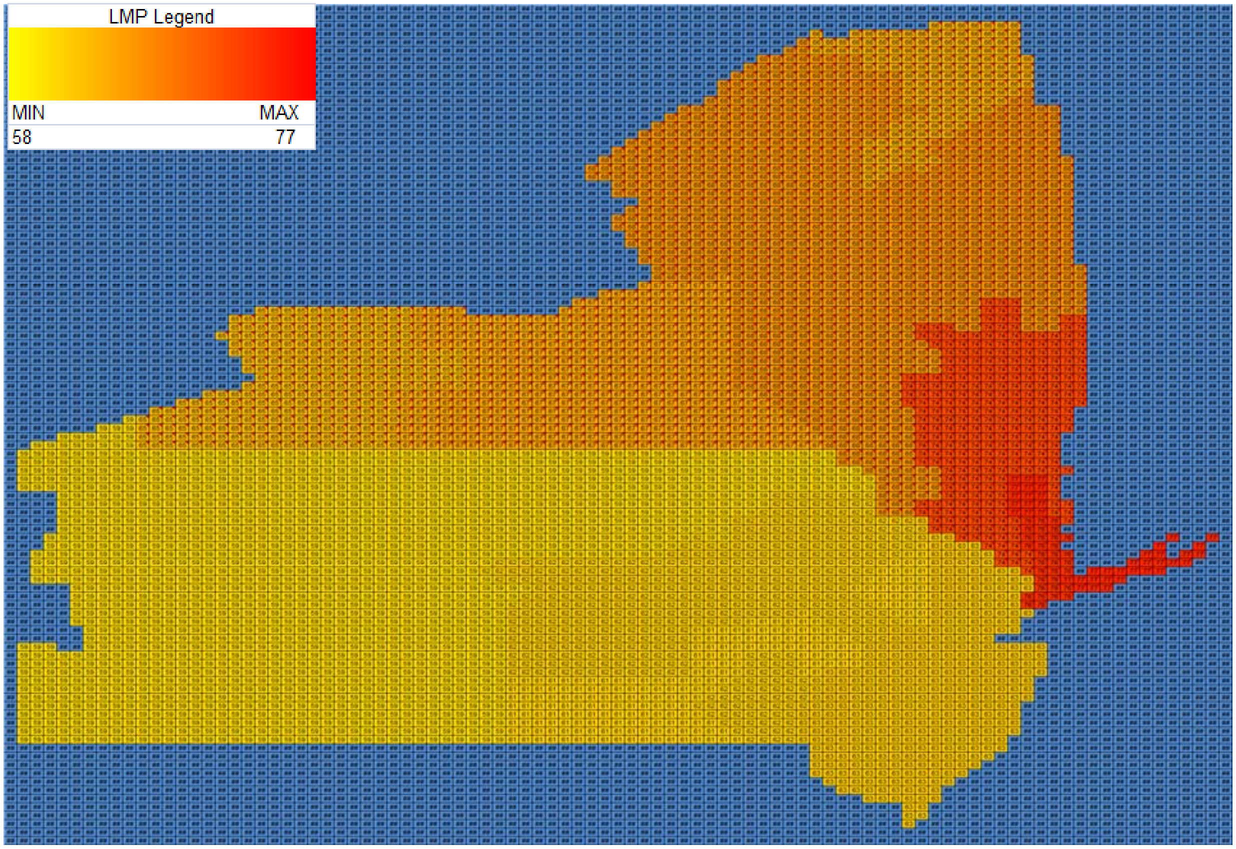

Figure 4-2: NYISO/PJM2013 Market Efficiency Study LMP Results

Constraint	Area	Frequency(Hours)	Market Congestion Rank
Leeds-Pltvlley CTG	NYISO	3380	1
Interface AP - South	PJM	2121	2
Interface PJM - Central	PJM	5189	3
Waldwick PARs	PJM-NYISO	8719	4
Ramapo PARs	PJM-NYISO	7444	5
Farragut PARs	PJM-NYISO	8736	6
Altoona-Brrck N3	PJM	1171	7
Cloverdale-Lexington	PJM	544	8
Clover 500/230 kV Tx CTG	PJM	1017	9
Gothls S - Gowanuss CTG	NYISO	532	10
Interface Line: 966 Penelec-NYCent1	PJM-NYISO	5042	11
Elrama-Mitchel CTG	PJM	1879	12
Linden-Goethals PAR	PJM-NYISO	8721	13
Interface Line: 669 CE Group	NYISO	464	14
Linwood-Chichester2	PJM	282	15

Table 4-2: NYISO/PJM2013 Market Efficiency Study Interface Congestion

Market Efficiency Analysis of the NYISO/ISO-NE Area

The goal of this analysis is to identify where major interfaces are constraining interregional transfers by modeling the PJM "Classic", NYISO, and ISO-NE systems with suitable representations of neighboring areas. The scope of work also calls for relaxing the limits of various combinations of the constrained interfaces in postulated increments of 500 MW to 1000 MW. The study will produce various metrics, including production cost, load serving entity energy expenses, environmental emissions, and locational marginal prices of load bubble areas.

A coordinated IREMM production cost model was developed based on assumptions that were reviewed with the IPSAC as follows:

- EIA 860 2008 data and heat rates for some units from 1995 data
- FERC FIPS Codes
- NERC GADS
- ISO/RTO information/databases
- Resource Expansions, Retirements, and Replacements reflect ISO/RTO expansion plans based on capacity markets and other "firm" plans for generation expansion
- Dispatch costs are consistent with EIA database assumptions, such as fuel prices and dispatch costs
- Emission rates and cost adders are presented and include $10/ton for carbon emissions
- Transmission Interface Limits are the normal limits used for major interfaces and connect "load bubbles" similar to resource adequacy studies (MARS program)
- Load levels and profiles are based on 50/50 forecasts developed in 2009, the ISO-NE RSP09 ten-year forecast, the NYISO 2009 Load & Capacity Data Report , and the PJM 2009 forecast report

The initial results will focus on the NYISO/ISO-NE area and are expected to be presented to the IPSAC during 2010. The IREMM results will be compared to other production cost programs to demonstrate general consistency of results. IREMM analysis will then be expanded to consider constrained PJM interfaces. Follow-up analyses will then be conducted using a more detailed production cost program, such as PROMOD.

5 Additional Coordinated Planning Activities and Issues

ISO New England, NYISO, and PJM participate in the ISO/RTO Council (IRC), an association of the North American Independent System Operators and Regional Transmission Organizations. ISO-NE and NYISO are actively participating in NPCC interregional planning activities along with the Canadian Members of NPCC and the technical participation of PJM. All of the ISO/RTOS are participating in a number of other activities designed to improve interregional coordination with other ISOs and RTOs. Several major interregional activities that are supported by the three ISO/RTOs are now discussed.

5.1 Coordination of Studies and Databases

The development and updating of common databases and their interregional coordination is required for interregional planning studies. The starting point is the development and/or updating of each ISO/RTO's transmission databases and models, which then becomes inputs to interregional planning processes. The key inputs are:

- Load forecast updates
- Resource requirements/reserve margin
- Base case resources: supply, transmission and demand response
- Models: Load flow (PSS/E), resource adequacy (MARS), production cost (MAPS, PROMOD, GridView and IREMM), stability (PSS/E), short circuit (ASPEN and PTI)

Regional studies that are typically conducted include:

- Resource adequacy
- Reliability assessments
- Economic (production cost or congestion) analysis
- Interconnection studies: generation and merchant transmission
- Requests for transmission service
- Special studies, e.g. scenario analysis, wind integration, environmental and fuel

Many interregional updates of databases/studies are done annually or periodically as needed. National updates include FERC Form 715, EIA Form 411 and DOE congestion studies. NERC updates include ERAG, GADS and TADS. NPCC/RFC updates are NERC databases coordinated through NERC regional entities. The Northeastern Protocol uses the updates for the other entities and customizes them as needed for Northeast regional studies.

Database development, updating and studies are an ongoing process and this is coordinated across regions In this process the regions share lessons learned, best practices, and advances in technology and software.

5.2 Northeast Power Coordinating Council

The Northeast Power Coordinating Council is one of eight regional entities responsible for enhancing and promoting the reliable and efficient operation of the interconnected bulk power system. NPCC's geographic area spans the northeastern North American continent and includes New York, the six New England states, Ontario, Québec, and the Maritime Provinces in Canada. Pursuant to separate agreements with its membership and NERC and by a Memorandum of Understanding (MOU) with the applicable Canadian authorities, the NPCC provides the following activities and services to its geographic area:

- Statutory activities—develop regional reliability standards; assess compliance with and enforce these standards; coordinate system planning, design, and operation; and assess reliability
- Non-statutory criteria services—establish regionally specific criteria and monitor and enforce compliance with these criteria

ISO -NE and NYISO are committed to the goals of the NPCC and to plan and operate their systems in full compliance with NPCC criteria, standards, guidelines, and procedures. They are also active participants in NPCC interregional studies and planning initiatives with the full technical participation by PJM.

Coordinated Planning

NPCC's Task Force on Coordination of Planning (TFCP) reviews the adequacy of the NPCC member systems to supply load, accounting for forecasted demand and planned resources. The reviews are accomplished in accordance with the NPCC *Guidelines for Area Review of Resource Adequacy* (Document B-08) on the basis of the schedule set forth in the NPCC Reliability Assessment Program.[26] The TFCP also reviews the compliance of future plans with the basic criteria consistent with the *Guideline for NPCC Area Transmission Reviews* (Document B-4).[27] All studies are well coordinated across neighboring area boundaries and include the development of common databases that can serve as the basis for internal studies by the ISO.

In coordination with NERC, NPCC also gathers data and assesses the resource adequacy of its five areas.[28] The results of these studies show that among the five NPCC areas, the Maritimes and Québec are winter-peaking systems. Ontario historically experienced its annual peak demand in the winter but recently has become a summer-peaking system. The New York and New England areas continue to be summer-peaking systems. Owing to the mix of winter- and summer-peaking balancing authority areas, the wider NPCC region has reserves to share among the areas during the seasonal peaks. This seasonal diversity also changes the overall summer and winter system flows of electric power and energy.

Resource Adequacy Analysis (CP-8)

Under the CP-8 Working Group, NPCC coordinates resource adequacy studies of its ISO/RTO areas and provides technical support that is necessary for the evaluation of the resource adequacy of the NPCC region. In 2009, NPCC conducted summer and winter multi-area probabilistic reliability assessments of the NPCC region and other neighboring systems including PJM. The studies evaluated the Loss of Load Expectation (LOLE) of the interconnected system for both the summer and winter periods of 2009. The GE MARS program was used for evaluating a base case and a severe case. Transmission constraints within each area and between areas were also modeled in these analyses. The results showed that all regions satisfy the resource adequacy criteria of meeting a loss of load expectation no greater than one day in ten years.

In 2010, NPCC will conduct an interregional long range adequacy overview to evaluate the near-term seasonal (2010 summer and 2010/11 winter) and long-range (2010-2014) adequacy of the NPCC areas

[26] Guidelines for Area Review of Resource Adequacy, NPCC Document B-08 (New York, NPCC Inc., November 29, 2005); http://www.npcc.org/documents/regStandards/Guide.aspx

[27] Guidelines for NPCC Area Transmission Reviews, NPCC Document B-04 (New York, NPCC Inc., March 5, 2008); http://www.npcc.org/documents/regStandards/Guide.aspx

[28] The NERC Reliability Assessment Subcommittee (RAS) publishes several reports; see http://www.nerc.com/page.php?cid=4|61.

through multi-area probabilistic assessments, which will reflect neighboring regional plans proposed to meet their respective resource adequacy planning criteria. In addition, NPCC will perform an interconnection assistance reliability benefit study to estimate the amount of interconnection benefits available to the NPCC areas for the time period from 2011 to 2015 under different system conditions. The study is scheduled to be completed by December 31, 2010.

NPCC Overall Transmission Assessment

In accordance with NPCC Reliability Assessment Program, the Task Force on System Studies (TFSS) is mandated to perform an Overall Transmission Assessment (OTA) of the reliability of the planned NPCC bulk power system every three years. This study assesses the performance of the NPCC system by evaluating the dynamic and steady state performance of the entire NPCC system for various design and extreme contingencies under conditions projected for 2013. The study examines the system from a broad regional and inter-regional perspective by building upon and supplementing the transmission reviews conducted annually by each of the NPCC areas. Scheduled for completion for final NPCC approval during 2010, the OTA study also builds upon and is coordinated with other ISO/RTO studies. The OTA is being conducted by the members of NPCC members and neighboring regions, including PJM.

The draft OTA has been recommended for NPCC approval by TFSS. The study considered planned 500 kV and 765 kV facilities proposed within PJM by demonstrating acceptable system performance. The results showed reliable operation, including normal power flows and response to critical normal and extreme contingencies in the NPCC and PJM systems. Simultaneous transfer limit studies were also conducted to determine the limits for key transmission interfaces at and near the border of the RFC and New York Control Area (NYCA). The interfaces were tested in a manner similar to the load/generator deliverability testing procedures of each ISO/RTO.

The analysis performed for the OTA shows:

- The NPCC system projected for 2013 remained stable with no inter-Area and interregional impacts for all tested design contingencies originating within and outside the NPCC region
- The NPCC system projected for 2013 remained stable with no inter-Area and interregional impacts for all but one of the tested extreme contingencies originating within and outside the NPCC region. A damped response for the problematic contingency was observed when key interface flows were reduced to levels that are more appropriate for extreme contingency testing.
- The NPCC system projected for 2013 exhibited an acceptably stable and damped dynamic response for all simulated beyond normal criteria contingencies
- The proposed large future system developments in the adjacent RFC region did not negatively impact the dynamic performance of the NPCC system projected for 2013 for all tested contingencies originating within and outside the NPCC region. The developments included the following EHV transmission lines in the PJM area planned to be in service by the study years:
    - Amos – Welton Springs – Kemptown 765 kV Circuit
    - Susquehanna – Lackawana – Jefferson – Roseland 500kV Circuit (includes looping the
    - Branchburg – Ramapo 500 kV line into Jefferson)
    - 502 Junction – Mt. Storm – Meadowbrook – Loudoun 500kV Circuit (TRAIL)
    - Roseland – Hudson 500 kV Circuit
- In general the results are consistent with past OTAs and demonstrate the robustness of the NPCC system.

RFC 2014 Long-Term Assessment of Transmission System Performance

Reliability*First* Corporation (RFC) long-term transmission assessment satisfies its responsibility to comply with NERC criteria TPL-005, which calls for RFC to perform a long-term transmission assessment of its footprint area with an emphasis on examining potential transmission constraints. RFC complies with this mandate by examining work already performed according to the planning processes of PJM, MISO, MRO, SERC, and VACAR and studies performed by the Eastern Reliability Assessment Group (ERAG). In addition, RFC performs its own long term transmission assessment in conjunction with affected transmission owners.

The RFC long-term assessment was based on the most recent ERAG model of the 2014 summer peak conditions and an appropriate market dispatch. This base case was examined under NERC criteria category A and B conditions. Five first contingency issues were noted in PJM and all are under consideration for reliability upgrades pursuant to PJM's internal RTEP process.

The case was then stressed under thirty different transfer scenarios. Typically these conditions could represent severe system conditions that may be experienced under adverse weather, generation deficiencies, transmission configuration or other emergency type situations. These tests go beyond the normal RTO NERC criteria testing that would require upgrades for reliability. RTO internal planning processes establish all needed system upgrades for full compliance with NERC criteria.

The RFC transfer testing examined the thermal and voltage performance of the systems in the RFC footprint under many combinations of high non-simultaneous and simultaneous transfers. No new reliability issues were uncovered through this analysis. Results were consistent with regional internal planning. This analysis demonstrated the robustness of the system. One result reported in the RFC review related information from an RFC/NPCC study group analysis of 2014 transfers between the regions. This analysis indicated that the Lake Michigan to Ontario phase angle regulators (PARs) are instrumental to the optimization of the interface between the two NERC regions. Transfer results showed that, for all transfers, the limits after double contingencies and PAR adjustments exceed the initial first contingency limits. The reported First Contingency Incremental Transfer Capabilities (FCITC) and double contingency limits are show in the following table.

Transfer Scenario	FCITC (MW)	Representative Double Contingency Transfer Limit
NPCC - PJM	3200	4000
NPCC - MISO	3300	3400
PJM - NPCC	4800	5600
MISO - NPCC	300	1900

5.3 IRC Activities

Created in April 2003, the ISO/RTO Council is an industry group consisting of the 10 functioning ISOs and RTOs in North America. These ISOs and RTOs serve two-thirds of the electricity customers in the United States and more than 50% of Canada's population. The IRC works collaboratively to develop effective processes, tools, and standard methods for improving competitive electricity markets across North America. In fulfilling this mission, the IRC balances reliability considerations with market practices that encourage the addition of needed resources. As a result, each ISO/RTO manages efficient, robust markets that provide competitive and reliable electricity service, consistent with its individual market and reliability criteria.

While the IRC members have different authorities, they have many planning responsibilities in common because of their similar missions to independently and fairly administer an open, transparent planning process consistent with established FERC policy. As part of the ISO/RTO authorization to operate, each ISO/RTO has led a planning effort among its participants through an open stakeholder process. In addition, with the implementation of Order No. 890, ISOs/RTOs have upgraded their planning processes to meet FERC's objectives.[29] Specifically, the transmission planning process must provide for coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. This ensures a level playing field for infrastructure development driven efficiently by competition and meeting all reliability requirements.

The IRC has coordinated filings with FERC on many issues, such as those concerning the administration of the ISO's Generator Interconnection Queue and other technical issues. For example, the IRC has identified issues and is acting to address the challenges of integrating demand resources and wind generation and, through its representatives, is leveraging the efforts of NERC's Integrating Variable Generation Task Force (see Section 8.1.2). The IRC has representation on other NERC task forces and committees.

5.4 NERC ERAG

In 2006, the six regional managers of the Eastern Interconnection developed and executed an agreement that governs the interregional study development in the Eastern Interconnection. That agreement establishes an Eastern Interconnection Reliability Assessment Group Management Committee (ERAG MC) that oversees interregional study activities. This responsibility was expanded to include all base case development activities by the Multiregional Modeling Working Group (MMWG).

There are three inter-regional study forums in the ERAG – RFC-NPCC, RFC-SERC East and RFC-MRO-SPP-SERC West. The activities of these three forums are now overseen by the ERAG MC. The RFC-NPCC forum includes the RFC-NPCC Steering Committee (RNSC) and the RFC-NPCC Operating Studies Working Group (RNWG). The RNSC reviews and approves the RFC-NPCC seasonal reports and submits them for final review and suggestions by the ERAG MC before final release.

Under the direction of the RNSC, the RNWG conducted an appraisal of the interregional transmission system performance among the RFC-NPCC study areas for the conditions expected in the 2009 summer period. This study is performed in support of TPL-005-0 and satisfies TPL-005-0 Requirement R1.

This effort models transfers between areas that reflect the changing transmission market and the Regional Reliability Organization affiliations of transmission owners. If the PJM market is the source or the sink for the transfer, the designation will be PJM. The term "RFC-MISO" refers to the Midwest ISO systems that are in RFC.

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[29] *Preventing Undue Discrimination and Preference in Transmission Service, Final Rule*, 18 CFR Parts 35 and 37, Order No. 890 (Docket Nos. RM05-17-000 and RM05-25-000) (Washington, DC: FERC, February 16, 2007); http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf. Also see *Open Access Transmission Tariff Reform*, *Order No. 890 Final Rule* (Washington, DC: FERC, 2007); http://www.ferc.gov/industries/electric/indus-act/oatt-reform/sum-compl-filing.asp. While not FERC jurisdictional, the Canadian ISO/RTO processes are intended to comply with Order 890 requirements.

The purpose of this study is to provide:

- An analysis of First Contingency Incremental Transfer Capabilities (FCITC) and corresponding First Contingency Total Transfer Capabilities (FCTTC) for selected transfers that may occur simultaneously among, or through, the RFC and NPCC regions.
- FCITC and the corresponding FCTTC, as defined in Appendix D, for non-simultaneous emergency transfers between RFC-MISO and NPCC, and between PJM and NPCC. While the PAR transformers that separate the Michigan and Ontario systems were used to increase flows appropriately for the simulated transfers, no attempts have been made to optimize transfers between regions by changing dispatches or any PAR settings.
- Appraisals for the RFC-MISO, PJM, and NPCC study areas for the current study season.

The FCITC and FCTTC values reported in this study are based on simulated system operation. Other operational changes expected to occur during this summer are discussed in the individual regional assessments.

The reported FCITC and FCTTC values are based on the prediction of many factors that actually change during the daily operation of the power system. Among these variable factors are:

- load forecasts and generation availability
- geographic distribution of load and generation
- transmission system configuration
- simultaneous inter-system power transfers
- operation based on regional requirements to respect additional contingencies
- control settings of phase angle regulators

An appraisal of the interregional system performance among the RFC-SERC East region is presented in the companion RFC-SERC East Steering Committee Report: RFC-SERC East 2009 Summer Interregional Transmission System Reliability Assessment dated May 2009.

5.5 Available Transfer Capability vs. RFC - NPCC Seasonal Study Incremental Transfer Capability (ITC)

FERC Order 889 mandated that each US transmission provider calculate Available Transfer Capability (ATC) and post such values to an Open Access Same Time Information System (OASIS). FERC deferred the development of ATC methodology to NERC, which has developed a series of technical references, including *Available Transfer Capability Definitions and Determination*[30], which describes the methodology of calculating ATC/TTC and the application of Transmission Reliability Margin (TRM) and the Capacity Benefit Margin (CBM). The underlying concepts for both the ATC methodology and the methodology used to perform RFC-NPCC seasonal studies are found in the *Transmission Transfer Capability*[31] document published by NERC in 1995. These concepts include the First Contingency Incremental Transfer Capability (FCITC) and First Contingency Total Transfer Capability (FCTTC).

Thus, the methodology of ATC as calculated by transmission providers and the regional transfer capabilities developed by RFC-NPCC are similar. Both calculate incremental and total transfer capabilities

[30] Available online at http://www.nerc.com/docs/docs/pubs/atcfinal.pdf

[31] Available online at http://www.nerc.com/docs/docs/pubs/TransmissionTransferCapability_May1995.pdf

on a first contingency basis, with the magnitude of transfer capability based on increasing transfer levels until transmission limits are incurred.

The following sections outline, in detail, the difference between the ATC calculations and the RFC-NPCC study methodology.

ATC/RFC-NPCC methodology differences

5.5.1.1 Scope

ATC is calculated by transmission providers, which generally corresponds to the individual Balancing Authority areas, whereas RFC-NPCC studies are calculated at the NERC regional and large market level. RFC-NPCC studies have changed in recent seasons to address transfer limits from a market-based generation perspective rather than from the traditional NERC regional level. The studies now model transfers involving the PJM market, the IESO and NYISO markets in NPCC, and the RFC-MISO area that includes the eastern portion of the Midwest ISO market plus other former ECAR companies.

5.5.1.2 Coordination

ATC is calculated by transmission providers using system representations and procedures they deem appropriate. Transfer capacity is calculated using the most up-to-date system representation and procedures established by RFC and NPCC. The case used is derived from the ERAG MMWG case, including fine tuning conducted by the ERAG study forum working groups.

5.5.1.3 Margins

ATC determination uses margins (TRM/CBM)[32] to provide for variation in system operating conditions, whereas the RFC-NPCC study reports FCITC calculations without applying a margin.

5.5.1.4 Tie Capacity

ATC between adjacent control areas is limited by scheduling limits based on the tie capacity between Balancing Authorities, whereas the RFC-NPCC study reports inter-regional network transfer capabilities regardless of scheduling limits between individual Balancing Authorities.

5.5.1.5 Timeframe

ATC is calculated hourly, daily, weekly, and monthly, whereas the RFC-NPCC study is conducted semi-annually based on a snapshot of anticipated conditions.

[32] TRM or Transmission Reserve Margin is an amount of transmission capability that is set aside to account for uncertainties in system conditions inherent in transmission transfer capability determinations such as load forecast uncertainty. CBM or Capacity Benefit Margin is an amount of transmission capability that is set aside for the benefit of Load Serving Entities to ensure access to generation from interconnected systems for to support system reliability.

5.5.1.6 Publishing

ATC is posted to an OASIS for use by the commercial markets, whereas the RFC-NPCC study is published for use as an interregional reliability assessment

ATC Results

The following observations and conclusions are made based on the results of the 2009 summer assessment.

RFC-MISO and PJM market dispatches were modeled for the 2009 summer study base case. Therefore, any comparison of the transfer limits reported in this assessment with those from previous studies needs to acknowledge differences between the current market-based topology used in this study and the traditional regional dispatches used in past years.

If the RFC-MISO market is the source or the sink for the transfer, the dispatch only involves the RFC portion of the MISO Market. If the PJM market is the source or the sink for the transfer, the dispatch involves the entire PJM market.

A comparison of the 2009 summer base conditions with that of the 2008 summer indicates the following changes that may be contributing factors affecting the loading of critical interfaces and facilities. Among the changes in modeling between the 2009 summer base case and the 2008 summer base case are:

5.5.2.1 Changes in Installed Generation

- 611 MW net generation increase within RFC-MISO
- 883 MW net generation increase within PJM
- 4542 MW net generation increase within the New York and Ontario Areas of NPCC

5.5.2.2 Changes in Generation Dispatch

- 2039 MW net generation decrease within RFC-MISO
- 2554 MW net generation increase within PJM
- 424 MW net generation decrease within NPCC

5.5.2.3 Changes in scheduled Net Interchange

- RFC-MISO to PJM is 835 MW higher
- NPCC to RFC-MISO is unchanged
- PJM to NPCC is 105 MW lower

Changes have been made since last summer to utilize actual market bid information in the base case and transfer dispatches whenever it is feasible.

For the 2009 summer period, the Keith-Waterman J5D Phase Angle Regulator is in service and regulating. The Lambton-St. Clair Phase Angle Regulators on the L4D and L51D circuits are in place but are bypassed for normal operation. Both phase angle regulators can be used in response to emergency conditions, if necessary. The phase angle regulator on the Scott-Bunce Creek B3N circuit is unavailable and its replacement is currently expected in 2010. The B3N circuit is in-service and operating as a free flowing tie line.

Assuming all transmission facilities are in service, power flows on the PJM, RFC-MISO, and NPCC bulk power transmission systems are within acceptable limits for the power transfers modeled in this base case. Also, assuming all operating procedures are appropriately employed, no single contingency on the bulk power transmission system will overload the remaining facilities, which are affected significantly by the transfers reported in this study.

The differences between the 2009 and the 2008 summer FCITC and FCTTC limits for the transfer analysis are provided below, with the first and second FCITC limits identified for the 2009 summer period indicated. All transfer limits presented in this report have been rounded down to the nearest 50 MW.

The following facilities contributed to the limits on regional transfers:

- Seward-Florence 115 kV line (western Pennsylvania)
- Lenox-Tiffany 115 kV line (northeastern Pennsylvania)
- St. Clair-Mohican #2 120 kV (Ontario-Michigan interface area)

The transfer limits changed as follows from 2008:

- NPCC to PJM: 2150 MW lower
- NPCC to RFC-MISO: 2050 MW lower
- PJM to NPCC: 850 MW higher
- RFC-MISO to NPCC: 1000 MW higher

Close coordination will be necessary to maintain adequate transmission reliability between the RFC and NPCC systems.

5.6 NERC LTRA

In October 2009, NERC issued its annual Long Term Reliability Assessment (LTRA), analyzing reliability conditions across the North American continent[33]. This report describes transmission additions, generation projections, and reserve capability by reliability council area. Both RFC and NPCC show that, within a ten year planning horizon, they are expected to have sufficient reserves to meet reliability needs. The RFC area is projected to add significant new natural gas capacity to its system, while in NPCC energy efficiency is the main projected resource-equivalent. Between the two reliability areas, almost 4,000 miles of transmission is projected to be constructed within a ten-year time frame. These generation and infrastructure improvements will ensure both areas meet LOLE of 1 day in ten years in the 2018 calendar year.

5.7 Eastern Interconnection Planning Collaborative

Early in 2009, several Planning Authorities in the Eastern Interconnection initiated discussions on expanding their regional transmission expansion planning work being conducted in accordance with Order 890 principles. Working with the backdrop of interregional coordination and joint studies, with heightened

[33] Available online at http://www.nerc.com/files/2009_LTRA.pdf

interest in strengthening the transmission grid to facilitate greater interregional power transfers, 17 Eastern Interconnection Planning Authorities met on April 8, 2009 to begin discussion focusing on the creation of the Eastern Interconnection Planning Collaborative (EIPC). Further meetings drew other Planning Authorities into the discussion, and led to a commitment to move ahead with the concept of a collaborative approach to the roll-up of regionally based plans to facilitate analyses with an interconnection-wide scope.

Significant work has been completed to create the structure of the EIPC. An agreement has been signed by 24 Planning Authorities, representing approximately 95% of the customer demand in the Eastern Interconnection. The EIPC structure consists of the Planning Authorities forming an Analysis Team, under the guidance and direction of an executive committee. A technical committee comprised of regional planning experts will provide support to the organization.

A fundamental tenant of the EIPC is that fully coordinated interconnection transmission analyses can be done most effectively through an approach that builds and expands on existing regional processes, leverages the existing planning expertise within those regional planning processes, and utilizes a coordinated roll-up of the existing regional plans as a starting point. The EIPC will:

- Build upon existing sub-regional and regional models of the bulk power system and refine them as necessary to support interregional analysis of the combined regional plans for the entire Eastern Interconnection
- Incorporate current local and regional plans across the entire Eastern Interconnection, so that consistency is built-in from the beginning
- Perform analysis of the regional plans on an interconnection-wide basis to identify greater opportunities for efficiencies and improvements, both at the seams and within each region, necessary to fully recognize regional benefits
- Provide a feedback mechanism where the results from analyses performed on an interconnection-wide basis can be used to inform the regional planning processes

While the Planning Authorities were forming the analysis team and advancing the concept of the EIPC, they also worked together to prepare a proposal to DOE for funding of the initial study work under the American Recovery and Reinvestment Act. The availability of federal funding would allow the EIPC to jump-start its process, allowing it to assign staff to create detailed transmission models and consider resource expansion scenarios. The application for DOE funding was submitted on September 14, 2009 by PJM Interconnection, LLC on behalf of all interested parties[34]. The application was accepted by DOE on December 18, 2009. The proposal incorporates the use of resources from eight Planning Authorities acting as principal investigators on the project, with support from the other Planning Authorities on the analysis team. Additional subcontractor resources to perform economic analysis, to supplement the technical work of the Planning Authorities, to facilitate the stakeholder process, and to provide dedicated full-time project leadership are included in the proposal.

Efforts are underway to create the EIPC stakeholder process and design the multi-constituency stakeholder steering committee. On October 13, 2009 and again on October 16, 2009 the Analysis Team held initial stakeholder webinars that were open to the public. The purpose of these webinars was to introduce the EIPC concept and explain its origin to those less familiar with the development that has already taken place, to describe the proposal submitted to DOE for funding as part of the Funding Opportunity Announcement (FOA), and to start to collect information and feedback on various aspects on the next

[34] Details of the proposal submitted to DOE on behalf of the EIPC have been made publically available and can be found on the EIPC website (www.eipconline.com).

steps in development of the stakeholder process. The analysis team envisions that these webinars are a first step in continuing discussions that will result in a long-term, robust stakeholder process.

5.8 Fuel Diversity Issues

Fuel diversity is an important aspect in interregional planning. It encompasses the diversity of the energy sources across the entire footprint of the three ISO/RTOs as well as the operational flexibility and coordination among these ISO/RTOs in the case of a temporary fuel supply shortage or disruption. Several factors have encouraged the development of renewable generation projects which would further diversify the supply of fuel. These include the states' Renewable Portfolio Standards and related programs (discussed in Section 7), tax incentives, and environmental regulations. In the future, the growth of renewable resources will play a larger role in diversifying supply-side energy sources.
Table 5-1 shows the energy resource diversity of the each of the three ISO/RTOs for 2009.

	Nuclear	Coal	Nat Gas	Oil	Hydro	Other Ren	Wind	Total
ISO NE	36,231	14,558	50,667	895	9,772	7,041	261	119,425
	30.3%	12.2%	42.4%	0.7%	8.2%	5.9%	0.2%	100.0%
NYISO	43,487	12,618	47,259	195	26,420	2,888	2,108	134,975
	32.2%	9.3%	35.0%	0.1%	19.6%	2.1%	1.6%	100.0%
PJM	249,262	349,090	65,497	1,697	7,771	7,251	5,693	686,261
	36.3%	50.9%	9.5%	0.2%	1.1%	1.1%	0.8%	100.0%
Total	328,980	376,266	163,423	2,787	43,963	17,180	8,062	940,661
	35.0%	40.0%	17.4%	0.3%	4.7%	1.8%	0.9%	100.0%

Table 5-1: NCSP09 Fuel Diversity 2009 Energy by Fuel Source (GWh & %)

The table shows relatively similar diversity for both ISO-NE and NYISO with natural gas as the dominant power plant fuel source while PJM's most dominant power plant fuel source is coal.

New England

New England is highly dependent on natural gas as primary fuel for regional power plants. Several regional natural gas sector projects, however, have been recently completed and have helped to diversify the sources of natural gas supply that is delivered to the region. Liquefied Natural Gas (LNG) supplies about 20% to 25% of the overall natural gas supply to the region on a peak winter day. In addition to Suez LNG's Distrigas of Massachusetts (DOMAC), the region has two new interconnects to new sources of LNG: the Northeast Gateway Deepwater Port offshore of Gloucester, MA, and the Canaport LNG import and storage terminal located in Saint John, New Brunswick. A third LNG project is planned for commercial operation in early 2010, the Suez LNG Neptune Project, which is similar to the existing deepwater port facility located offshore of Gloucester, MA.

There also have been new and expanded pipelines that directly or indirectly improve the natural gas delivery capability into and throughout New England. These pipeline projects have also worked to improve the bidirectional deliverability of regional pipeline, from a historical flow perspective. New natural gas storage projects have also been recently completed in both New York and Pennsylvania. These new underground gas storage projects add capacity for storing additional supply close to area market centers.

Finally, as a result of FERC Order 698[35] and other initiatives, there has been improved communications and coordination between the regional electric and natural gas operators. Several new procedures and protocols are have been instituted between the parties to respond to emergencies within either the electrical or the natural gas sector.

In addition to securing needed supplies of natural gas, resource diversity within New England is expanding. Renewable projects are under development across the region, in part as a result of state Renewable Portfolio Standards. New wind energy projects have been commercialized, and others are scheduled to follow.

New York ISO

Over recent years, in response to improved and more stringent environmental regulations, generators have increased the use of natural gas in place of oil and coal. While this provides environmental benefits, New York also needs to safeguard against becoming overly dependent on any one particular resource for meeting its energy needs, as fuel supply disruptions or other factors could pose reliability risks and/or cause significantly increased price levels and volatility. It is important to continue safe operation of nuclear, coal, natural gas, oil, and hydroelectric generation resources in ways that support New York's energy, environmental and economic objectives. Similarly, there is particular value in the continued availability of dual fuel generation capability, i.e., natural gas/oil, especially in the New York City area for continued ability to shift to oil should there be natural gas delivery problems. New York also needs to pursue the evaluation and development of advanced coal technologies.

Energy efficiency and renewable resources can contribute to meeting climate change and energy security goals, while also providing significant economic benefits. As the State continues to support the expansion of variable generation resources, such as wind turbines, it is important that adequate availability of load-following generation capacity be assured[36].

PJM

PJM has a relatively diverse mix of available fuel supplies for its generation. (See Table 5.1) Coal and nuclear are the main current sources for PJM generation, comprising between 85-90% of the total on an energy basis. The balance of the supply is natural gas, water, wind, and miscellaneous other sources. Any long-term fuel disruption would be expected to cause a natural market shift to the remaining available sources. Given this mix of available fuel sources, PJM has options and market flexibility to compensate for the exposure of a fuel source disruption. PJM could be somewhat economically exposed to the retirement of older coal-fired generation in a scenario where could be major cost increases due to carbon legislation. This could make some coal-fired generation less competitive. In the near term, however, PJM has new and robust supplies of gas and, in the longer term, is within the geographic footprint of the Marcellus Shale

[35] FERC Order 698 is entitled "*Standards for Business Practices for Interstate Natural Gas Pipelines* (Docket No. RM96-1-027); *Standards for Business Practices for Public Utilities* (Docket No. RM05-5-001), with Final Rule Dated June 25, 2007."

[36] This text is from the New York State Energy Plan. For more information, see http://www.nysenergyplan.com/final/Electricity_Assessment_Resource_and_Markets.pdf

natural gas field, a major new that could produce competitive natural gas supply for years[37]. Coupled with the ongoing development of wind energy in PJM, and the ability to mitigate shorter term disruptions, resource fuel issues are a lower level concern for PJM.

5.9 Summary

Interregional planning is becoming increasingly proactive as shown by studies of broad areas that seek to solve problems over multiple systems. The numerous planning activities discussed in this section demonstrate that planning is coordinated among the Northeastern ISO/RTOs and with neighboring systems. NPCC continues to promote and participate fully in proposed joint studies with its neighboring regional reliability council, Reliability*First* Corp. (RFC). These studies assess the mutual interactions of the high voltage transmission systems of both regions as planned for the future, with particular emphasis on major planned transmission additions and interregional power transfer capabilities. The IRC has promoted an open and reliable planning process. In addition, ERAG studies examine interregional studies over a wide geographic footprint and the EIPC represents a new initiative that will result in interconnection-wide planning. The three ISO/RTO have fully coordinated their operations and planning to address fuel diversity issues. The three ISO/RTOs will continue participation in the forums summarized in this report and others to ensure a reliable and efficient bulk electric system in upcoming years.

[37] For more information on shale gas and other natural gas supplies, see http://www.interiso.com/public/meeting/20091218/20091218_northeast_natural_gas_system_update.pdf

6 Key Environmental Issues with Potential Interregional Impacts

This section provides basic information about the status of air and water regulations and policies that may affect the electric power generation of the three ISO/RTOs over the next five to ten-year planning period. The issues covered are attainment of standards for four criteria pollutants, which have been tightened by EPA, and can affect power plants. These pollutants are sulfur dioxide (SO_2) emissions nitrogen oxide (NO_x) emissions, particulate matter emissions (PM) and ozone (O_3). Also discussed are regional haze regulations, mercury regulations, carbon dioxide regulations and cap and trade programs, power plant cooling water regulations and coal combustion byproducts.. These issues are discussed in this section along with the key regulatory programs in place or under development to address them. These programs are and will continue to affect the costs of generating units, most notably coal and oil units, and collectively have the potential to affect interregional system reliability.

Generating electricity using fossil fuels results in air emissions that have been shown to be harmful to human health, the environment, or both. These emissions include sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM) , mercury (Hg) and carbon dioxide (CO_2). SO_2 and NO_X and emissions combine with cloud vapor to form acid rain, which negatively affects ecosystems and erodes physical structures. NO_X and volatile organic compounds (VOCs) react with heat from the sun—typically in the afternoon of warmer days from May through September—to form ozone (O_3).[38] Mercury is a naturally occurring chemical found in coal, air, water, and the soil and in harmful concentrations in fish. Particulate matter (PM) contributes to acid rain, smog and haze, and carbon dioxide has the potential to contribute to global climate change.

Many power plants also take up water from surrounding waterways for cooling purposes, then discharge the heated water back into the environment. Both the uptake and discharge processes can have negative impacts on the ecosystems and habitats of those waterways. Coal plants' combustion byproducts are receiving new attention by EPA following the leakage from TVA's Kingston Plant's ash pond in 2008.

New, stricter federal, regional, and state environmental regulations are being implemented over the next 10 years that with the goal of reducing regional air emission levels from power plants and other emitting sources as well as the adverse impacts that power plants have on water quality. To minimize emissions and comply with these regulations, some existing fossil fuel plants likely will need to add controls, use cleaner fuels, or apply some combination of both measures. If the economics of switching to alternative fuels or adding emission controls is not favorable, some facilities may curtail operations or shut down. Fossil and nuclear plants may also be required to reduce their cooling water impacts.

Individually or together, directly or indirectly, these regulations, with the associated higher costs for compliance, could raise the costs to produce electricity for certain plants in the northeastern United States. This, in turn, may affect the revenues of the affected generators and effectively raise wholesale electric energy costs and, potentially, consumer electricity rates. These regulations also could affect system reliability and eliminate the possibility of adding new resources in certain areas, or at least make it difficult to site these resources. Another potential result is the development of more renewable energy sources than are currently planned and, longer term, more nuclear plants.

[38] VOCs come principally from the transportation sector.

Any planning to meet these environmental, economic and reliability requirements must be done collaboratively among the region's stakeholders, including the ISO/RTOs and their stakeholders, and state environmental and energy agencies.

6.1 EPA's Criteria Pollutants Affecting Power Plants

Under the *Clean Air Act*, EPA has established six criteria pollutants (CPs) that are considered harmful to human health, property, and ecosystems. These six pollutants are sulfur dioxide, nitrogen dioxide, ozone, carbon monoxide (CO), lead (Pb), and particulate matter in two sizes—2.5 microns ($PM_{2.5}$) and 10 microns (PM_{10}). Among these pollutants are several that fossil fuel plants emit directly and others that are formed from these emissions through chemical reactions in the atmosphere.

To identify whether the ambient air levels of these pollutants are harmful, the EPA has established National Ambient Air Quality Standards (NAAQS). If a criteria pollutant is shown to be at a level above the NAAQS for a certain area (usually a county or state), the area is considered a *nonattainment area* for that specific criteria pollutant. To meet the NAAQS for a specific pollutant over a designated time period, each area must develop or revise its air quality plan (i.e., a state implementation plan, SIP) for that pollutant.[39] A part of these plans is a requirement for new power plants and existing power plants undergoing certain types of modifications to use *best available control technologies* (BACT) or the generally more stringent, technically achievable *lowest available emission rate* (LAER).[40] Facilities sited in attainment areas require BACTs, whereas facilities sited in nonattainment areas require LAERs. In addition, any new plant in a nonattainment area must acquire *offsets* from existing emission sources that have reduced emissions in that same nonattainment area. Sources that have reduced emissions have been allocated these offsets, which can be traded in the emissions market.

Throughout the region served by the three ISO/RTOS the criteria pollutants may be in attainment in some areas and not in others which typically are more urban areas. The three criteria pollutants that are of importance for fossil power plants are ambient levels of SO_2, NO_x (as a precursor to ozone formation) and PM. Ozone levels in many areas of the three ISO/RTOs are not in compliance with NAAQS. Because the most effective way to reduce ozone levels is to reduce emissions of ozone precursors, i.e. NO_x and VOCs, the precursors are regulated. These regulations are under various programs separate from the NAAQS program. Power plant NO_X emissions have been a major target for reductions because of NO_X's role in ozone production.

Sulfur Dioxide (SO_2)

SO_2 has an annual standard 30 parts per billion (ppb) and a 24-hour standard 140 ppb. However, in November of 2009 EPA proposed eliminating the 24-hour standard and instead establishing a one hour

[39] State environmental regulatory agencies submit SIPs to the regional EPA office for review and approval.

[40] BACTs are pollution control measures mandated by the CAA based on the maximum degree that each pollutant can be reduced with consideration of energy, environmental, and economic impacts. State and local permitting agencies typically determine BACTs on a case-by-case basis, and the technologies are implemented through the application of production processes or other available methods. LAERs are the most stringent CAA designations for the levels of control required for major emission sources in CAA nonattainment areas. LAER technologies are the most effective pollution-control measures regardless of cost.

standard in the range of 50 to 100 ppb. It would retain the annual standard. The EPA must issue a final standard by June 2010[41].

Nitrogen Dioxide (NO_2)

The annual standard for NO_2 of 53 ppb has not changed in 35 years. However, the EPA proposed in January of 2010 a new one-hour NO_2 standard of 100 ppb. After new monitoring is in place by January 1, 2013, and then three years of data have been accumulated, the EPA will re-designate the areas of non-attainment for this new standard[42].

Fine Particulates ($PM_{2.5}$)

While there are urban areas within the region of the three ISO/RTOs that are not in attainment of a 2006 annual standard for $PM_{2.5}$ of 15 µg/m^3, the EPA is reviewing the standard and is expected to promulgate a new one in 2011 with non attainment designations made in 2013[43]. $PM_{2.5}$ also has a 24-hour standard of 35 µg/m^3 and that has not changed.

Ozone (O_3)

The eight-hour NAAQS ozone standard underwent a change by EPA in March 2008 being reduced from 84 ppb to 75 ppb. This new standard was challenged in court and, in January of 2010, EPA proposed a new stricter standard in the range of 60 to 70 ppb. EPA will make a final determination by August 2010. The state SIPs to demonstrate attainment will be due by the end of 2013[44]. Figure 7-1 shows using 2007 ozone monitoring data for the Northeastern states, the increasing number of nonattainment areas as the standard moves from the old to the current one, and for the proposed range of the new standard.

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[41] "EPA Proposes Stronger Air Quality Standards for Sulfur Dioxide /New standard to protect millions of the nation's most vulnerable citizens", News Release, U.S. EPA, November 17, 2009 http://yosemite.epa.gov/opa/admpress.nsf/0/f4dcb340a6d5236085257671000770756

[42] EPA Fact Sheet: "Final Revisions to the National Ambient Air Quality Standards for Nitrogen Dioxide", January 22, 2010, http://www.epa.gov/air/nitrogenoxides/pdfs/20100122fs.pdf

[43] Email to J. Platts from J. Moskal, EPA Region 1, January 15, 2009.

[44] EPA Fact Sheet: "Proposal to Revise the National Ambient Air Quality Standard for Ozone", January 6, 2010, http://www.epa.gov/air/ozonepollution/pdfs/fs20100106std.pdf

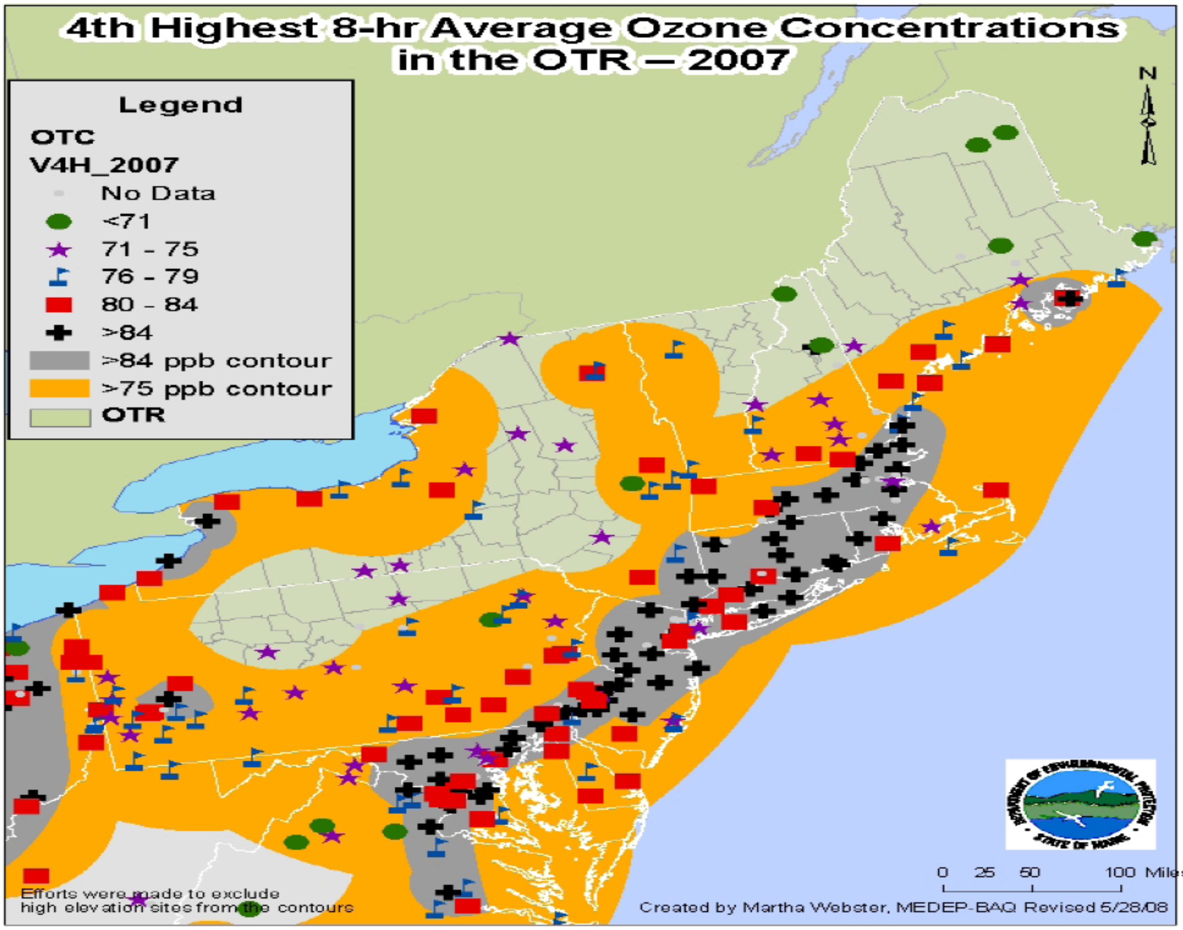

Figure 6-1 Increasing contours/regions of ozone non-attainment in the Northeast for vary ozone standards using 2007 ozone monitoring data.

Ozone Attainment and SO_2 Reductions

Ozone attainment is being implemented by the EPA principally through reductions in NO_x emissions through its Clean Air Interstate Rule (CAIR) and the Ozone Transport Commission's High Electric Demand Day (HEDD) Memorandum of Understanding (MOU). SO_2 reductions are part of CAIR as SO_2 contributes to smog.

6.1.5.1 CAIR

In March 2005, with revisions in April 2006, the Environmental Protection Agency (EPA) established the *Clean Air Interstate Rule* (CAIR) to reduce NO_x emissions, a precursor to ozone (O_3) and particulates, and SO_2 emissions, a precursor to particulates, across 28 eastern states and the District of Columbia.[45] CAIR caps NO_X emissions from major power plants in the CAIR region at 1.5 million tons starting in

[45] Rulemaking on Section 126 Petition From North Carolina To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Revisions to the Clean Air Interstate Rule; Revisions to the Acid Rain Program, *Federal Register, Vol. 71, No. 82* April 28, 2006, p. 25328-25469, available at http://edocket.access.gpo.gov/2006/pdf/06-2692.pdf.

2009 and at 1.3 million tons in 2015, andSO_2 emissions at 3.6 million tons in 2010 and 2.5 million tons by 2020.[46] CAIR replaced previous NO_x cap-and-trade programs that were implemented over smaller regions in the Northeast that began in 1999, and modified the SO_2 Trading Program under Title IV of the 1990 Clean Air Act Amendments.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the entire *Clean Air Interstate Rule* because it found a number of flaws with the rule.[47] However, on December 29, 2008, the court reversed its July decision and reinstated CAIR indefinitely until the U.S. Environmental Protection Agency (EPA) amends the rule or parties appeal the court's decision.[48] This reinstatement of CAIR affects essentially all the states within the region served by the three ISO/RTOs and their power plants. EPA plans to propose a replacement rule for CAIR in the Spring of 2010 and issue a final rule a year later[49].

CAIR has effect of raising the operating cost of generating units in the near term. Recent allowances prices for NO_x have been close to \$650/ton, and for SO_2 \$70/allowance or \$140/ton.[50] For a typical coal unit with an SO_2 emissions rate of 1 lb/mmBtu and a NO_x emissions rate of 0.5lb/mmBtu, this would translate to an increase in operating cost of about \$2.30/MWh, based on a 10,000 mmBtu unit.[51] The actual costs for each unit will depend upon fuel type, combustion configuration, and abatement technologies installed. Given the wide region over which NO_x and SO_2 allowances can be traded, it is unlikely that any reliability issues stemming from lack of availability of allowances will arise, but generation costs could rise if the demand for allowances increases.

6.1.5.2 HEDD

To further reduce NO_X emissions on ozone violation days in the more severe ozone nonattainment states, six states in the Northeast corridor through their membership in the Ozone Transport Commission established a program for to voluntarily commit to reducing NO_X emissions on days with high electricity demand, which are proxies for high ozone days.[52] The total HEDD NO_x reduction commitment by the six states in the program is 135 tons per day, and each state's commitment is shown in Table 6-1.[53] New

[46] See description of emissions reductions at http://www.epa.gov/cair/charts_files/cair_emissions_costs.pdf.

[47] North Carolina v. EPA, No. 05-1244, Slip Op. (D.C. Cir., July 11, 2008); http://pacer.cadc.uscourts.gov/docs/common/opinions/200807/05-1244-1127017.pdf.

[48] EPA has stated it will take approximately two years to formulate and finalize a new rule that will replace the current rule.

[49] "Update on EPA Rule Making", Presentation at Connecticut DEP SIPRAC meeting by Dave Conroy of EPA Region 1, November, 13, 2009.

[50] For November 2009 NO_x prices see http://new.evomarkets.com/pdf_documents/November%20NOx%20Market%20Update.pdf, and for SO_2 prices see http://new.evomarkets.com/pdf_documents/November%20SO2%20Market%20Update.pdf. Current vintage SO_2 allowances are traded at a ratio of 2 allowances per ton.

[51] This assumes a heat rate of 10mmBtu/MWh with \$0.70/MWh due to SO_2 and \$1.60/MWh due to NO_x.

[52] *Memorandum of Understanding (MOU) Among the States of the Ozone Transport Commission Concerning the Incorporation of High Electric Demand Day Emission Reduction Strategies into Ozone Attainment State Implementation Planning* (Washington, DC: Ozone Transport Commission, March 2, 2007); http://www.otcair.org/document.asp?fview=Report.

The six HEDD states are Connecticut, New York, New Jersey, Pennsylvania, Delaware, and Maryland.

[53] *Memorandum of Understanding (MOU) Among the States of the Ozone Transport Commission Concerning the Incorporation of High Electric Demand Day Emission Reduction Strategies into Ozone Attainment State Implementation Planning* (Washington, DC: Ozone Transport Commission, March 2, 2007); http://www.otcair.org/document.asp?fview=Report.

York's commitment is about 38% of the total and three states with the next largest HEDD commitments total about 48%.

State	HEDD Commitment Tons per Day	Percent
Connecticut	11.7	8.7%
New York	50.8	37.7%
New Jersey	19.8	14.7%
Pennsylvania	21.8	16.2%
Delaware	7.3	5.4%
Maryland	23.5	17.4%
Total	**134.9**	**100.0%**

Table 6–1: OTC States' HEDD Commitments

The Northeast States for Coordinated Air Use Management (NESCAUM) reported that oil-fired steam units and peaking combustion turbines that have no NO_X controls generate a high proportion of NO_X emissions on peak ozone days.[54] The HEDD MOU lists as options for NO_x reductions alternatives such as additional NO_X controls, repowering or retirement, reducing output, implementing energy efficiency and demand response measures, or emissions caps on HEDDs to meet the HEDD commitment. An example of the correlation between HEDDs and instances of exceeding the ozone standard is shown in Figure 6-2 for the New England region for the 2008 ozone season. The figure shows that the ozone standard was exceeded at high system load levels. There were, however, days when the ozone standard was exceeded occurring at load levels below 70% of the region's summer peak.

[54] *High Electric Demand Day and Air Quality in the Northeast* (White Paper) (Boston: NESCAUM; June 5, 2006); http://www.nescaum.org/documents/high-electric-demand-day-and-air-quality-in-the-northeast. NESCAUM is a nonprofit association of air quality agencies in the six New England states plus New York and New Jersey that provides scientific, technical, analytical, and policy support to the air quality programs of these Northeast states.

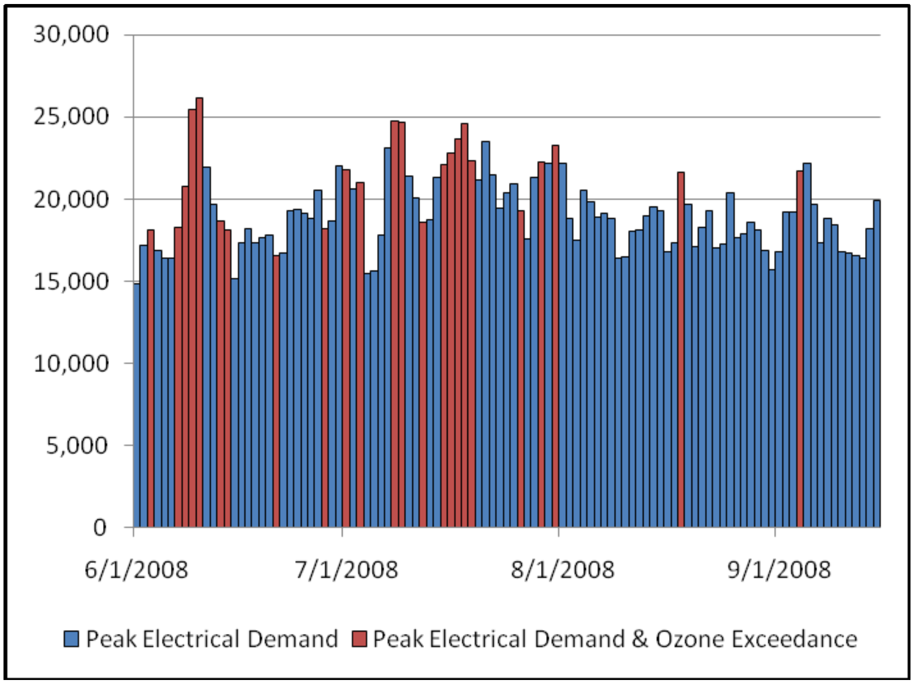

Figure 6-2: New England's 2008 electricity load with ozone violations (75 ppb) for the 2008 ozone season (June 1 through September 15). Source EPA Region 1

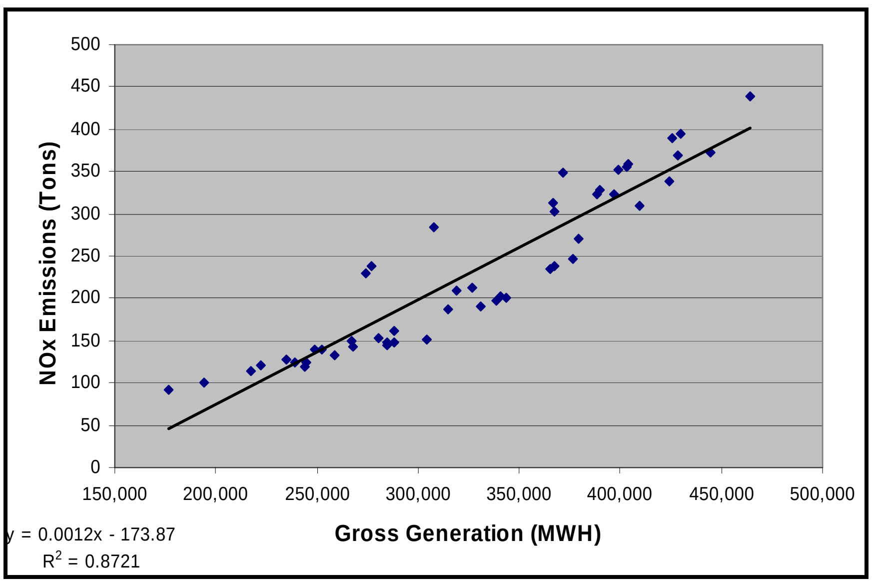

Figure 6-3: New York electric generation NO_X emissions vs. generation on high ozone days 2005-2007

Figure 6-3 shows a strong correlation for NO_X emissions and generation in New York on high ozone days during the period 2005-2007.

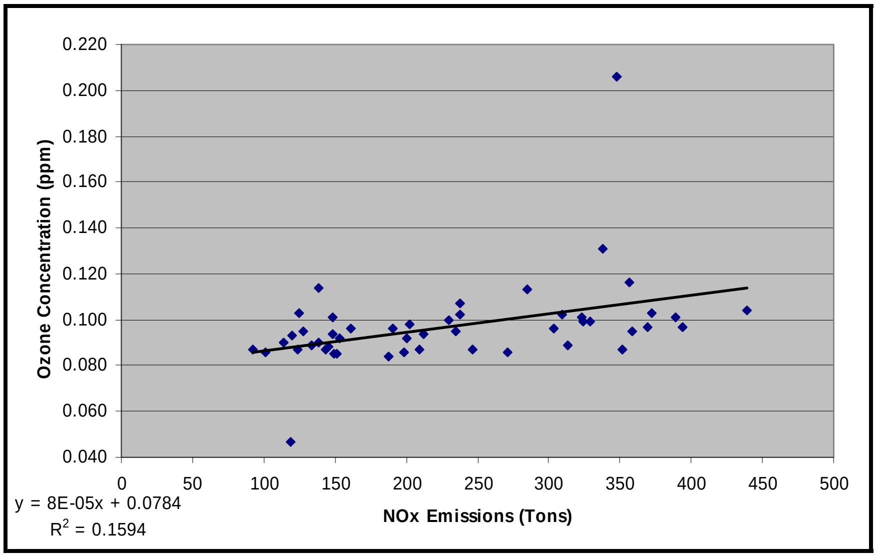

Figure 6-4: Ozone Concentration vs. NYISO Net Generation for days above the ozone standard (84 ppb) for 2005-2008

However, Figure 6-4 shows the correlation between generation levels and ozone concentration in New York is much weaker. Following this correlation to its limit, one notes that operating the NYISO system with zero NOx emissions (which is not possible), New York would still have days that exceed the ozone standard. From this figure it is apparent that other sources are contributing to ozone non-attainment besides fossil generation. This indicates that ozone attainment can only be achieved on a regional basis by controlling the broader array of the precursors to ozone formation.

Each state is developing its own strategy and regulations to implement its HEDD commitment.[55] The ISO/RTO region can likely anticipate that environmental regulations will continue to keep pressure on electric generators to lower NOx emissions as the region seeks to achieve attainment of the ozone standard. The three ISO/RTOs will monitor if and how the HEDD program affects the reliability of the power system. Regional Haze for Protection of Visibility in National Parks and Wilderness Areas

The pollutants that most impair visibility are SO_2, NO_X, and particulate matter. In 1999, EPA passed the *Regional Haze Rule* to improve the visibility in 156 national parks and wilderness areas.[56] The rule requires the states, in coordination with EPA, the National Park Service, U.S. Fish and Wildlife Service, U.S. Forest Service, and other interested parties to develop and implement SIPs to reduce the pollution that impairs visibility.

On June 5, 2005, EPA finalized amendments to the *Regional Haze Rule*. The amendments require facilities built between 1962 and 1977 that have the potential to emit more than 250 tons annually of visibility-impairing pollution to use *best available retrofit technology* (BART) to reduce emissions. On October 5, 2006, EPA finalized requirements for an emissions trading program as part of the *Regional Haze Rule*. These requirements allow state and tribal governments to demonstrate the effectiveness of an emissions trading program as an alternative to satisfying the BART requirements. As of January 9, 2009

[55] According to the MOU rules are to be in place no later than 2012.

[56] EPA's regulatory actions related to visibility are summarized online at http://www.epa.gov/air/visibility/actions.html. Additional information about the Regional Haze Program is available at "EPA's Regional Haze Program;" http://www.epa.gov/air/visibility/program.html.

the EPA found 13 states and the District of Columbia, in the region served by three ISO/RTOs, failed to submit their regional haze SIPs that were due in December of 2007[57].

In the region served by the three ISO/RTOs, three multi-state organizations are coordinating the planning for meeting the regional haze requirements and developing the technical basis for the states' SIPs. These are the Mid-Atlantic/Northeast Visibility Union (MANE-VU), the Midwest Regional Organization (Midwest RPO) and the Visibility Improvement State and Tribal Association of the Southeast (VISTAS)[58].

6.2 Mercury

The Clean Air Act regulates mercury as an air toxic or hazardous air pollutant As its first regulation of mercury from coal plants, in 2005 the EPA promulgated a Clean Air Mercury Rule. This required performance standards and a declining cap in mercury emissions from coal plants. In 2008 the rule was vacated by a federal court. As a result of a consent decree EPA must issue Maximum Achievable Control Technology (MACT) regulations by November 2011. The new MACT must be no less stringent than the emissions limit achieved by the best controlled existing source. In some states mercury regulations are in place requiring from 80 to 95% reduction of uncontrolled mercury emissions, or meeting a specified mercury emissions rate in lbs/MWh[59].

6.3 Carbon Dioxide (CO_2) Regulation and Cap and Trade Programs

This section summarizes the Regional Greenhouse Gas Initiative (RGGI), discusses other regional cap and trade proposals to reduce greenhouse gases, and proposed federal cap and trade bills.

RGGI

On January 1, 2009 RGGI took effect as a commitment among ten Northeastern states to cap carbon dioxide emissions from fossil power plants 25 MW and larger in those states. The states include those served by ISO New England, NYISO and three states in PJM (NJ, DE and MD). The annual 10-state cap is 188 million (short) tons through 2014. Each state is allocated a share of the allowances, as shown in Table 7-2 on the basis of historical emissions and negotiations.[60] From 2015 to 2018, the cap will decrease 2.5% per year, or a total of 10% by 2018 to 169.3 million tons. At that time, the allocation for the New England states would be reduced to 50.2 million tons, New York's to 57.9 million tons the three PJM RGGI states to 61.2 tons.

State	CO_2 Allocation Million (Short) Tons
Connecticut	10.70

[57] "EPA Makes Findings of Failure to Submit State Implementation Plans (SIPs) -- 1999 Regional Haze Program", http://www.epa.gov/visibility/actions.html

[58] MANE-VU states include: Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, Northern Virginia, and suburbs of Washington, D.C. Midwest RPO states include: Illinois, Indiana, Michigan, Ohio, and Wisconsin. VISTAS States and Tribes include: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia and the Eastern Band of the Cherokee Indians.

[59] "Expect New Mercury Rules by 2011" Coal Power, December 10, 2009, http://www.coalpowermag.com/environmental/Expect-New-Mercury-Rules-by-2011_231.html

[60] Under RGGI, one allowance equals the limited right to emit one ton of CO_2.

Maine	5.95
Massachusetts	26.66
New Hampshire	8.62
Rhode Island	2.66
Vermont	1.23
New York	64.31
New Jersey	22.89
Delaware	7.56
Maryland	37.50
Total RGGI	**188.08**

Table 6-2: RGGI States Annual Allowance Allocations for 2009 to 2014

RGGI was implemented through individual state regulations. These regulations require over 685 fossil fuel generating units in RGGI states rated 25 MW or greater and administered by the three ISO/RTOs to have RGGI allowances to cover their CO_2 emissions over a three-year compliance period, the first one being 2009 to 2011. The first three-year compliance-period "true-up" deadline is March 1, 2012, for the compliance period ending December 31, 2011.[61] Plans call for quarterly auctions, and as of December 2009, RGGI, Inc. has held six allowance auctions: two in 2008 and two in 2009. **Error! Reference source not found.** shows the results of these auctions for the 10 RGGI states combined[62].

Date	2009 Allowances Sold for 2009–2011 (Tons)[(b)]	Clearing Price ($)	2012 Allowances Sold for 2012–2014 (Tons)[(b)]	Clearing Price ($)
Sep 25, 2008	12,565,387[(c)]	3.07	–	–
Dec 17, 2008	31,505,898	3.38	–	–
Mar 17, 2009	31,513,765	3.51	2,175,513	3.05
Jun 17, 2009	30,887,620	3.23	2,172,540	2.06
Sep 9, 2009	28,408,945	2.19	2,172,540	1.87
Dec 2, 2009	28,591,698	2.05	2,172,540	1.86
Total	**163,473,313**		**8,119,593**	

Table 6-3:RGGI Allowance Auctions through the Fourth Quarter of 2009

(b) Any unused allowances purchased in one auction can be carried forward to the next compliance period (i.e., banked).

(c) The number of allowances sold is lower since not all states participated in this first auction.

The RGGI states auctioned varying percentages of their RGGI allocations with many auctioning close to 100%. Generally, the states expect to use most of the auction proceeds for energy-efficiency programs and other clean energy investments. In the six auctions to date a total of 163.5 million 2009 allowances and 6.5 million 2012 allowances have been sold. The total revenues from the six auctions are $494.4 million generated by over 100 bidders.

[61] The *true-up deadline* is the date by which RGGI-affected entities must have allowances and any offsets in their RGGI "allowance account" to cover their level of emissions from the previous three-year period.

[62] For more information, see Source: http://www.rggi.org/co2-auctions/results

The generators affected by RGGI are responsible for acquiring the allowances they need based on their projected operation and corresponding CO_2 emissions over the three-year period. Generators were the major purchasers of auction allowances. They may also use the secondary market to supplement the allowances obtained from the RGGI auctions. Secondary market prices have been higher than the 2008–2009 auction prices, but under $4/ton.[63] Beside the generators purchasing allowances in the RGGI auctions, they may use early-reduction allowances (i.e., reductions made in 2006 through 2008 below the RGGI historical emissions baseline), or use a combination of both measures. Generators also may use offsets created by reductions in GHG emissions in five sectors outside electricity generation[64].

The reduction of CO_2 emissions is achieved through a combination of the reduction of the use of electricity and switching from higher-emitting units that are typically low in cost to lower-emitting units that are typically higher in cost. At the CO_2 prices seen in RGGI, there would be very little switching from coal or oil and gas steam to natural gas units, and as shown in the recent PJM whitepaper, it would take a CO_2 price in excess of $30/ton to induce a great deal of switching from coal to combined cycle natural gas.[65] Consequently, the reliability impacts of RGGI are currently minimal and the most visible impacts will be in terms of wholesale power prices. For every $1/ton price of CO_2, this adds approximately $1/MWh to the cost of a typical coal unit, about $0.42/MWh to a typical combined cycle gas unit, and about $0.63/MWh to a new gas combustion turbine. Typically, the unit that sets the marginal price in wholesale markets emits CO_2. The marginal units in New York and New England are most frequently fueled by natural gas, while in PJM coal is on the margin over 70 percent of the time. As shown in PJM's whitepaper, on average in PJM an assumed $10/ton CO_2 price would translate into a $7.50-$8/MWh increase in load-weighted average LMP to its area.[66]

Other Regional Cap and Trade Programs

Two other existing and proposed cap and trade programs are also summarized briefly as they may influence the design of a federal cap and trade program that is being proposed in the U.S. Congress.

6.3.2.1 Western Climate Initiative (WCI)

The WCI is a proposed program to cap and then reduce greenhouse gas emissions from six western states (CA, OR, WA, , NM, UT, MT) and four Canadian provinces (BC, QUE, ONT, MAN)[67]. There are also five U.S. observer states, six Mexican observer states and two Canadian observer provinces[68]. The WCI's equivalent CO_2 emissions are to be capped at approximately 1,000 million tons as compared to the RGGI cap of 188 million tons. The WCI covers other economy sectors in addition to electric generation. The WCI cap begins in 2012 and will decrease to a level that is 15% below 2005 emissions by 2020. The

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[63] "Market Comment," Carbon Market North America, *Point Carbon News*: Vol. 4 Issue 11 (March 20, 2009); http://www.pointcarbon.com/news/cmna/1.1081890.

[64] The allowable offsets include 1) capturing and combusting methane from landfill gas; 2) reducing sulfur hexafluoride (SF_6) leaks from electricity transmission and distribution equipment and recycling the SF_6; 3) improving propane, oil, and gas end-use efficiency; 4) avoided methane emissions from agricultural manure management operations; and 5) taking up CO_2 through afforestation.

[65] "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market," available at http://www.pjm.com/documents/~/media/documents/reports/20090127-carbon-emissions-whitepaper.ashx.

[66] "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market," available at http://www.pjm.com/documents/~/media/documents/reports/20090127-carbon-emissions-whitepaper.ashx.

[67] Azizona recently pulled out of the WCI.

[68] Colorado, Idaho, Kansas, Nevada, Wyoming, Baja California, Sonora, Chihuahua, Coahuila, Nuevo Leon, Tamaulipas, Saskatchewan and Nova Scotia. http://www.westernclimateinitiative.org/

proposed program design and plan have been agreed to by each of the participants, which are now beginning the development of their own specific rules to implement the proposed program. The plan provides for the use of allowances from other greenhouse gas control programs such as RGGI. Up to 49% of the required reductions can be accounted for through the use of such allowances and offsets.

6.3.2.2 Midwestern GHG Reduction Accord

In November 2007 six Midwestern states plus Manitoba Province signed a Midwestern GHG Reduction Accord (Accord) with the goal of developing GHG reduction targets and a regional cap and trade program[69]. In June, 2009 an Accord advisory group developed specific recommendations for the targets and a cap and trade program design. The reduction targets recommended include a 20% reduction from 2005 GHG emission levels and similarly an 80% reduction by 2050. The targets would apply to mostly all sectors of the economy: electric generation and imports, industrial combustion and processes, fuels used in the residential, commercial and industrial areas and transportation. The advisory group gave more detailed recommendations and developed a model rule. These recommendations are currently being reviewed by the members in the Accord.

Federal Cap and Trade Legislation

On June 2009, the U.S. House of Representatives passed climate legislation based on a proposed bill by U.S. Representatives Edward Markey and Henry Waxman.[70] The bill provides a framework for debate and sets emissions caps for reducing GHGs 17% by 2020 from a 2005 baseline, 42% below the baseline by 2030, and 83% below the baseline by 2050. Senators John Kerry and Barbara Boxer have drafted a cap and trade bill based largely on the Waxman Markey bill but it has a slightly more aggressive reduction target of 20% in 2020 from a 2005 baseline. A recent estimate of allowances prices under the Kerry Boxer bill was made by Point Carbon using its U.S. model for carbon prices[71]. It model results showed average prices would be $15 per metric ton (or $13.6 per short ton) for the period 2012-2019.

Many issues remain to craft a federal cap and trade bill, including allowance allocations. While it is uncertain if and when any cap and trade bill will be passed by the Congress, there is some possibility for it happening. The implications for the continuation of RGGI when a federal bill might go into effect are also uncertain.

EPA's CO_2 Regulation and Future Air Regulation Strategy

In April 2007, the U.S. Supreme Court ordered EPA to evaluate CO_2 as a potential pollutant to regulate.[72] On April 17, 2009, EPA issued an Endangerment Finding that CO_2 and five other greenhouse gas (GHG) emissions are pollutants that threaten public health and welfare.[73] This means EPA has the responsibility to address the impact of GHGs and can regulate CO_2 similar to other air pollutants. The court ruling allows EPA to regulate GHGs, even if Congress does not take such action. The EPA is taking steps in this direction as it has already established GHG emissions reporting regulations that went into effect in 2010.

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[69] Member U.S. states are Iowa, Illinois, Kansas, Michigan, Minnesota, Wisconsin. Observer states/provinces are Indiana, Ohio, Ontario and South Dakota. http://www.midwesternaccord.org/

[70] *Carbon Analysis: Climate Bill Passes House* (New York: Evolution Markets, July 1, 2009); http://new.evomarkets.com/pdf_documents/ANALYSIS:%20Climate%20Bill%20Passes%20House.pdf.

[71] Energy Central News, October 9, 2009.

[72] Massachusetts et al. Petitioners v. EPA et al. (No. 05-1120), 549 U.S. 497 (Decided April 2, 2007); http://www.supremecourtus.gov/opinions/06pdf/05-1120.pdf.

[73] "EPA News Release, April 17, 2009; http://yosemite.epa.gov/opa/admpress.nsf/0/0EF7DF675805295D8525759B00566924.

EPA has also proposed GHG permitting requirements. that would apply to facilities with over 25,000 metric tons of GHG. The permitting would be part of the current Title V air permits renewed every five years. BACT or energy efficiency measures will be required but these have not been defined by EPA[74].

EPA is planning to issue a number of new air regulations coordinated as a multi-pollutant or sector-based strategy[75]. This strategy would include replacements for earlier programs to control soot and smog-forming pollutants, mercury, the replacement for CAIR, review of national air quality standards for six criteria pollutants and coordination with long-term climate legislation. This strategy may provide a complete and longer term perspective of future air regulations that power plants will be facing.

6.4 Power Plant Cooling Water Issues

Section 316b of the Clean Water Act deals with cooling water intake requirements and mandates a significant reduction of the impacts of impingement and entrainment of aquatic organisms in existing power plants[76]. The reduction measures must reflect the use of best available technology (BAT). The BAT requirements are implemented when the existing National Pollution Discharge Elimination System (NPDES) permits for power plants expire and subsequently are renewed, providing the opportunity to include the current BAT requirements. Currently, EPA provides guidance on renewal individually, permit by permit.

On April 1, 2009, the U.S. Supreme Court delivered an opinion that benefit/cost analyses could be used in determining the BAT permit requirements, which can significantly affect the outcome of deciding the BAT cooling intake requirements.[77] Without considering benefit/cost, existing generating plants potentially would need to retrofit cooling towers to meet these requirements.
The potential for cooling tower retrofit requirements on key existing plants could have an impact on a significant number of generators in the region. It also could affect system reliability through the reduction of plant capacity and, possibly, extended construction outages of key generating facilities. The ISO/RTOs will monitor EPA's follow up regarding the Supreme Court's decision on the permitting process and the use of a benefit/cost application by generators. The ISO/RTOs will need to determine whether any reliability evaluation is needed regarding the potential for retrofitting existing plants with cooling towers.

6.5 Coal Combustion By-Products

Coal combustion byproducts (ash, slag and particulates) typically are processed through settling ponds and the ash removed is often sold for beneficial uses. In the U.S over 120 million tons of byproducts are produced and about 43% of them are used beneficially. The U.S DOE has a goal of 50% beneficial use by 2011. The ash pond rupture and spillage into the neighboring environment at the TVA Kingston Plant

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[74] "Fact Sheet -- Proposed Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule", EPA September 30, 2009. http://www.epa.gov/NSR/fs20090930action.html

[75] Email from John Moskal, EPA Region 1, October 29, 2009.

[76] Cooling Water Intake Structures,‖ *CWA Section 316b; Phase I—New Facilities. Fact Sheet. EPA-821-F-01-01* (Washington,

DC: U.S. EPA, November 2001); http://www.epa.gov/waterscience/316b/phase1/316bph1fs.html.

[77] 07-588 Entergy Corporation v. Riverkeeper, Inc (Lower Court Case No. 04-6692ag, 04-6699ag) (Granted April 14, 2008); http://www.supremecourtus.gov/qp/07-00588qp.pdf.

in 2008 caused EPA to review the regulations for these ponds. New proposed regulations were due from EPA in December of 2009 but have not yet been released. The possibility of regulating ash ponds as toxic wastes under the Resource Conservation and Recovery Act (RCRA) could add $11 billion dollars annually to the cost of operating U.S, coal plants[78].

6.6 Summary and Conclusions

The region served by the three ISORTOs faces increasing environmental regulations, principally related to tightening of NAAQS, ozone attainment, regional haze, mercury emissions, climate change, use of cooling water, and coal combustion products. These will affect the future economics and operation of fossil generating plants by adding costs for emission allowances, requiring use of low emitting fuels, and/or adding capital costs for environmental controls. Other environmental mitigation strategies may constrain fossil generating units' energy production due to limited availability or the expense of emission allowances. All of these issues could affect the economics and operation of the interregional power system in the future. New generation dispatch and commitment patterns could result from shifting costs and limitations of generation capacity or energy production. There will be a continuing need to monitor and evaluate proposed new environmental developments as they occur or are proposed, and to provide feedback and input to environmental regulators on the impacts of these developments as needed.

NERC has undertaken a study to evaluate the potential retirements of fossil generators due to impacts of four environmental regulations: CAIR, mercury, coal combustion byproducts, and CWA Section 316b. The study will assess the potential for retirements using an economic criteria and the potential impact on system reliability and potential mitigation strategies.[79]

[78] "Presentation of Environmental Issues Affecting Three ISO/RTOs (Slide 21)", Peter Carney, NYISO, December 18, 2009.

[79] 2010 Special Reliability Scenario Assessment: Early Fossil-Fired Unit Retirements, Potential Impacts of Environmental Regulations, NERC, Draft 1/22/2010.

7 Renewable Portfolio Standards

Most all states served by the three ISO/RTOs have renewable portfolio standards or related energy policies. In some cases the states also include energy efficiency goals. Table 7-1 below summarizes the goals of these renewable portfolio standards and related policies, including any special features for the 20 states plus the District of Columbia served by of the three ISO/RTOs. Four of the states have no RPS, but one of them has a state goal for renewable energy supply.

These renewable portfolio standards and related policies specify different types of renewable energy technologies. These typically encompass solar, wind, landfill gas, biomass and other special types of energy technologies that vary among the states. Most of the states also have one or more classes for existing renewable resources that typically cover small hydro, biomass energy and refuse plants. The load serving entities that must comply with the standard do so by buying Renewable Energy Credits (RECs) from projects within the states or nearby ones The states may also have an alternative compliance payment feature the may be used in place of meeting the RPS by buying RECs. This serves as a price cap on the price of RECs

Table 7-1

Renewable Portfolio Standards in the States of the Three ISO/RTOs

State	New Renewable Classes – %	Target Year	Comments
Maine	10	2017	
New Hampshire	11	2020	Also has 0.3% target for solar by 2014
Vermont	25*	2025	Not a RPS but a state goal for energy from forest and farms renewable sources
Massachusetts	15	2020	Has an energy goal of 25% reduction by 2020 plus a 5% target for alternative technologies
Rhode Island	14	2019	
Connecticut	20	2020	Has a Class III for combined heat and power and energy efficiency
New York	30	2015	Includes large hydro
New Jersey	22.5	2020-2021	2.1% minimum must be from solar
Pennsylvania	18	2021	Includes new and existing in 2 tiers defined by technologies
Delaware	20	2019-2020	2% must be from solar
Maryland	20	2022	2% must be from solar
District of Columbia	20	2020	0.4% minimum for solar
Virginia	15%	2025	Voluntary. Percent based on 2007 sales
West Virginia	25%	2025	
Kentucky			Has no RPS
North Carolina	12.5%	2021	0.2% must be from solar by 2018
Tennessee			Has no RPS
Ohio	25	2024	Alternative technology standard with 12.5% from renewables, solar minimum of 0.5%
Indiana			Has no RPS

Illinois	25	2024-2025	18.75% from wind, 1.5% from solar by 2015-2016
Michigan	10%	2015	Specific MW targets for larger utilities

7.1 New England States

Five of the New England states have RPSs that focus on developing new renewable resources. They also include existing resources and, in some states, special categories for combined heat and power (CHP) and energy efficiency (EE). Vermont has a renewable resource development goal but no RPS. Considering all of these programs, the New England goal for 2020 is to have about 30% of its energy derived from renewable resources and energy efficiency measures.

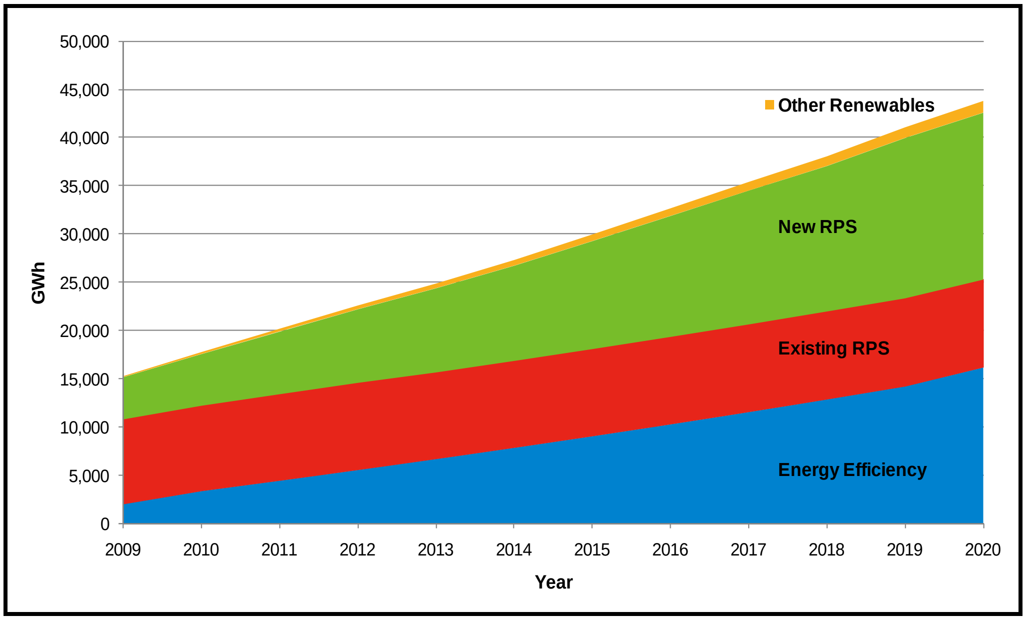

Figure 7-1: New England States projected cumulative targets for renewables and energy efficiency based on RPSs and related policies.

7.2 New York

The New York State Renewable Portfolio Standard (RPS), established by the state Public Service Commission (PSC) in 2004, seeks to enlarge the proportion of renewable electricity used by retail customers. In December 2009, the PSC expanded the RPS goal to increase the proportion of renewable electricity consumed by New Yorkers from 25 percent to 30 percent by 2015. The new 30 percent goal equates to a target of 10.4 million megawatt hours in 2015.

The Renewable Energy Assessment of *New York State Energy Plan 2009* reports[80], "New York produced 28,067 gigawatt hours (GWh) from renewable resources in 2007, representing 16.8 percent of the State's total electricity generation. Of that, conventional hydropower provided 90.0 percent of the State's renewable electricity, followed by biomass (5.6 percent), wind (3.1 percent) and biogas (1.3 percent)."

[80] The *New York State Energy Plan 2009* is available online at http://www.nysenergyplan.com/

In New York State, the RPS program is funded through a surcharge on the customer bills from investor-owned utilities. The New York State Energy Research and Development Authority (NYSERDA) conducts annual auctions for the purchase of Renewable Energy Credits (RECs) which are proposed to be produced from new qualified renewable generation facilities.

7.3 PJM States

In PJM, Pennsylvania, New Jersey, Delaware, Maryland, Illinois, Ohio, North Carolina, Michigan, West Virginia, Virginia and the District of Columbia have RPS requirements or goals. Tennessee, Kentucky, and Indiana do not have RPS requirements. Figure 7-2 below shows the projected amount of renewable energy that will be needed in PJM to achieve these renewable energy mandates and goals. In 2020, PJM states are projected to require 100 million MWh of renewable energy, which equates to nearly 11% of the PJM forecasted load. This excludes energy efficiency, CHP, and alternative technologies that are not generally considered renewable resources within the PJM footprint.

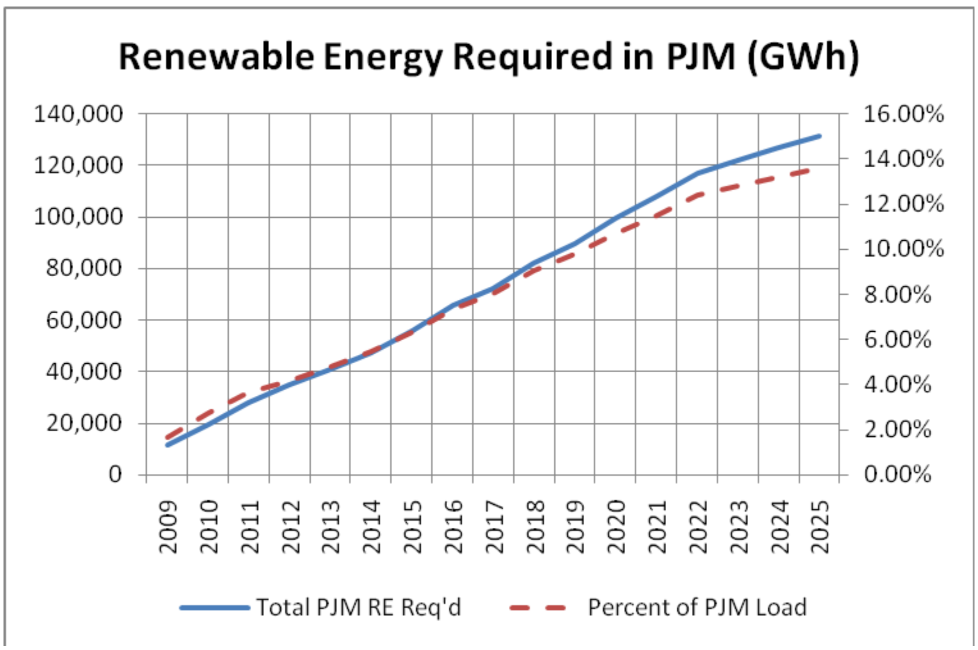

Figure 7-2: PJM States projected cumulative targets for renewables based on RPSs and related policies.

7.4 Interconnection Queues

Renewable resource development is being driven in part by renewable portfolio standards (RPS) that most states throughout the three ISO/RTOs region have established. Table 7–2 shows that most of this development consists of wind resources and, currently, there is over 55,000 MW of wind projects in the three ISO/RTO queues, mostly in PJM. Much is being done to analyze and develop ways to smoothly integrate wind into the operation of each ISO/RTO.

The ISO NE Interconnection Queue of October 1, 2009 shows a total of 3,622 MW from 62 new renewable resource projects in various stages of planning. Approximately 87% of the MW total is wind generation with most of it onshore.

The NYISO October Interconnection Queue Report shows 65 wind projects in the interconnection process with a total capacity of 9,792 MW. The report also shows nine LFG projects with a combined capacity of 131 MW. The queue also shows seven fuel cell projects totaling 140 MW. Biomass and landfill gas projects in New York tend to be of a size or at an interconnection voltage that does not put them under the jurisdiction of the NYISO.

The PJM November Interconnection Queue Report shows that there are 412 projects with a total nameplate capacity of 45,654 MW most of which are wind. The report also shows hydro, biomass, and methane projects.

ISO/RTO	Onshore Wind	Offshore Wind	Biomass	Water	LFG	Fuel Cells	Solar	Total
ISO NE[(a)]	2267 (39)	876 (3)	427 (12)	17 (5)	36 (2)	9 (1)	0	3,622 (62)
NYISO[(b)]	7,831 (61)	1,961 (4)	16.3 (2)	21.6 (4)	130.8 (9)	140 (7)	0	10,100.7 (87)
PJM[(c)]	41,407 (211)	1,516 (5)	451 (18)	1,123 (26)	426 (82)	0	728 (70)	45,654 (412)
Total	**51,505 (311)**	**4,353 (12)**	**894 (32)**	**1,165 (35)**	**593 (93)**	**149 (8)**	**728 (70)**	**59,386 (561)**

Table 7–2: Renewable Resource Projects in the ISO NE, NYISO and PJM Queues – MW (# of Projects)

(a) Based on October 1, 2009 Interconnection Queue

(b) Based on October 2009, Interconnection Queue

(c) Based on November 2009 Interconnection Queue

7.5 Conclusions

Current projects in the three ISO/RTO's Generator Interconnection Queue could make significant contributions towards, and in many cases meet, state RPS goals. Additional projects may develop, but are not currently in the queues of ISO-NE, NYISO, and PJM. Renewable resources may also be imported from neighboring regions, including Canada. Alternatively, there may be some combination of reduced load energy consumption and load making alternative compliance payments that serves as a cap on the price that loads would need to pay for renewable resources to meet RPSs.

8 Wind and Renewable Resource Studies

This section covers studies related to the development of large wind and renewable resources in the three ISO/RTOs region. The integration of these resources presents operational challenges to each ISO/RTO, individually and collectively The JIPC is a venue through which ISO-NE, NYISO, and PJM communicate planning efforts to avoid duplication of work and to expedite solutions that will successfully integrate wind resources into the overall system. The ISO/RTOs are participating in several group efforts related to wind integration. The following section outlines some of the major study groups investigating wind issues at an interregional level

8.1 DOE and NERC Wind Integration Activities

This section describes the DOE and NERC wind integration activities.

Eastern Wind Integration and Transmission Study

The Eastern Wind Integration and Transmission Study (EWITS) is being funded by the Department of Energy's National Renewable Energy Lab (NREL)[81]. A report detailing study results was published in early 2010[82]. The summary in the report states that, "The EWITS results represent a first detailed look at a handful of future snapshots of the Eastern Interconnection as it could exist in 2024. The analysis was driven primarily by economic considerations, with important technical aspects related to bulk power system reliability represented approximately or through engineering judgments."[83] Additionally, the effort involved detailed analysis of operational considerations of wind integration.

The EWITS examined 4 scenarios of resource expansion with a focus on wind penetration:

- **Scenario 1, 20% penetration**—Resources sited in highest capacity onshore locations
- **Scenario 2, 20% penetration**—Resources sited with a blend of highest capacity onshore and onshore/offshore locations near load centers
- **Scenario 3, 20% penetration**—Resources sited with heavy usage onshore/offshore locations near load centers, considering eastern states' RPS targets as a factor
- **Scenario 4, 30% penetration—**Resources aggressively sited in both highest capacity onshore and onshore/offshore locations near load centers

Based on the top-down application of transmission methods for each of these scenarios, a conceptual transmission overlay of high voltage lines was developed for each scenario to integrate the resource additions. The transmission overlay also enabled study of enhanced levels of Eastern Interconnection market trading and shared provision of the likely increased need for transmission ancillary services. These transmission overlays did not attempt to optimize or minimize transmission integration costs. They did not fully develop transmission needed on underlying systems or the source or delivery points. The EWITS transmission method did, however, cap the conceptual transmission overlay development at levels that were supported by the approximations of market efficiency savings produced.

[81] While ISO New England was initially a participant in this study, it withdrew from the study effort before completion.

[82] The full report can be downloaded at http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf

[83] Eastern Wind Integration and Transmission Study, page 55

A primary feature of the EWITS study was to develop and apply techniques that assess wind integration impacts on reserve and load following requirements. Also, the study examined reliability impacts of the wind scenarios with commonly used software that determines the Loss of Load Expectation (LOLE). This software was used to estimate the load carrying capability of the wind resources including the benefits of the assumed transmission overlays. The EWITS recognizes the need for significant areas for additional study. For example, wind operation impacts did not directly and fully address the potential light load issues that could arise. Also, the reliability work recognized significant changes in results when actual wind variation from year to year is considered or actual operational wind farm data is examined. In spite of the areas for additional work, EWITS produced information to extend and advance the discussions of wind integration[84].

The scope of the new Eastern Interconnection Planning Collaborative (EIPC) places interconnection wide planning within its purview and the EWITS may be considered as an input to future national transmission planning efforts.. The EIPC is discussed in more detail in section 5.7 of this report.

NERC's Integration of Variable Generation Task Force

Reliably integrating large amounts of variable generation, such as wind, solar, and tidal generation resources into the bulk power system requires modifications to traditional planning and operating methods. To address these philosophical and technical issues, the NERC Planning and Operating Committee created the Integration of Variable Generation Task Force (IVGTF). In April 2009, the IVFGTF issued a report entitled *Accommodating High Levels of Variable Generation* which describes current experience and recommends enhanced practices, study, and coordination efforts for reliably integrating variable resources[85].

Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term bulk power system reliability: The goal of the current IVGTF effort is to identify what bulk power system planners must do to accommodate large amounts of variable generation and provide more consistency in reporting regional resource reliability assessment results. This includes, but is not limited to, methods to calculate energy and capacity, probabilistic analysis, coordinated generation/transmission planning approaches, study of distributed resources, impacts of integrating large amounts of storage and demand response, and wind plant modeling[86].

8.2 Wind Development and Integration Issues in New York, New England and PJM

This section presents the current status of wind development in the three ISO/RTOs and discusses the common issues among them on wind integration. While much work has been done to address the integration of wind projects into the systems by the three ISO/RTOs, this work is ongoing as number of new wind resources continues to grow. The current issues being addressed are assuring adequate transmission development for integrating wind, wind forecasting, automatic generation control, reserve and contingency requirements, low-voltage ride through, power factor and other issues. As wind grows on these systems, these issues will become more and more important for system reliability.

[84] The New England States Committee On Electricity has issued a document in response to this study: *Preliminary Observations on the Eastern Wind Integration and Transmission Study (EWITS)* http://www.nescoe.com/uploads/EWITS_Memo_to_PAC_-_for_release.pdf

[85] See http://www.nerc.com/docs/pc/ivgtf/IVGTF_Report_041609.pdf

[86] See http://www.nerc.com/filez/ivgtf.html

New York

New York State adopted a Renewable Portfolio Standard which requires 25% of New York States' electricity needs to 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 New York Power System (NYPS). The study was conducted by GE Power System Energy Consulting in fall of 2003 and completed by year end 2004 (hereafter referred to as "the 2004 Study").

The overall conclusions of the 2004 Study is the expectation that the NYPS can reliably accommodate up to a 10% penetration of wind generation or 3,300 MW with only minor adjustments to and extensions of its existing planning, operation, and reliability practices – e.g., forecasting of wind plant output. Since the completion of the NYISO/NYSERDA wind 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. Installed nameplate wind generation has now has grown to in excess of 1,200 MW and the NYISO interconnection queue significantly exceeds the 3,300 MW that was studied in the original report. In addition, the State of New York has increased its RPS standard to 30% by 2015. As a result, the NYISO has been studying the integration of wind plant penetration ranging from 3,500 MW to 8,000 MW. The integration of 8,000 megawatts (MW) of wind-generating resources into the NYPS is being studied for the year 2018. The final report is currently scheduled to be presented to market participants, finalized and released in the first quarter of 2010. The energy that is projected to be generated with the addition of these wind plants would comprise approximately 12% of the projected New York Control Area energy consumption in 2018.

The NYISO analysis indicates that for the 8 GW wind scenario approximately 8% of the upstate wind energy would be constrained and not deliverable without transmission upgrades, while off-shore would be fully deliverable. The NYISO is now conducting a study to determine the transmission upgrades that would be needed to improve the overall energy deliverability of the wind plants that are constrained. This analysis is scheduled for completion by February 2010.

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 generation. In the very short time frames (seconds-to-minute), 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.

Due to its intermittent nature, wind has more in common with the load than it does with conventional generation. Therefore, the primary metric of interest in assessing the impact of wind on system operations is the net load, which is defined as the load minus wind. It is the net load that the non-intermittent or conventional generation must be able to respond to. The study evaluated the impact of up to 8,000 MW of wind-generation resources on system variability. This analysis will have the potential for determining any need for increases or decreases in system regulating resources and ramping within an hour, between hours, and across multiple hours.

The study has determined that as the level of installed wind plant MW increases, system variability as measured by the net-load increases for the system as whole. The increase exceeds 20% on an average annual basis from current levels for the 8 GW wind scenario and 2018 loads. The level of increase varies by the season, month and time-of-day. This increased variability will result in operating challenges on a day-to-day basis due to the variability of wind in real-time and transmission congestion in some areas of the transmission system, possibly where it is currently not encountered. This will result in increased ramping as well as regulation requirements. The study showed that the max hourly regulation requirement is expected to increase from today's 275 MW to 425 MW with 8,000 MW of wind.

The study results preliminarily indicate the NYISO will need conventional generation to be more responsive in order to follow the increased power system variability. Overall, the NYISO has preliminarily determined that its day-ahead scheduling system and nominal five-minute dispatch and scheduling cycles will be capable of reliably integrating the levels of wind-generation studied. It will be the rare extreme events, e.g., the unanticipated drop off of a large amount of wind generation over very short period of time that could pose reliability challenges under the condition studied but these events can be addressed through heightened operational awareness when the potential for such events exist.

The NYISO study also looked at the issues related to the integration of intermittent resources, such as whether minimum generation levels required for conventional generation will impact the dispatch of wind resources. The answer to that question depends on how much of the forecasted wind resources forecasted day-ahead are realized and the ability of the system to adjust in day. Simulations have indicated that a significant over commitment day-ahead can result in wind resources being curtailed because of minimum generation issues as well as significantly cycling of conventional generation resources. Likewise, simulations have indicated that a significant under commitment day-ahead will most likely result in the NYISO drawing additional resources from its interconnection to neighboring areas to meet in real time energy requirements. These types of events should be very infrequent.

The NYISO's experience with existing wind-generation resources and the experience of other systems have already resulted in several initiatives to reliably integrate wind and respond to such events. To date the NYISO has:

- Established a centralized wind forecasting system
- Become the first grid operator to fully integrate wind resources with the economic dispatch of electricity
- Developed new market rules to expand the use of new energy storage systems that complement wind generation.

In conclusion, the levels of wind-generating resources studied in this scenario will likely pose increased operating challenges on a day-to-day basis as well as increased stress on transmission system infrastructure in many locations in upstate NY. However, the preliminary conclusion is that these challenges can be addressed through the operational processes already in place, enhancement to these processes as required, and through system reinforcements as needed. The NYISO cautions that the results of this study may not apply to significantly higher levels of wind plant penetration, e.g. at 20% and 30% of total energy. Such levels would require further study.

New England – Update on the New England Wind Integration Study

As of October 2009, about 90 MW of utility-scale wind generation projects were on line in the ISO's system, of which 81 MW are offered into the electric energy market. New England has over 3,100 MW of larger-scale wind projects in the Generator Interconnection Queue, with over 800 MW representing offshore projects and almost 2,200 MW representing onshore projects. Over 1,200 MW of larger-scale commercial wind farms could be operating by the end of 2010 on the basis of the resources in the queue.

The ISO's wind integration activities have three areas of focus: actively participating in NERC's Integrating Variable Generation Task Force (IVGTF), conducting a large-scale New England wind integration study—the New England Wind Integration Study (NEWIS), and facilitating the interconnection process for new wind generators.

Figure 8-1 shows areas in New England where the development of wind resources could potentially avoid environmentally sensitive and highly populated regions. The figure shows possible locations of up to 115 GW of onshore wind resources and 100 GW of offshore wind resources, but it is not a projection of total wind development. Most likely, only a small fraction of the potential 215 GW actually will be developed. Distributed wind development, which does not interconnect directly with the transmission system, also is possible, such as in local communities.

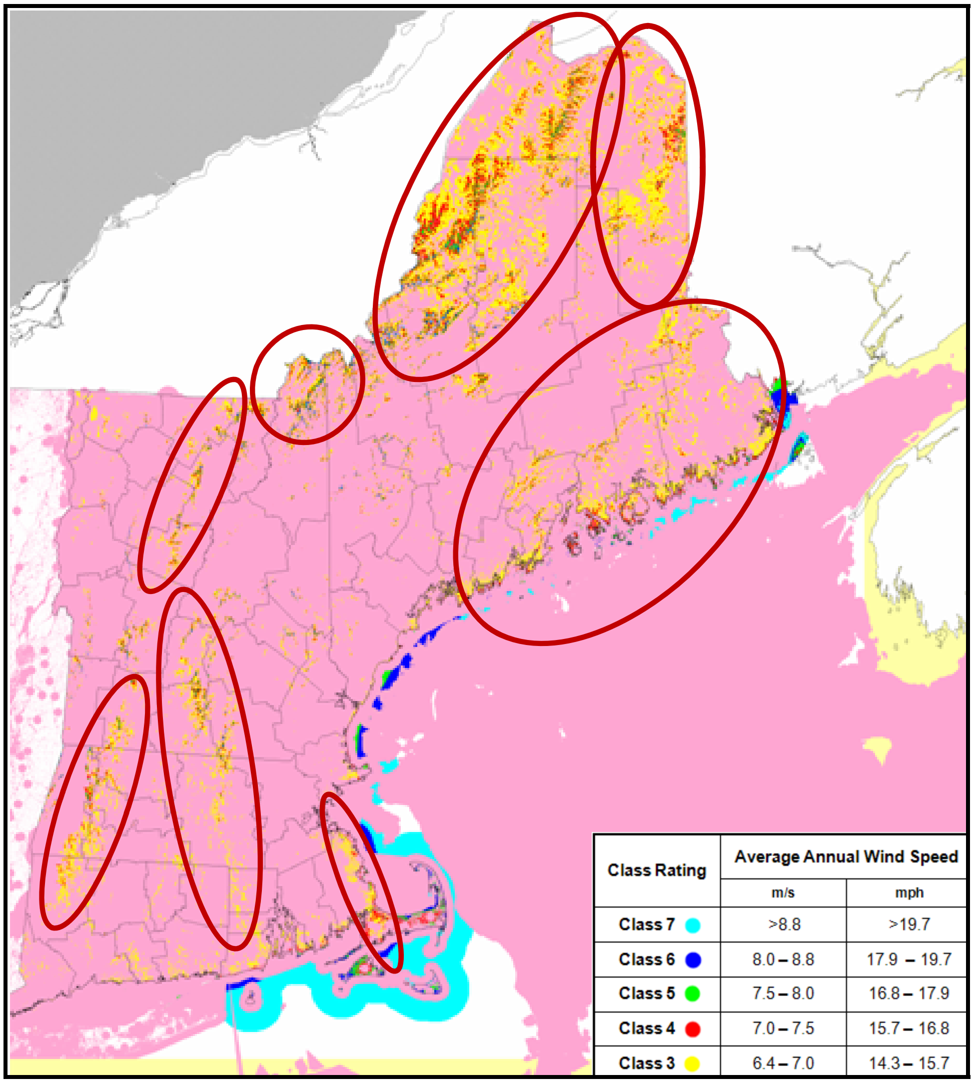

Figure 8-1: Areas in New England with the greatest wind potential.

Note: The pink indicates areas where the development of wind generation is less likely because of siting concerns and low annual wind speeds. The other colored areas are favorable for potential wind development .The ellipses show favorable clusters of the potential development of onshore wind generation. On the key, "m/s" refers to meters per second, and "mph" refers to miles per hour.

In 2008, the ISO issued a request for proposals (RFP) to conduct a New England Wind Integration Study (NEWIS).[87] The RFP has been awarded, and the study is underway. A vendor team led by General Electric Energy Applications and Systems Engineering, with support from three consultants (EnerNex, AWS Truewind, and WindLogics) is performing the comprehensive wind power integration study. All the work must be conducted during 2009 and 2010. The following subsection describes the drivers, goals, and the tasks of the study.

[87] The NEWIS RFP and related materials are available on the ISO's Web site; http://www.iso-ne.com/aboutiso/vendor/exhibits/index.html.

8.2.2.1 Drivers

Successfully integrating wind power generation into the power system presents technical challenges because the characteristics differ significantly from conventional generation. These characteristics include limited controllability and high variability of power produced by wind turbines and the uncertainty in forecasting the amount of power that can be produced. To some extent, the variability and uncertainty inherent to wind power can be mitigated by increasing the geographic diversity of the interconnected wind power resources. The operation and planning of the New England power system will be affected by the expansion of wind power resources in New York and neighboring Canadian provinces. These resource additions in neighboring regions will likely provide opportunities for closer coordinated operation among the systems, additional interregional power transfers, and new transmission tie lines.

8.2.2.2 Goals

The goals of the NEWIS are as follows:

- To determine, for the ISO New England Balancing Authority Area, the operational, planning, and market impacts of integrating large-scale wind power, as well as the measures available to the ISO for mitigating these impacts and facilitating the integration of wind resources
- To make recommendations for implementing these mitigation and facilitation measures

In particular, the study will identify the potential adverse operating conditions created or exacerbated by the variability and unpredictability of wind power and recommend potential corrective activities. The study aims to capture the unique characteristics of New England's electrical system and wind resources in terms of load and ramping profiles, geography, topology, supply and demand resource characteristics, and the unique impact wind profiles could have on system operations and planning as wind penetration increases. While the study will address these issues, it will not project the likely total development of wind-powered generation in New England.

8.2.2.3 Tasks

The study is planned for completion by mid-2010 and is being structured around five tasks:

Task 1: Wind Integration Study Survey. The project team is conducting a survey of national and international studies of integrating wind resources into bulk electric power systems. This includes ISO studies, such as Phases I and II of the *Technical Assessment of Onshore and Offshore Wind Generation Potential in New England* and the *New England Electricity Scenario Analysis*, and actual wind integration experiences in bulk electric power systems.[88] The objective of the survey is to determine the applicability of these studies, such as the specific tools used, to the ISO's wind integration studies. The information captured during this task will be used to refine the assumptions and deliverables of the remaining tasks of the study.

Task 2: Technical Requirements for Interconnection. This task includes the development of specific recommendations for technical requirements for wind generation, addressing such aspects as its ability to reliably withstand low-voltage conditions, provide voltage support to the system, and

[88] These materials are available on the ISO's Web site; http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/. *New England Electricity Scenario Analysis: Exploring the Economic, Reliability, and Environmental Impacts of Various Resource Outcomes for Meeting the Region's Future Electricity Needs* (ISO New England, August 2, 2007); http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf.

adjust megawatt output to support the operation of the system. The task also will include data and telemetry requirements, maintenance and scheduling requirements, high wind cutout behavior, and the development of best practice methods of the equivalent load-carrying capability (ELCC) calculation used for establishing capacity values for global and incremental wind power generation.

This task also will investigate and recommend wind power forecasting methods for both the very short-term timeframe, which is useful in real-time operations, and the short- to medium-term timeframe, which is useful in unit dispatch and day-ahead unit commitment.

Task 3: Mesoscale Wind Forecasting and Wind Plant Models.[89] The study will develop an accurate and flexible mesoscale forecasting model for the New England wind resource area (including offshore wind resources) to allow for the simulation of power system and wind generation operations and interactions (e.g., unit commitment, scheduling, load following, and regulation) over the timescales of interest. The model will be designed to produce realistic time-series wind data over all terrain types for at least 2004, 2005, and 2006 to quantify the effects of interannual variability in wind generation and systemwide load.

Task 4: Scenario Development and Analysis. This task will simulate and analyze the impacts of several wind-development scenarios in New England on the performance of the electric power system. The scenarios of the future system will consider various levels of wind development up to 20% of the projected annual consumption of electric energy. Sensitivity analyses will include the impacts of the diversity of the wind portfolio on the performance of the electric power system for scenarios of low diversity, high diversity, and high correlation with system load.

This analysis will lead to recommendations for modifying existing procedures, guidelines, and standards to reliably accommodate the integration of new wind generation. The evaluation also will include a review of the ISO's market design considering a high penetration of wind generation and how this scenario could affect system reliability, contribute to inefficient market operation of the bulk electric power system, or do a combination of both.

Task 5: Scenario Simulation and Analysis. This task will simulate and analyze detailed scenarios to assess the measures needed to successfully integrate a high penetration of wind generation. The investigation will assess the type of forecast needed, such as forecasting lead time, the required accuracy, and implementation issues. The simulations also will evaluate the use of on-line generation for load following, regulation, and reserve maintenance and deliverability; the production of air emissions; the effects of carbon cost; and the effects on LMPs. Measures that would facilitate the integration of wind, such as changes to market rules, the addition of electrical storage to the power system, and the use of demand response also will be studied.

8.2.2.4 Wind Generator Interconnection Facilitation

Wind generators wanting to interconnect to the ISO system face particular challenges attributable to the differences between wind power and conventional resources. ISO-NE steps for interconnecting and subsequently operating wind generation include the following:

- Completing all phases of the ISO's specific commissioning protocol

[89] Mesoscale forecasting is a regionwide meteorological forecasting generally over an area of five to several hundred kilometers.

- Meeting requirements for voice communications and data telemetry, depending on the type of markets in which the resource will be participating
- Designating an entity that has complete control over the resource and can be contacted at all times during normal and emergency conditions
- Submitting real-time, self-scheduling information so that the ISO can account for it in planning and operating analysis
- Providing other information, such as models, and meeting additional performance requirements, such as voltage control and dispatch

Additionally, wind generators are notified that the existing interconnection requirements are under review as part of the NEWIS, are interim, and may change once the ISO has received and evaluated the NEWIS recommendations.

8.2.2.5 Next Steps

The ISO plans to evaluate the recommendations from the study and will develop an implementation plan based on the outcomes of the NEWIS and other studies. In the near-term, results derived from NEWIS Task 2, Technical Requirements for Interconnection, will likely result in modifications to the ISO's interconnection requirements for wind generators. The balance of the wind integration efforts will be ranked by priority and be completed in accordance with the ISO's own project implementation schedule. The results of this study will help the region integrate significant wind resources into the electricity grid without impairing the reliability and operation of the grid.

PJM

PJM currently has approximately 2,530 MW of wind generation connected to the system with approximately 3,085 MW under construction. PJM has seen a significant increase in the number of interconnection requests for wind projects over the past several years and the current PJM interconnection queue has approximately two hundred and forty requests for interconnecting wind generation to PJM corresponding to over 43,000 MW of new wind generation. This represents a slight decrease in the past year. Wind represents roughly forty percent of all the generation in the PJM queue. Most of these wind projects are clustered in Pennsylvania and West Virginia along the Appalachian Mountains and in Illinois. PJM has also experienced requests for direct interconnection to the PJM market from wind projects geographically remote from the PJM territory.

PJM assigns a 13% capacity value to wind as a class of resources, unless a higher value can be justified by a project. The current PJM wind capacity value is based on PJM historical operational experience.

PJM has initiated several actions in response to this increased potential:

- Created the PJM Intermittent Resources Working Group (IRWG) to address market, operational, and reliability issues specific to intermittent resources such as wind, solar, and energy storage resources
- Implemented a centralized forecasting process for wind plant output
- Developed processes to integrate wind into PJM's market-based dispatch system
- Participated in JCSP and EWITS wind study initiatives

In 2010, the PJM IRWG will be:

- Examining grid interconnection standards
- Reviewing interconnection study methodologies
- Evaluating a potential PJM wind integration study to assess operational and reliability impacts associated with high levels of wind penetration

Generic Wind Integration Issues

The generic issues for wind integration are 1) transmission interconnection, 2) system flexibility, 3) operator awareness and practices, and 4) wind generation performance and standards.

Transmission: Wind resources tend to be concentrated in remote areas of the power system, which historically have had limited transmission capability. Expanding transmission will be a critical step in achieving the large scale integration of wind. 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 into the interregional power system.

System Flexibility: The bulk power system will require increased ramping capability and resources that can be dispatched quickly to accommodate the increased variability and uncertainty of generation such as wind. Resource planning must ensure that the bulk power system has the quantity of flexible supply and demand resources necessary to accommodate the increase in variable generation– e.g., storage capability or dynamic load such as plug-in hybrid electric vehicles. Markets, pricing regimes and minimum standards should be developed to provide signals about the system characteristics that are most valued for both existing generators and for developers and entities that are planning new generation.

Operator Awareness and Practices: Enhancements are required to existing operator practices, techniques and decision support tools to increase the operator awareness of new variable generation, and to operate future bulk power systems with large scale penetration of wind generation. Wind generation must be visible to, and controllable by, the system operator, similar to any other power plant so the system operator can maintain reliability. For instance, the NYISO requires existing wind plants to be visible to system operations and is utilizing a short-term centralized wind forecast system for real time operation to more accurately predict the magnitude and phase (i.e. timing) of wind generation plant output. In addition, based on its existing experience with operating wind plants, the NYISO has proposed to its market participants that wind plants participate in the NYISO economic dispatch/congestion management system in order to fully optimize the economics of the wind plants while maintaining reliability.

Wind Generation Plant Performance and Standards: Interconnection and generating plant standards need to be enhanced to ensure that variable generation's design and performance contribute to reliable operation of the power system. These include the need to standardize basic requirements, such as:

- Power factor range (and thus reactive power capability)
- Voltage regulation
- Fault-ride through (low voltage and high voltage)
- Inertial-response (the effective inertia of the generation as seen from the grid is often zero)
- The ability to control the MW ramp rates on wind turbines and/or curtail MW output

- The ability to participate in primary frequency control (governor action, automatic generation control, etc.)

In addition, improved wind plant models need to be developed, validated and standardized for all wind technologies, especially for use in conducting stability and transient analysis studies.

Appliance controllers and automated technologies that modify load characteristics, known as smart-grid technologies, can mitigate stress on the grid and prevent power outages during grid emergencies. Smart-grid technologies also can help integrate renewable energy resources into the grid and may reduce the need to build generation, transmission, and distribution systems. Technologies could also provide ancillary services, and possibly storage, both of which would facilitate the integration of wind resources. However, further research and development work is necessary.

Summary

Development of wind resources presents technical challenges for its successful integration. The JIPC is coordinating the solution to these challenges among the three ISO/RTOs, and the IPSAC is the vehicle to bring these issues to the attention of the stakeholders in the Northeast region.

8.3 Imports from Eastern Canada

The eastern Canadian premiers and Canadian utilities have a strategy to build over 13,000 MW of non-emitting hydro, wind, and nuclear-powered resources and intend to sell any excess power to Ontario and New England, typically outside eastern Canada's winter-peaking season.

Taking into consideration the seasonal load diversity previously referenced, some of the Canadian provinces also would expect to purchase power from the northeastern United States during their winter-peaking season. This is consistent with the goals of the Northeast International Committee on Energy (NICE), which has sought to reduce the overall emissions of greenhouse gases in the region and eastern Canada and to facilitate increased transfers of electrical energy between New England and the eastern Canadian provinces.[90] This plan also would diversify electric energy supplies for New England, provide additional sources of renewable energy, and potentially reduce costs to New England electric energy customers.

The overall strategy of increased transfers between New England and Canada requires the coordination of the respective transmission expansion plans in the Atlantic Provinces, Québec, and New England. The NICE currently is reviewing these transmission expansion plans and renewable resource development plans across the entire region to identify synergies between these system developments on either side of the international border[91]. For all projects that could have an interregional impact, ISO New England also will closely coordinate with all neighboring systems to study and implement these projects and ensure reliable system performance among the balancing authority areas. This has been the case with the Merchant and Elective Transmission Upgrades between the Canadian Provinces and New England, which are in various stages of development.

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[90] NICE includes representatives from the New England Governors and the Eastern Canadian Premiers (NEG/ECP). Additional information about NICE is available online as follows: 1) the NEG Conference Inc. Web site, "New England Governors' Conference Programs, NEGC Energy Programs," http://www.negc.org/energy.html; and 2) NEG/ECP Resolution 31-1 of the 31st Conference of New England Governors and Eastern Canadian Premiers, Resolution Concerning Energy and the Environment (Brudenell, Prince Edward Island: NEG/ECP, June 26, 2007),http://www.negc.org/documents/NEG-ECP_31-1.pdf.

[91] See http://newenglandgovernors.org/documents/Res_33-2.pdf

ISO New England has completed 2008 Economic Studies that examine the impacts of adding new resources in various amounts and system locations. The almost 300 scenarios including ones that increase imports from Canada also account for various levels of load and relief of transmission constraints. Results of these studies are can be found on the ISO New England website[92].

At the request of the New England Governors the ISO also conducted a study of the potential for renewable resources development of up to 12,000 MW in New England, onshore and offshore, plus 3000 MW from Canada[93]. This study showed that the development and integration of this much renewable (wind) capacity appears feasible if the necessary transmission can be developed. Conceptual designs of the transmission additions were developed along with their cost estimates. No detailed transmission system analysis was conducted in this study.

8.4 Summary

With almost 56,000 MW of wind resources in the respective ISO/RTO Interconnection Queues, and with several study efforts underway in the regions, the ISO/RTO's planning for the integration of these new resources is well underway. As results emerge, the ISO/RTOs will need to keep each other advised of potential operating concerns discovered through their analyses.

[92] "2008 Economic Studies Report", ISO New England, October 19, 2009.http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/2008_eco_report.pdf

[93] "New England 2030 Power System Study", Draft Report, ISO New England, September 8, 2009. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/eco_study_report_draft.pdf

9 Demand Side Resource Development

Demand side resources (DSR) may have peaking, intermediate, and baseload characteristics and utilize a variety of technologies that either modify the load or utilize distributed generation resources. Demand side resources may modify their electric energy consumption in response to incentives based on wholesale markets. Examples include high performance new buildings, thermal envelope improvements, high efficiency HVAC systems, and advanced lighting. Distributed generation may include a variety of units, such as combined heat and power, solar arrays, and small wind farms. The best locations for demand side resources are usually in areas where they can help serve load, reduce transmission congestion, and improve system reliability. Emergency diesel generators have permitting restrictions, but can serve a reliability function.

Underlying these initiatives is the FERC policy mandate that DSRs be allowed to participate in markets in a manner that is comparable to generation resources.[94] While demand resources may reduce the need to build physical infrastructure, successfully integrating demand-response resources into the electric power system presents many challenges. These include operational, planning, and market issues presented by this large penetration of demand-response resources.

9.1 PJM

PJM has a comprehensive program to ensure comparable treatment of demand side resources and alternatives. PJM incorporates quantities of Load Management (LM), Energy Efficiency (EE), Price Responsive Demand (PRD) and Behind-the-Meter (BtM) generation to supplement PJM's independently developed base, unrestricted load forecast. The Load Management component is composed of Interruptible Load for Reliability (ILR) and Demand Resource (DR) components. Through these FERC approved mechanisms, energy consuming entities have greatly enhanced access to options to reliably meet their electrical energy and capacity responsibilities.

The ILR portion of LM, forecasted for each PJM zone, represents the five-year historical average of zonal ILR (supplemented as needed with historical Active Load Management data). This five-year average is held constant for each year of the forecast.

The DR portion of LM, forecasted for each zone, equals the amount of DR cleared in PJM's three year forward Reliability Pricing Model (RPM) auctions. RPM procures the capacity required in PJM for system reliability. Products eligible to participate in RPM include generation, transmission upgrades, LM and EE. The amount of DR cleared in the last auction year is held constant for the remainder of the forecast.

The forecasted impact of approved EE programs equals the amount cleared in RPM auctions, and represents accelerated efficiency increases that would not otherwise occur, or would occur at a later time, without the EE program.

The impact of PRD equals the amount subscribed through the RPM process. The amount subscribed for the last RPM auction year is held constant for the remainder of the forecast.

BtM generation is eligible, in any planning period, to elect to be treated as as BtM and net against load or as an LM resource according to the rules of PJM's applicable tariffs and agreements. PJM Manual 14D, Appendix A contains additional information about treatment of BtM generation.

PJM's current load forecast includes over 7,000 MW of Load Management and Energy Efficiency in its long term forecast

PJM recently tested LM for its capability to provide its committed level of load reduction for the 2009/2010 delivery year. These test results, in aggregate, demonstrated a response of 118% of capacity commitments or 1,299 MW in excess of the 7,089 MW committed load reductions.

9.2 New York ISO

NYISO offers two demand response programs to support reliability: the Emergency Demand Response Program (EDRP) and the Installed Capacity-Special Case Resource Program (ICAP/SCR). Demand response resources may also participate in the NYISO's energy market through the Day-Ahead Demand Response Program (DADRP), or the ancillary services market through the Demand-Side Ancillary Services Program (DSASP). EDRP provides demand response resources with the opportunity to earn the greater of $500/MWh or the prevailing locational-based marginal price (LBMP) for energy consumption curtailments provided when the NYISO calls on them. The ICAP/SCR program allows end-use customers that meet certification requirements to offer unforced capacity (UCAP) to Load Serving Entities (LSEs). Special Case Resources can participate in the ICAP Market just like any other ICAP Resource. Resources are obligated to curtail when called upon to do so with two or more hours notice, provided that they are notified the day ahead of the possibility of such a call. The Targeted Demand Response Program (TDRP) was introduced in July 2007. TDRP is a NYISO reliability program that deploys existing EDRP and SCR resources on a voluntary basis, at the request of a transmission owner, in targeted subzones to solve local reliability problems. The TDRP program is currently available in Zone J, New York City. Subscriptions to the NYISO's demand response programs are at record levels. In 2009, 2,084 MW of ICAP/SCR resources will be on line, which is an increase of 761 MW over the 1,323 MW of resources in 2008. This additional SCR program participation significantly contributed to the NYISO determining that resource adequacy requirements will be met for the 2009-2018 study period.

In its 2009 Long Term Forecast (as reported in the 2009 Load & Capacity Report), the NYISO also included an analysis of the reliability impacts of New York's energy efficiency initiative intended to achieve a 15% reduction in energy use by 2015 (15 X 15)[95]. Pursuant to its Energy Efficiency Portfolio Standard, the New York State Public Service Commission (NYPSC) has taken initial steps to implement the New York Governor's initiative to lower energy consumption on the state's electric system by 15% of 2007 forecasted levels in 2015. Using a conservative assumption based on current authorized funding level of $335 million per year together with additional funds from the 2009 federal stimulus program, the NYISO determined, for its base case reliability analysis, that approximately 40% of the 15 X 15 goal would be achieved for reliability planning purposes. At that level, the energy efficiency savings would equate to a 1,485 MW decrease in the peak load forecast by 2015. This reduction in peak demand contributed significantly to the NYISO's determination that no new resources will be needed on the New York bulk power system for 2009-2018. The NYISO will vigilantly monitor the implementation of the 15

[95] NYISO Comprehensive Reliability Planning Process (CRPP) 2009 Reliability Needs Assessment, January 13, 2009, pp. 3-3 through 3-7.

x 15 programs to determine that they are in fact achieving their desired energy savings and peak demand reduction effects.

Finally, it should be noted that the NYPSC recently commenced a proceeding "to examine potential initiatives to promote demand response in parts of the state where peak load reduction would provide the greatest benefits."[96] The NYISO will fully participate in this proceeding.

9.3 ISO New England

Recognizing the application DSRs, the New England 2009 Regional System Plan ("RSP") states that demand resources of all types may provide reserve capacity and relief from capacity constraints, or they may support more economically efficient uses of electrical energy.[97] Referring to demand resources as an important component of well-functioning wholesale markets, the ISO has allowed DSRs to participate in its first two Forward Capacity Auctions ("FCAs").

The FCM demand resources that will begin delivery in the FCM's first capacity commitment period (i.e., June 1, 2010 to May 31, 2011) belong to one of two general categories: passive and active.

- **Passive projects** (e.g., energy efficiency), which are designed to save electric energy (MWh). The electric energy that passive projects save during peak hours helps fulfill ICRs. These projects do not reduce load based on real-time system conditions or ISO instructions. The FCM includes two types of passive projects:
    - **On peak**—passive, non-weather-sensitive loads, such as efficient lighting
    - **Seasonal peak**—passive, weather-sensitive loads, such as efficient heating and air conditioning (HVAC)
- **Active projects** (e.g., demand response), which are designed to reduce peaks in electric energy use and supply capacity by reducing peak load (MW). These resources can reduce load based on real-time system conditions or ISO instructions. The FCM includes two types of active projects:
    - **Real-time demand response—**active, individual resources, such as active load management and distributed generation at commercial and industrial facilities
    - **Real-time emergency generation—**active, emergency distributed generation

Of the 2,937 MW of demand resources that cleared in FCA #2 and will count toward satisfying the ICR for the 2011/2012 delivery year, passive demand-response resources represent 983 MW, or 33%, and active demand-response resources represent 1,954 MW, or 67%. To meet the ICR requirements imposed under the market rules, the active demand-response value includes a 600 MW cap placed on the use of emergency generators. **Error! Reference source not found.** shows the types and locations of demand resources that cleared in FCA #2.

[96] NYPSC Case 09-E-0115, Proceeding on Motion of the Commission to Consider Demand Response Initiatives, Order Instituting Proceeding (February 17, 2009).

[97] ISO New England 2009 Regional System Plan, p. 41.

Resource Type	ME	NH	VT	MA	CT	RI	Total
On-peak demand resource	26	57	69	378	125	58	**714**
Real-time demand-response resource	236	35	26	535	311	52	**1,195**
Real-time emergency-generation resource[(b)]	32	13	8	363	269	74	**759**
Seasonal-peak demand resource	0	0	0	19	248	2	**269**
Total	**294**	**106**	**103**	**1,296**	**952**	**186**	**2,937**[(c)]

Table 9-1: Demand-Resource Capacity that Cleared in FCA #2 (MW)[(a)]

(a) All megawatt values are increased to account for the reserve margin and loss factor. Totals may not equal the sum because of rounding.

(b) The use of real-time emergency-generation resources to meet the ICR is limited to 600 MW, but the 600 MW cap has not been applied to the values in this table.

(c) The 2,937 MW total of demand resources that cleared FCA #2 equals the 2,778 MW plus the 159 MW of excess RTEG that cleared in FCA #2.

The total demand-resource capacity represents approximately 9% of the representative ICR, with active resources representing approximately 5.5% of the net ICR, assuming 600 MW of RTEGs.

During the first Forward Capacity Auctions, 2,279 MW of demand resources cleared will count toward satisfying the net Installed Capacity Requirement (NICR) of 32,305 for the delivery year 2010/2011. Of the 2,279 MW that cleared, 700 MW, or 31%, represents passive demand-response resources, and 1,579 MW, or 69%, represents active demand-response resources. In the second FCA, approximately 2,900 MW of demand resources cleared the auction including 1000 MW of passive demand-response resources. To meet the ICR requirements imposed under the market rules, the active demand-response value includes a 600 MW cap placed on the use of emergency generators.

While demand resources may reduce the need to build physical infrastructure, successfully integrating demand-response resources into the electric power system presents many challenges. RSP09 reports on a stakeholder process to address operational, planning, and market issues presented by this large penetration of demand-response resources.

9.4 Conclusions

Reliable and cost-effective DSRs are given full and fair consideration, along with other resources available to address grid reliability and economic congestion problems, in the existing regional planning processes. Those processes recognize the increasing presence of DSRs in the system and integration issues are being addressed and coordinated by the ISO/RTOs.

10 Plans for Additional JIPC analysis

10.1 Market Efficiency Analysis

The scope of work calls conducting joint production cost analysis and assessing the effects of relaxing various combinations of constrained transmission interfaces in postulated increments of 500 MW to 1000 MW. The study will produce various metrics, including production cost, load serving entity energy expenses, environmental emissions, and locational marginal prices of "load bubble" areas. As indicated in Section 4.3.2, the initial results of NYISO/ISO-NE economic analysis will use IREMM and will be compared to other production cost programs to show consistency. IREMM analysis will be extended to the three ISO/RTO footprint. Follow-up analyses will then be conducted using a more detailed production cost program, such as PROMOD. All assumptions and results will be presented to the IPSAC for comment.

The Market Efficiency Analysis may identify areas where transmission upgrades would promote interregional transfers. The final identification of transmission upgrades would require follow-up transmission planning analysis and very detailed production cost simulations. A possible outcome previously discussed with IPSAC could be a southern New England to southeast New York to New Jersey tie.

10.2 Transmission Analysis

As discussed in Section 4.1.5, joint studies between New England and New York have demonstrated the feasibility of a new interconnection between Plattsburgh and Vermont. Prior to this or any related project being realized, the system benefits, alternatives, and final solutions would require thorough review through the NYSIO and ISO-NE open stakeholder processes. As warranted, other options may be considered on a joint basis. For example, an upgrade of the 230 kV system to 345 kV throughout the New York North Country and conversion of any new interconnections to 345 kV could be considered as an ultimate transmission plan for this area. Alternatively, NYISO and ISO-NE are working with a merchant developer that is considering a new tie between the New York North Country and Vermont.

10.3 Transmission Cost Allocation

Historically, the Federal Energy Regulatory Commission (FERC or the Commission) has pursued a logical and progressive policy of establishing planning processes and cost allocation provisions for jurisdictional transmission providers, including ISOs and RTOs. Order 888, which first posed the concept of an Independent System Operator to ensure comparable access to the transmission system, did not have any specific planning requirements for such entities. Order 2000 required applicants that would voluntarily request RTO status to include in their tariffs provisions for planning to ensure reliability—recognizing the critical importance of ensuring a reliable bulk power supply system. Planning for economic purposes, including cost allocation provisions, have been addressed by the Commission in the context of individual RTO proceedings to provide information to market participants regarding potential economic opportunities. The Commission now requires, pursuant to Order 890, that all jurisdictional transmission providers have formal planning processes in their respective tariffs which include both economic and reliability planning as well as cost allocation provisions for each. At this time, all ISOs/RTOs now have FERC-accepted planning and cost allocation processes in their respective tariffs.

Thus far, the Commission has also addressed inter-regional cost allocation only between the MISO and PJM, and then only after having approved the intra-regional cost allocation procedures for those respective regions. However, in its Notice of Request for Comments in Docket AD09-8, FERC staff queries whether the Commission should pursue generic reform in the area of cost allocation or should continue to address interregional cost allocation on a case-by-case basis.

Status of Order 890

Order 890 proposed nine planning principles that all transmission providers were required to meet in the development of their respective planning processes: coordination, openness, transparency, information exchange, comparability, dispute resolution, cost allocation, economic studies and regional participation. Since the Commission directed each ISO/RTO to develop the specifics of their proposals with their respective stakeholders and to recognize regional needs. The result is that, while similar, there are differences in the approaches employed by each region. These differences are evidenced in both the planning provisions and their associated cost allocation provisions. A summary of the cost allocation provisions of all ISOs and RTOs can be found in the appendix.

It should be noted that while cost allocation provisions for reliability projects have been in place in some regions for many years, application of economic cost allocation provisions varies from region to region. PJM has in place FERC approved market efficiency planning provisions applicable to PJM's regional planning RTEP process as well as PJM's interregional planning with the Midwest ISO. In two orders issued on October 15, 2009, FERC approved the NYISO's economic planning and cost allocation methodology as part of its Order 890 compliance filings, rejecting the remaining protests. The NYISO expects to receive Board approval of its first economic planning Phase I report by January 2010. ISO-NE has economic cost allocation provisions in its tariff and the New England region continues to work on various methods of economic transmission as may be appropriate.

It is also important to understand the differences in the approach to cost allocation that have been developed by each of the ISOs/RTOs in conjunction with their stakeholders and state agencies before proceeding with discussions concerning inter-regional cost allocation. The approach taken by PJM and MISO in the development of inter-regional cost allocation for reliability projects and market efficiency projects started with a comparison of their respective regional approaches. The PJM and MISO interregional planning was the result of a FERC directive with its origin in the PJM/MISO Seams Elimination Cost Adjustment ("SECA") proceeding in 2004. Now that their respective individual cost allocation procedures have been substantially finalized by the Commission, NYISO and PJM plan to begin discussions regarding cross-border cost allocation following completion of the planning studies outlined in Section **Error! Reference source not found.**. Further stakeholder discussions will be conducted in an open and transparent process, including stakeholders in both regions.

ISO-NE will continue to work with its stakeholders and other regions on cross border cost allocation for specific projects that have been identified for consideration.

11 Summary and Conclusions

11.1 Summary

The studies and activities covered in this report demonstrate that considerable proactive interregional planning is being performed by ISO New England, NYISO and PJM, especially under the joint protocol.

The ISO/RTOs develop their system plans, conduct economic studies, and perform interconnection studies accounting for the modeling of neighboring regions and interregional system performance. The ISO/RTOs planning efforts have resulted in the addition of new transmission ties between the regions and the integration of new generator interconnections near the border areas. The Loss of Source (LOS) limits on interregional transfers are now considered a usual part of planning studies and account for the effects of major new transmission upgrades and ties between the ISO/RTOs. With the addition of the planned 500 kV and 765 kV lines within PJM, past LOS analysis confirmed that these additions will result in a LOS limit in the 1,400 MW to 1,500 MW range. Related to wind development in the New York North Country and other system needs in both New York and Vermont, a Plattsburgh - Vermont tie study was completed. This study demonstrated the feasibility of addressing reliability issues in the ISO-NE system and potential reliability issues with increased wind energy production in the NYISO system, while also increasing the transfer limits between New York and Vermont along with high LOS limits. Reliability analysis of the NYISO/PJM interface located between Southeast New York (SENY) and Northern Public Service, New Jersey, demonstrate sufficient transfer limits into the areas to meet resource adequacy and deliverability criteria. Market efficiency analyses have been initiated and assumptions have been shared with the IPSAC. Results of simulations of the SENY and Northern Public Service areas benchmark well with current market conditions and areas of improved modeling have been identified.

In addition to studies conducted under the Protocol, several major interregional planning activities are supported by ISO-NE, NYISO, and PJM. These include the coordination of data bases and planning studies conducted by the Regional Reliability Councils and NERC that ensure interregional reliability. The newly formed EIPC holds the promise of interconnection-wide planning through an open stakeholder process. The ISO/RTOs have also addressed fuel diversity issues resulting in improved interregional operation of the overall system.

Emerging environmental issues are important and can affect the reliability of the system as large numbers of generators could become affected by regulations. Key environmental issues include the attainment of ozone standards, greenhouse gas reductions (particularly CO2), and power plant cooling water impacts. These will affect the future economics of power plants by adding costs for emission allowances, requiring use of low emitting fuels, and adding capital costs for controls. Restrictions in power plant energy production and reduced capacity output could adversely affect reliability. The ISO/RTOs will continue to monitor and evaluate the effects of environmental regulations on the power system.

The JIPC summarized the Renewable Portfolio Standards for the entire region and compared them with projects in the Interconnection Queues. RPS will be met by project development on the transmission lower voltage systems, reduced load energy consumption, and alternative compliance payments that also serve as a cap on the price that loads would need to pay for renewable resources. Large expansion of renewable resources could necessitate new transmission development within and between the regions, including Canada.

Because of the potential of large growth of wind energy throughout the Northeast, much analysis is being done by the three ISO/RTOs, individually and collectively, to address wind integration issues. The total region of the three ISO/RTOs has over 55,000 MW of wind projects in their combined queues of which over 90% is onshore wind. In addition, the proximity of the Northeast to neighboring Canadian provinces that are developing hydro and wind projects may provide additional opportunities to supply the ISO/RTOs with renewable sources of energy. The technical issues surrounding wind integration have been shared by the ISO/RTOs and several studies are on track to fully address the issues.

Demand side resources participate in the ISO/RTO markets in a manner comparable to generation resources. DSRs may reduce the need to build physical infrastructure, but the large presence of DSRs in the system also creates integration and reliability issues that are being addressed by the ISO/RTOs.
As each ISO/RTO adds new resources and transmission to meet their own load growth and system development needs, these changes can affect the transfer of power among them and interregional system performance, thereby justifying further interregional analysis. Recognizing this and the need to further enhance interregional planning efforts, the ISO/RTOs have completed and initiated a number of technical studies. Market efficiency analyses are being conducted to identify possible transmission bottlenecks. Once identified, the JIPC will conduct more detailed transmission analysis and production cost studies. The ISO/RTOs are committed to discussing interregional cost allocation as may be required for individual projects. The ISO/RTOs regularly provide the status of seams issues including the schedules for addressing the planning issues and studies identified in this report.

11.2 Conclusions

Progress has been made proactively planning the interregional system under the Northeastern ISO/RTO Planning Coordination Protocol by ISO-NE, NYISO and PJM. The Joint ISO/RTO Planning Committee has coordinated and planned resource adequacy, production cost, and transmission planning studies. The scope of work, assumptions, and review of draft study results are subject to open stakeholder review provided by the IPSAC. The desirability of performing specific studies and the need to address several issues have been identified and their status will be discussed at future stakeholder meetings.

While much has been accomplished under the protocol over the past several years, both the ISO/RTOs and their stakeholders recognize that much remains to be done to further advance and enhance inter-regional planning for the Northeast and beyond. The efficiencies to be gained by trading electric power capacity and energy with other systems will most likely become even more advantageous over time. Such enhanced capabilities will also facilitate meeting RPS requirements, reduce CO_2 and NOx emissions, and meet other environmental requirements. Providing better access to generation resources that use a wide variety of fuels will improve the overall reliability and economic operation of the Northeast bulk power system. For all these reasons, a robust inter-regional planning process is essential. The Northeast ISO/RTOs are committed to the advancement of this process, in collaboration with their stakeholders.

12 Appendices

12.1 Cost Allocation Matrix of the ISO/RTOs

This section provides a summary of the cost allocation methods of the ISO/RTOs PJM, SPP, MISO, NYISO, ISONE, ERCOT, and CALISO.

PJM	PJM -- Cost Allocation Philosophies and Practices	
	EXISTING	**UNDER CONSIDERATION**

Reliability Upgrades	▪ **RTEP baseline facilities at or above 500 kV voltage level**
	- Also includes costs of those related facilities below 500 kV needed to support a 500 kV upgrade.
	- Considered "Regional Facilities" by FERC – region-wide allocation
	- Load ratio share at time of EACH ZONE's annual peak of previous year ending October 30
	- Merchant transmission share based on firm transmission withdrawal rights, per respective Interconnection Service Agreements.
	
	▪ **Baseline BELOW 500 kV…**allocation process pending before FERC with respect only to appropriate allocation to merchant transmission exports
	- General
	  - If cost estimate < $5 million, costs allocated to zone where upgrade is required
	  - If cost estimate >= $5 million, costs allocated based on distribution factor (DFAX) analysis; DFAX percentages based on zonal load and merchant transmission firm withdrawal rights
	- Lines, Transformers, etc.
	  - Allocate based on impact of each TO zone on the constrained facility, i.e. (change in power flow due to that TO zone) / total power shift on constrained facility)
	- Circuit Breakers (CBs)
	  - If need associated with a planned transmission upgrade, allocate CB cost as part of that upgrade;
	  - If need is independent of any other planned transmission system upgrade, cost allocated to zone in which CB is located
	
	▪ **PJM / MISO Cross-border**
	- Transfer distribution factor (DFAX) analysis to calculate each RTO's flows affecting a constrained facility that a proposed cross-border facility is to relieve
	- Total net flow of each RTO on a constrained facility, i.e. (all positive flow) less (all counterflow)
	- After cross-border facility costs are allocated to each RTO, each RTO then allocates internally according to its own OATT.
		▪ **Baseline BELOW 500 kV for cost assignment to merchant transmission**
		- Cost assignment for reliability upgrades awaiting FERC action in pending dockets
		  - Merchant transmission developers believe that they should either have no cost allocation for future transmission system upgrades or that they should only have allocations for upgrades that are not related to load growth
		  - Other parties believe that allocations to merchants should be based on firm withdrawal rights specified in ISAs

PJM	PJM -- Cost Allocation Philosophies and Practices	
	EXISTING	**UNDER CONSIDERATION**
Economic Upgrades	▪ **AT OR ABOVE 500 kV** - Load ratio share at time of EACH ZONE's annual peak of previous year ending October 30 - Merchant transmission share based on firm transmission withdrawal rights, per respective ISAs. ▪ **BELOW 500 kV, modifications to reliability upgrades already in RTEP** - Cost allocation based on distribution factor methodology, as discussed above ▪ **BELOW 500 kV, accelerated reliability upgrades already in RTEP.** - Compare allocation factors based on: [1] DFAX; [2] LMP benefit over acceleration period based on load payments by LSEs; if differential >= 10%, use relative LMP benefit; otherwise, use DFAX methodology	▪ **BELOW 500 kV, ECONOMIC ONLY.** - FERC, per a 7/29/08 order, required parties to file a methodology within one year ▪ **BELOW 500 kV for cost assignment to merchant transmission.** - Cost assignment for economic upgrades awaiting FERC action in pending dockets order

SPP	SPP -- Cost Allocation Philosophies and Practices	
	EXISTING	**UNDER CONSIDERATION**
Reliability Upgrades	▪ **All voltage levels, upgrade cost > $100,000…** - 1/3 of revenue requirement for upgrade is allocated regionally via postage stamp rate. [per SPP OATT, Attachment J] - 2/3 allocated to zones based on each zone's share of incremental positive MW-mile benefits…yielding Base Plan Zonal Annual Transmission Revenue Requirement (BPZATRR), [per SPP OATT, Schedule 11] - Each network load customer and TO charged - (1/12) x (zonal load ratio share) x (BPZATRR)	

<table>
<tr><th rowspan="2">SPP</th><th colspan="2">SPP -- Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING</th><th>UNDER CONSIDERATION</th></tr>
<tr><td>Economic Upgrades</td><td>All voltage levels. Paid by the project sponsor. The sponsor is provided revenue credits for subsequent service SPP is able to sell because of the upgrades.</td><td>[Subject of pending August 15, 2008 SPP FERC filing.]
345 kV voltage level and above and certain lower voltage facilities under specific conditions…Region-wide cost allocation via postage stamp rate for economic upgrades if part of a balanced portfolio of economic upgrades (vs. project by project assessment of benefit).

<u>Balanced Portfolio of Economic Upgrades</u>
- Balanced means a benefits/costs ratio >= 1.0, using adjusted production cost for determination of benefits.
- Adjusted Production Cost = Production Cost + Purchases - Sales
- Ten-year present value of zonal benefit should not be less than levelized revenue requirement via region-wide postage stamp rate.

<u>If a balanced portfolio of economic upgrades cannot be found…</u>
- Costs assigned to zones that are deficient in benefits removed from calculation of zonal rate and added to region-wide postage stamp rate to balance costs and benefits. Helps to equalize economic capability across SPP footprint without charging more highly developed portions of the system with the cost of upgrades for less developed portions. More costs can be collected through a region-wide rate, less via zonal license plate rates. If all zones are currently at the same level of development, SPP is likely to develop a balanced portfolio based solely on transmission upgrades and, thus, transfers are not likely to be needed to provide balance.
- Production cost savings offset transmission rates paid by load. Profits that would otherwise be captured as a result of increased sales vis-à-vis increased transmission rates are refunded/credited back to load.
- No customers in SPP's footprint have retail choice at this date, or in the foreseeable future. The Balanced Portfolio allows each pricing zone and each state to claim a positive benefit, a significant political point. No requirement for a Balanced Portfolio each year. In a given year, should the cost become too great or not enough projects found then the year is simply skipped. The policy decision on the balanced portfolio was determined by SPP’s Regional State Committee (RSC) through a stakeholder process</td></tr>
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<table>
<tr><th rowspan="2">MISO</th><th colspan="2">MISO -- Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING</th><th>UNDER CONSIDERATION</th></tr>
<tr><td>Reliability Upgrades</td><td>

Baseline Reliability Projects (BRPs) >= 345 kV: 20% per Postage Stamp based on load ratio shares; remaining 80% based on Line outage Distribution Factor (LODF) calculation methodology used for sub-regional allocations.
Baseline Reliability Projects of 100 kV to 344 kV: 100% of eligible cost is allocated to pricing zones based on LODF in terms of [LODF] x [Miles]. Sub-regional percentage share for a given pricing zone is calculated as the relative zonal share of sum of absolute values.
Generation Interconnection Project cost of network upgrades:

50% based on the same sub-regional and/or postage stamp allocation rules applicable for BRPs; remaining 50% assigned to the Interconnection Customer
Interconnecting to American Transmission Company, International Transmission Company, Michigan Electric or ITC Midwest pricing zones: 50% to pricing zone; 50% to affected pricing zones based on sub-regional and/or postage-stamp allocation rules

Transmission Delivery Service Projects: needed for new Point-To-Point Transmission Service, or new Network Resource designation…assigned to transmission customer until appropriate regulatory authority permits roll-in to existing transmission rates
PJM / MISO Cross-border: transfer distribution factor (DFAX) analysis to calculate impact of each RTO's flows on constraint, based on Total Net Flow.

Total net flow of each RTO on a constraint = (all positive flow) less (all counterflow)
After allocation to each RTO, each RTO then allocates according to its own OATT.

</td><td>
[No modifications presently under consideration.]</td></tr>
<tr><td>Economic Upgrades</td><td>

"Regionally Beneficial Projects" (RBPs):

20% allocated on a system-wide rate to all transmission customers;
80% allocated to three defined sub-regions based on relative "weighted-gain-no-loss" value of positive present value of annual benefits…

70% weighted on adjusted production cost changes
30% on Locational Marginal Price (LMP) changes.

"Cost" eligibility: >= $5 million
"Voltage" threshold: >= 345 kV; and those under 345 kV needed to achieve benefit of associated upgrades over 345 kV
"Benefit" Eligibility for regional cost allocation: (1) Present Value of annual benefits > 0; (2) minimum specified benefit/cost ratio met based on in-service date…

Within 1 year…1.2 : 1, Within 2 years 1.4 : 1
Within 3 years…1.6 :1, Within 4 years 1.8 : 1
Within 5 years…2.0 : 1, increasingly linearly up to 3.0 : 1 within 10 years

</td><td>
"…as experience with [RBPs] and additional value driver analytics mature, tariff filings to adjust or amplify the inclusion criteria and minimum benefits threshold are expected…additional value drivers might include generation reserve margin considerations, fuel diversity considerations, reliability considerations and national and state energy policy goals, and risks to implementation to name some that warrant consideration."</td></tr>
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<table>
<tr><th rowspan="2">NYISO</th><th colspan="2">NYISO -- Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING</th><th>UNDER CONSIDERATION</th></tr>
<tr><td>Reliability Upgrades</td><td>
▪ NYISO "all source" planning process
- Reliability needs identified; solutions from marketplace solicited; transmission, generation and demand response on a level playing field
- NYISO evaluates all proposed solutions against needs but does not pick any specific solution; explicit preference is given to market-based solutions
- Regulated backstop solutions, provided by TOs, can be triggered if market-based solutions are not available
- NYPSC reviews regulated backstops and alternative regulated proposals and determines which should go forward
- Cost allocation philosophy…beneficiary pays

▪ Regulated Reliability Transmission Projects: Applicable to projects triggered prior to 1/1/2016, after which NYISO to propose continuation or another alternative approach. NYISO uses a 3-step approach based on scope of area that has requirement for installed capacity: (1) Locational Need; (2) Statewide need; (3) Bounded Region / Constrained Interface Need. Based on a 1-day-in-10-years loss-of-load-expectation standard and beneficiary pays principle;
1. <u>Locational Need:</u> i.e., NYC and Long Island - 100% of costs allocated to LSEs in respective zone(s). Then, Step 2.
2. <u>Statewide Need:</u> i.e., New York Control Area - reliability upgrades necessary to bring control area to 1-day-in-10 reliability, under UNCONSTRAINED system, i.e., all transmission constraints relaxed; allocation to all load zones in control area based on load ratio share of control area coincident peak; zonal credits for meeting locational capacity requirements where locational upgrade cost allocation offsets statewide reliability upgrade cost allocation. If Step 2 is invoked - i.e., upgrades triggered under this test – then methodology stops with this Step; otherwise move on to Step 3
3. <u>Bounded Region / Constrained Interface Need</u>: determine zones with binding interfaces, preventing sufficient capacity from being deliverable throughout the control area; "compensatory MW" added to bounded region based on greatest LOLE impact to reach 1-day-in-10 standard; successive iterations run until 1-day-in-10 is achieved across control area; compensatory MW are allocated to zones within a bounded region based on zonal contribution to control area coincident peak; <u>"compensatory MW"</u> are resources required to fulfill identified need and can be transmission, generation and/or demand response solutions.
</td><td>▪ [No modifications presently under consideration]</td></tr>
</table>

<table>
<tr><th rowspan="2">NYISO</th><th colspan="2">NYISO -- Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING</th><th>UNDER CONSIDERATION</th></tr>
<tr><td></td><td>Regulated Reliability NON-TRANSMISSION Projects: “Costs…will be recovered by [Transmission Owners] and other developers in accordance with the provisions of …state law. On June 26, 2009, the New York State Public Service Commission revised its previously adopted Policy Statement to adopt the FERC-approved transmission cost allocation methodology for non-transmission regulated reliability projects to ensure that all solutions are considered on an equal basis.</td><td></td></tr>
<tr><td>Economic Upgrades</td><td>Current planning process includes a procedure for analysis and posting of historic congestion information to assist stakeholders in developing resource plans
NYISO Congestion Assessment and Resource Integration Study (“CARIS”):
- Phase I - Study Phase: ISO analyzes potential generic solutions to congestion over a 10-year period based upon the top three groupings of congested facilities prioritized in consultation with NYISO stakeholders. Studies consider all resources as potential solutions. Threshold based upon statewide production cost savings compared to total estimated project revenue requirement over ten years. NYISO will also calculate zonal locational marginal cost based savings, losses, transmission congestion contracts and other metrics.
- Phase II – Specific Project Phase: Upon request, ISO analyzes specific economic transmission projects proposed by developers for consideration for cost recovery under the NYISO tariff. Eligibility threshold based upon statewide production cost savings compared to the total estimated project revenue requirements (provided by the developer) over the first ten years of the project’s operation. Cost of regulated economic transmission projects allocated to load based on zonal share of total LMP savings for those zones with savings. At least 80% of beneficiaries must vote in favor of the project in order to be eligible to receive regulated recovery under the NYISO tariff. Developer must file revenue requirements with FERC upon completion of project.
-</td><td>[No modifications presently under consideration.]</td></tr>
</table>

<table>
<tr><th rowspan="2">ISO-NE</th><th colspan="2">ISO-NE -- Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING
[…on or after January 1, 2004, per ISO-NE Open Access Transmission Tariff]</th><th>UNDER CONSIDERATION</th></tr>
<tr><td>Reliability Upgrades</td><td>
▪ Reliability Benefit Upgrades (RBU):
- 115 kV or above;
- Meet definition of Pool Transmission Facilities (“PTF”); and
- Be included in Regional System Plan as either a Reliability Transmission Upgrade (RTU) or a Market Efficiency Transmission Upgrade (METU).

▪ RBUs are eligible for regional cost recovery as part of “Pool-Supported PTF costs”
- Must meet PTF definition based on ISO review of transmission plans submitted by market participants and TOs;
- ISO determines Localized Costs – “the costs of transmission upgrades that exceed reasonable requirements . . . shall be deemed Localized Costs.” Localized Costs are not included in the Pool-Supported PTF costs. Determination based on ISO assessment of proposed engineering design and construction methods and practices, alternative upgrades, allowance for expansion and load growth, as well as relative costs, timing, implementation, efficiency and reliability of proposed upgrades.
- Pool-Supported PTF costs (i.e., those not localized) are allocated region-wide.

▪ RTUs: are those “…upgrades necessary to ensure the continued reliability of the New England Transmission System based on applicable reliability standards.”
</td><td>▪ [No modifications presently under consideration.]</td></tr>
<tr><td>Economic Upgrades</td><td>
▪ Market Efficiency Transmission Upgrade (METU) “upgrades designed primarily to provide a net reduction in total production cost to supply the system load.” “[D]esigned to reduce bulk power system costs to load system-wide; …net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade; …“bulk power system costs to load system-wide” includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.”
- METU costs that meet RBU criteria are included in the Pool-Supported Costs.
- METUs that are not RBUSs are not included in the Pool-Supported PTF Costs.
- By definition, neither METUs nor RBUs are “related to the interconnection of a generator,” unless determined otherwise under Schedule 11.
</td><td>▪ [No modifications presently under consideration.]</td></tr>
</table>

ERCOT	ERCOT -- Cost Allocation Philosophies and Practices	
	EXISTING	**UNDER CONSIDERATION**
Reliability Upgrades	▪ Costs allocated regionally to load and to power exports from ERCOT region, based on load-ratio share. ▪ Reliability upgrades include those to mitigate constraints both between and within established ERCOT sub-regions ▪ Specific transmission system improvements are evaluated for projected longer-term problems on the 345 kV network. ▪ Lines ordered as a result of the state's recently legislated Competitive Renewable Energy Zone (CREZ) process may supersede these projects.	▪ [No modifications presently under consideration.]
Economic Upgrades	▪ In addition to identified reliability upgrades, significant uneconomic congestion would be experienced if these were the only improvements and upgrades implemented. ERCOT also identifies congested system elements and evaluate upgrades that would be economic in reducing the energy production cost for the system by relieving these congested elements. - Costs for such upgrades are also allocated regionally to load and to power exports from ERCOT region based on load-ratio share. - Lines ordered as a result of the state's recently legislated Competitive Renewable Energy Zone (CREZ) process may supersede these projects.	▪ [No modifications presently under consideration.]

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<tr><th rowspan="2">Cal-ISO</th><th colspan="2">Cal-ISO -- Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING</th><th>UNDER CONSIDERATION</th></tr>
<tr><td>Reliability Upgrades</td><td>▪ For need as determined by the ISO for the following types of proposed transmission additions or upgrades, cost is borne by each Participating TO and reflected in its Transmission Revenue Requirement:
- Reliability driven projects
- Economically driven projects
- Long-term congestion revenue rights feasibility

▪ Costs recovered via Participating Transmission Owners (PTOs) revenue requirement through ISO administered charges; facilities at 200 kV and above:
- Transmission Access Charge (TAC) -- paid by Load Serving Entities based on pro-rata load share.
- Wheeling Access Charge (WAC) -- paid for transactions wheeled Out or Through ISO.

▪ Location Constrained Resource Interconnection Facility (LCRIF)… transmission projects to connect generators in designated transmission constrained areas; PTOs finance up-front costs; costs associated with the unsubscribed portion of the LCRIF will be included in TAC, until additional generators are interconnected, at which time costs will be assigned to such generators going forward on a pro-rata basis.</td><td>▪ [No modifications presently under consideration.]</td></tr>
<tr><td>Economic Upgrades</td><td>▪ Economic Transmission Project proposals: include upgrades or additions proposed to reduce Local Capacity Area Resource requirements, reduce or eliminate Congestion, or Merchant Transmission Facilities to obtain Merchant Transmission Congestion Revenue Rights. Costs are recovered per the process described above for reliability upgrades.

▪ Merchant Transmission Facility: a transmission addition or upgrade whose costs are paid by a Project Sponsor that does not recover the cost of the transmission investment through the TAC or WAC or other regulatory cost recovery mechanism. Rather than obtain a recovery of costs through a regulated rate, the Project Sponsor of the Merchant Transmission Facility obtains Merchant Congestion Revenue Rights</td><td>▪ [No modifications presently under consideration.]</td></tr>
</table>

12.2 References

An early 2008 update on the activities of the Northeast International Committee on Energy (NICE) can be found at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/mar192008/a_nice_update.pdf, which provides an initial summary of proposed new resource development in New England and eastern Canada. The follow up presentations made to the New England Governors and eastern Canadian Premiers in September 2008 can be found at http://www.iso-ne.com/pubs/pubcomm/pres_spchs/index.html.

The Joint Coordinated System Plan (JCSP) is evaluating scenarios of large wind development primarily in the Midwest and transmission alternatives for delivery of the energy mostly to the Northeastern U.S. Materials can be found at http://jcspstudy.org/.

PJM has published a paper on transmission cost allocation, available at http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2010/feb22010/tca.pdf.

The New Brunswick System Operator (NBSO) has issued a report entitled: The Electric Power System in New Brunswick. A Discussion Paper on Potential Generation and Transmission Developments, December 2008 found at: http://www.nbso.ca/Public/_private/NBSO%20Discussion%20Paper%20Final%20Pre-release%20Dec%2012,%2020.pdf

Information on the Northeast Power Coordinating Council (NPCC) can be found at: http://www.npcc.org/

NPCC has also posted a report entitled "Modeling Wind Resources in Resource Adequacy Assessments," http://www.npcc.org/documents/publications/Other.aspx.

Information on ERAG can be found at the following links: http://www.erag.info, https://www.npcc.org/interReg/ERAG.aspx and https://www.npcc.org/interReg/reliabilityFirst.aspx

The Inter-Area Planning Stakeholder Advisory Committee (IPSAC) is an open stakeholder group that supports the comprehensive interregional planning process implemented under the Northeastern ISO/RTO Planning Coordination Protocol ("Protocol") by ISO-NE, NYISO and PJM. The IPSAC has discussed the Northeast Coordinated System Plan including interregional projects and cost allocation issues.

Background IPSAC Materials are posted on the public-domain IPSAC site: http://www.interiso.com/default.cfm.

For ISO-New England stakeholders:

Materials for the IPSAC meetings are posted on the password-protected IPSAC site: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/index.html.

Access to the IPSAC is the same as for password-protected PAC materials. If you do not have access to the protected ISO-NE IPSAC site, please contact the ISO's Customer Service Department at 4135404220 or custserv@iso-ne.com to request access.

For PJM stakeholders:

Materials for the IPSAC meetings are posted at: http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/ipsag.aspx.

For NYISO stakeholders:

Materials for the IPSAC meetings are posted at:
http://www.nyiso.com/public/committees/documents.jsp?com=oc_ipsac.

If you do not have access to the protected NYISO IPSAC site, please contact the NYISO Customer Service Department at (518) 356-6060 or http://www.nyiso.com/public/services/customer_relations/index.jsp.