ISO/RTO Electric System Planning

Current Practices, Expansion Plans and Planning Issues

A Report Prepared by the ISO/RTO Planning Committee

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INTRODUCTION AND BACKGROUND

In April 2003, the nine functioning independent system operators (ISOs) and regional transmission organizations (RTOs) in North America formed the ISO/RTO Council (IRC). The current members of the IRC are the Alberta Electric System Operator (AESO), the California Independent System Operator (CAL-ISO), the Electric Reliability Council of Texas (ERCOT), the Independent System Operator of the Province of Ontario (IESO), Independent System Operator of New England (ISO-NE), the Midwest Independent System Operator (Midwest ISO), the New York Independent System Operator (NYISO), the PJM Interconnection (PJM), and the Southwest Power Pool (SPP). The IRC's mission is to work collaboratively to develop effective processes, tools, and standard methods for improving competitive electricity markets across North America. To fulfill this mission, the IRC aims to provide a perspective that balances reliability standards and market practices, so that neither has an undue impact on the other and the resulting markets are efficient, robust, and provide competitive and reliable service to customers. This is the report of the IRC's Planning Committee, which is one of the several committees that comprise the IRC.

IRC Planning Committee

The ISO/RTO Council Planning Committee (IRC PC) promotes communication and assists in coordinating issues of mutual concern that affect ISO/RTO planning in the electricity industry. The IRC PC furthers the goals and purposes of the IRC by facilitating interactions among the ISOs/RTOs, providing a means to collaborate and identifying ways for the ISO/RTO entities to coordinate system planning activities. The PC performs the following activities to coordinate ISO and RTO electricity market and system operation planning in North America:

i. Shares expertise and advice on system planning functions, practices, and activities underway within the wholesale electricity industry in North America.

ii. Develops consensus positions on significant regulatory policy proposals to effectively integrate regulatory policy direction into ISO/RTO planning activities.

iii. Identifies viable recommendations concerning the relationship between market rules and policies and system planning practices and the standardization of system planning practices within the electricity industry in North America.

iv. Coordinates and builds consensus positions on system planning recommendations and standards-setting activities in standards-making organizations, such as the North American Reliability Council (NERC).

v. Coordinates and exchanges data and information on planning issues, which can include FERC filings, NERC issues, planning criteria, and planning models.

vi. Collaborates on other activities as appropriate to fulfill the purpose and goals of the IRC PC Charter and the ISO/RTO Council Charter.

Report Objectives and Organization

The objectives of this report are to document the status of ISO/RTO planning; summarize the current ISO/RTO system plans; and report on system planning practices and issues, such as reliability planning, economic planning, deliverability of capacity, resource adequacy, generator interconnection, including the impact of wind generators, and the potential impact of increasing dependence on natural gas for the generation of electricity. The report begins with an Executive Summary followed by a series of reports by each ISO/RTO. Report I of this document is a report by each ISO/RTO, which provides an overview of the current state of electricity system planning practices and processes for each ISO/RTO footprint. Report II is a summary of current ISO/RTO system plans, and Report III is a review of the ISO/RTO mechanisms designed and developed to address interregional coordination.

EXECUTIVE SUMMARY

This executive summary provides an overview of the report, followed by summaries of the information contained in the individual ISO/RTO reports and a conclusion of the overall findings of this report. The summaries cover the current state of ISO/RTO electric system planning processes, the current ISO/RTO system expansion plans, the ISO/RTO mechanisms designed and developed to address interregional coordination, and some of the common issues facing the ISO/RTOs.

REPORT OVERVIEW

ISO/RTOs conduct long-term regional planning to identify system upgrade and expansion needs for reliability and, increasingly, for economic benefit. Unlike stand-alone utilities, which look at reliability needs only within their borders, ISO/RTOs look at the needs across all of the utilities and loads within their borders and are exploring opportunities for inter-regional benefit. Closely related to the long-term regional planning process, ISO/RTOs manage the analytical and administrative processes of generation interconnection. This entails receiving interconnection requests, conducting impartial, expeditious technical analyses of the impact of each generator individually and in groups, interconnecting to the grid, and determining and allocating the costs of new transmission construction to connect the new generator to the bulk power system.

ISO/RTOs coordinate their planning activities with neighboring areas. Because RTOs and ISOs serve a broad region and include a broad set of stakeholders from the region in the planning process, they can explore a breadth of alternatives to address the reliability problems or economic opportunities identified. This improves the effectiveness of regional system planning and assures that the chosen outcomes will be cost-effective as well as widely accepted and understood. And by identifying system expansion opportunities in advance of the need, the planning process gives market participants time to assess the alternatives and propose either a market-based solution (e.g., a merchant transmission line, power plant, or demand response) or regulated solution (e.g., a rate-based transmission line).

Regional electric system planning is evolving. In the early days of an ISO/RTO planning effort, transmission expansion plans often represented a compilation of the member utilities' local transmission plans. As the planning organization and stakeholder relationships grow stronger, the plans grow in scope and complexity, starting with work to conduct reliability planning on an intraregional basis and then moving to interregional reliability and economic or environmental improvement projects. Often, the next step is to strengthen the plan to address a particular system need or policy issue that exceeds reliability alone. After the RTO's planners and transmission owners become comfortable with regionally integrated reliability planning, the next step is to look at intraregional and interregional economic opportunities, where new transmission investment can significantly increase interregional flows and reduce costs.

SUMMARY OF ISO/RTO PLANNING PROCESSES

This section presents a brief overview of the planning processes for the IRC Members, with a more detailed report by each ISO/RTO contained in ISO/RTO Report I.

While the IRC members have different statutory authorities, the members have many planning responsibilities in common. This commonality is primarily the result of the fundamental need to independently and fairly administer the needs of all market participants, including developers of generation, transmission, and distributed resources (DR). The ISO/RTOs lead all planning efforts and thus ensure a level playing field for the development of infrastructure efficiently driven by competition while meeting all reliability requirements.

All ISO/RTOs assess system resource adequacy and transmission adequacy, which provides vital information to the markets. Studies identify the need for infrastructure improvements, which could include new resources or transmission upgrades. These infrastructure improvements maintain reliability and support competitive markets. Most ISO/RTOs also conduct tariff studies necessary for generator interconnections or other transmission service requests. The independence of the ISO/RTO structure ensures that each ISO/RTO impartially evaluates resource, transmission, or combined solutions to identified system problems. The ISO/RTO respect for market confidentiality allows for the interconnection of all types of resources.

The overall system expansion plans are coordinated with the ISO/RTO participants as well as with neighboring areas. The IRC members have all registered as NERC planning authorities and are active members in their Regional Reliability Councils, which in some cases are the same as the ISO/RTO.

The IRC members all seek open stakeholder input into their planning processes. This open planning process provides vital information to market participants, state or provincial, as well as local governmental authorities, and other interested parties, such as consultants and manufactures. Communication and collaboration between developers, transmission owners, and the regulatory community have facilitated the development of optimal plans that are more widely accepted.

For each ISO/RTO, the stakeholders review the scope of work and draft study results. The ISO/RTO evaluates the proposals for generation, merchant and elective transmission, and demand-side solutions as possible market responses to system problems. The evaluation includes a “reality check” to ensure that the market response will likely be in service in a timely manner. To protect against a failure of the market to adequately respond, the ISO/RTO leads a transmission planning effort that serves as a backstop to the market responses. The transmission plan may consider system reliability, congestion, fuel diversity, environmental emissions, and other factors.

SUMMARY ISO/RTO PLANS

This section presents a summary of the electric system expansion plans for IRC Members, while more detailed reports of the individual plans appear in ISO/RTO Report II.

Two-thirds of the United States population lives in regions served by Regional Transmission Organizations and Independent System Operators. In 2004, ISO/RTOs delivered 2.4 million GWh of electricity—62% of the electricity consumed in the U.S. and 58% of the peak load. They oversee more than 272,000 miles of high-voltage transmission lines and coordinate power production from 585,000 MW of generation (67% of the U.S. total).

The restructuring of the electric utility industry, along with the associated financial uncertainties of new markets and divestiture, resulted in an initial lack of investment in grid infrastructure. However, the formation of ISOs and RTOs with planning responsibilities has resulted in the identification of needed system expansion projects. The ISO/RTO planning process works and is getting the needed infrastructure in place. Below is a summary of system expansion, resource development and investment activity for each ISO/RTO footprint.

AESO

The Alberta Electric System Operator (AESO) is Canada's first customer-focused exchange for electricity and officially went into operation on June 1, 2003. As the independent system operator it leads the safe, reliable and economic operation and planning of Alberta's interconnected transmission system. The AESO also facilitates Alberta's competitive wholesale electricity market, which has more than 200 participants and about Cdn $5 billion in annual energy transactions, and is accountable for the administration and regulation of the load settlement function. Since its creation in 2003 the AESO has received regulatory approval for approximately 80 transmission projects, which will result in the addition of approximately 330 kilometres (200 miles) of new 500 kV, 580 kilometres (350 miles) of new 240 kV and 200 kilometres (120 miles) of new 138/144 kV transmission line. During this same period approximately 1345 MW of new generation has been added to the Alberta system. As the transmission planning authority for the region, the AESO works closely and collaboratively with its many stakeholders to provide open and non-discriminatory access to the Alberta transmission system.

CAL-ISO

Over the five year period between 2000 through 2004, the California ISO authorized 237 transmission project upgrades representing $2.4 Billion of infrastructure investment. $1.8 Billion of transmission projects were completed during that time period. Over 10,000 MW of new generation projects and 2500 MW of demand response were added in California during the same time period. As the transmission planning authority for the region, the California ISO works closely with its Participating Transmission Owners, California Public Utilities Commission, California Energy Commission and its other stakeholders to proactively identify needed, cost effective transmission solutions through an open, non-discriminatory planning process.

ERCOT

Since 1999, over 4,400 circuit miles of transmission lines and 24,600 MVA of autotransformer capacity have been added in ERCOT. The estimated capital cost of these transmission improvements is approximately $2.2 billion. 59 power plants totaling 24,000 MW were added in ERCOT during the same time period. Approximately 3,750 miles of new transmission and 23,600 MVA of new autotransformer capacity have been identified over the next six years with a cost of $2.8 billion. As the transmission planning authority for the region, ERCOT works closely with its stakeholders to identify cost effective transmission solutions through an open, non-discriminatory planning process that considers and balances the impact of transmission system additions on all stakeholders.

IESO

The IESO serves a large centrally-dispatched area encompassing the province of Ontario. Ontario's wholesale electricity market is one of the most diverse in North America. IESO is responsible for ensuring and maintaining the reliable operation of the Ontario Electricity Market and bulk electrical system. In 2005, in accordance with the Market Rules and in agreement with the Ontario Power Authority, IESO published 10-Year and 18-Month Outlooks. These Outlooks assessed the long-term generation and transmission adequacy of the Ontario electricity system from 10 years in the future to within 30 days ahead of real-time operations. In the Outlooks, the IESO identified substantial reliability aspects related to the government initiative to shutdown all coal-fired generating stations. The Outlooks summarize the new generation projects which are under construction or have signed contracts with the government as well as phased generation retirement schedules. Each outlook provides a summary of key transmission reinforcement requirements and identifies enhancements which would satisfy these reliability requirements. For more information on the Outlooks, visit the IESO web-site link: http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp.

In response to the need identified by the IESO and under a directive from the Government, in October, 2005 the Ontario Power Authority (OPA) announced the commencement of generation procurement initiatives to bring 3000 MW of electricity in Ontario, much of it in the Greater Toronto Area. The IESO has provided technical content supporting the formulation of the specifications published by the OPA for the Request for Proposals. The IESO has increased its capability to conduct connection assessments to ensure that reliability and operational impacts are properly assessed and accommodated as the Ontario power system under-goes major transitional changes. With the shift of responsibilities for development of an Integrated Power System Plan (IPSP) to the OPA, the 10-Year Outlook is being discontinued. The IESO will continue to provide security and adequacy assessments to the public, as necessary.

ISO-NE

ISO New England's 2005 Regional System Plan (RSP05) approved by the Board of Directors authorizes spending for approximately $3.0 billion for 272 necessary transmission projects in New England over the next ten years. About two-thirds of this or $2.0 billion will be spent on six major projects in the region and one of the six projects is estimated to cost $1.3 billion. Transmission projects recently completed total about $217 million.

Since 1999 over 9,700 MW of new generation has been interconnected mostly gas-fired combined cycle. The RSP05 projects the resource needs of the region, which could be generation or demand response. It also identifies the amount and type of resource and specific load areas where resources are needed. New England specifically needs quick start and dual fuel or non gas-fired generation. The region has an over dependency on gas-fired generation of about 40% that has resulted in operating difficulties in the past. Without remedial measures, this fuel diversity issue is expected to grow worse with time.

ISO New England leads New England's regional system planning effort through a non-discriminatory open stakeholder process.

Midwest ISO

The Midwest ISO Board of Directors has approved two Midwest ISO Transmission Expansion Plans since the start ISO operations in 2002. These plans have identified $4.3 billion of transmission projects planned and proposed. These plans include more than 390 transmission projects primarily for reliability purposes. About 5,123 miles of transmission line upgrades are projected through 2009, which is about 4.6 % of the approximately 112,000 miles of line existing throughout the Midwest ISO area. Through the end of 2004, over $400 million of these plans have been completed. In the two years of operation completed at the end of 2004, the independent non-discriminatory open access procedures of the Midwest ISO have interconnected 6,400 MW of new generation involving $81 million of new network upgrades.

NYISO

Since the NYISO began operations on December 1, 1999 over 10,000 MW of new generation has been reviewed and approved for interconnection. In excess of 4,500 MW has been constructed and is in service or under construction. This represents a 13% increase in generating capacity for the New York Control Area (NYCA). In addition, the NYISO demand response program has grown to approximately 1,500 MW. Also, the NYISO interconnection process has reviewed and approved two merchant transmission projects – the Cross Sound Cable and the Neptune Project. On December 28, 2004, the FERC approved the NYISO Comprehensive Reliability Planning Process. The NYISO interconnection process now has reviewed or has under review several major transmission projects which will come on line between now and 2007 representing approximately 1.5 billion dollars in investment to maintain system reliability. Finally, as a result of New York's renewable portfolio standard, the NYISO interconnection queue has over 5,000 MW of wind generation under review.

PJM

Since the first Regional Transmission Expansion Plan approval in 2000, up through December 7, 2005, the PJM Board of Managers has authorized over $1.8 Billion of transmission upgrades, $524 Million of which has already been completed. The plan includes $1.3 Billion for baseline reliability transmission system upgrades to serve growing load. A total of $500 million of planned upgrades has accommodated the interconnection of over 17,000 MW of now in-service generating resources representing over 130 projects and will accommodate another 3,800 MW of generation presently under construction. These generation additions enhance system reliability, maintain supply adequacy and support competitive markets for PJM's market participants and the customers they serve. Importantly, the generation additions represent various fuel types, including natural gas, wind and coal. Since its inception in 1997, PJM's open, non-discriminatory planning process has evaluated over 160,000 MW of new generating resource interconnection requests as tracked through PJM's interconnection queues.

SPP

The SPP Board of Directors approved the reliability projects identified in the SPP RTO Expansion Plan (SREP) in April 2005. This SREP included 89 new or accelerated projects totaling $172M of additional investment over the 2005 – 2010 planning horizon which would be Base Plan Funded. SPP updates the SREP every 4 months, consistent with the aggregate study process, to incorporate updates on existing or new projects. The Transmission Working Group approved a final SREP in September 2005 which included an updated reliability plan, as well as presentation of the results from an initial economic transmission expansion planning study. This economic transmission expansion assessment identified 4 potential 345kV projects with reasonable paybacks based on projected production cost savings. SPP has integrated the planning and tariff study processes with the advent of the FERC-approved aggregate study process for Transmission Service Requests. SPP has just completed the facilities study associated with Aggregate Study 2, which includes 34 requests for 2,312MW of new service. Staff has identified 32 projects with installed costs of $212M, which would be assigned to these customers to provide the requested service. In addition to these assigned and allocated expansion projects, this study identified 21 projects, which will be required to maintain reliability. Since 1998 when tariff administration began, SPP has completed 156 generation interconnection studies for 46,317MW of capacity which is primarily wind farm developments. SPP has FERC-approved cost allocation methodologies to address reliability, requested and economic upgrades which should facilitate the implementation of transmission expansion projects.

SUMMARY ISO/RTO SEAMS/BOUNDARY PLANNING ACTIVITIES

In accordance with recent FERC-defined policies that require ISO/RTOs to develop mechanisms to address interregional coordination, PJM, MISO, NY-ISO, and ISO-NE have initiated several efforts to coordinate boundary seams as part of their individual respective planning processes. The ISO/RTOs that are not within FERC's jurisdiction have also developed such coordination agreements. These include the following initiatives:

1. Midwest ISO and PJM Joint Operating Agreement (JOA), December 31, 2003
2. Northeastern ISO/RTO Planning Coordination Protocol, December 8, 2004
3. Midwest ISO, PJM Interconnection, and TVA Joint Reliability Coordination Agreement, April 22, 2005
4. Memorandum of Understanding (MOU) Among NYISO, PJM, and ISO-NE to Coordinate on Natural Gas Supply Conditions Related to Generation, June 3, 2005
5. NYISO and ISO-NE Interregional Coordination and Seams Issue Resolution Agreement (ICA), December 10, 2004
6. Northeastern Independent Market Operators Coordinating Committee (NIMOCC), June 11, 2002
7. CFE/ERCOT Interconnection Study, December 19, 2003
8. Midwest ISO and SPP JOA, December 2, 2004
9. IESO Operating and Interconnection Agreement
10. CAISO Boundary Planning Activities

In addition, a number of other agreements exist between ISO/RTOs and their non-ISO/RTO neighbors that facilitate the coordination of planning activities and the resolution of operational issues. The expansion of interregional markets and intersystem interoperability drive the need for coordinated and integrated system assessments and interregional planning. Inaction could allow unresolved reliability issues to emerge at RTO/ISO transmission interfaces. Without such interregional mechanisms as those listed above to jointly and proactively address seams issues, opportunities to resolve issues related to reliability criteria compliance could be missed.

ISO/RTO Report III discusses each of these initiatives in more detail in terms of the structure of the operating agreements, the associated protocols, and memorandum of understandings. The discussions also review the current state of activities and upcoming activities, including timelines and deliveries for the above initiatives.

SUMMARY OF ISO/RTO ISSUES

The members of the ISO/RTO Council face many common planning issues, including the following:

- The need for locational capacity
- The prospect of unit retirements, especially in load pockets
- The integration of wind generation
- The desire for greater diversity and the reliable delivery of fuel supply
- Changes in environmental restrictions on air emission and their impact on unit dispatch
- Transmission adequacy requirements and the support for proposed projects
- Methods of planning for economic upgrades
- The development of standards and compliance with reliability requirements

The need for locational capacity is based on smaller load areas within an ISO/RTO that need additional capacity because of insufficient generation capacity to meet the area's load and/or transmission import constraints. These areas may also need local capacity to provide economic operating reserve for the area.

Generation retirements can occur for a number of reasons, including but not limited to general aging of a unit, catastrophic failure that makes repair uneconomic, too little operation to justify maintaining a unit, uneconomic operating costs, high compliance costs to meet new environmental requirements, and units no longer needed for local or system reliability. Units might also be required to ensure the reliability of service to small load pockets within the ISO/RTO, necessitating reliability-must-run (RMR) arrangements and delaying unit retirements. Given these reasons, the ability to forecast when units might retire is limited in an energy market environment.

Integrating a small wind generation project into the electricity grid is generally not a major problem. However, as more projects are interconnected, some of which may be larger (i.e. several hundred MWs), the operation of the system with many wind projects can be an issue given the unpredictability of the wind resource in a given region. A study of large amounts of wind generation in New York found that up to around 10% of the region's capacity could be comprised of wind resources before significant operating issues would arise. This conclusion may or may not be generally applicable to other ISOs.

Fuel diversity can be a reliability issue within and across ISOs, as currently is the case with the prospect of natural shortages throughout the country for winter 2005/2006. Looking at several ISO/RTOs simultaneously shows improved fuel diversity, as presented in by Table X from the Northeast Coordinated System Plan or NCSP05 Report, included below.

The table on the following page shows that, overall, generation resources in the Northeast are reasonably balanced across the four major generation types—gas/oil, coal, nuclear, and hydro. A shortage of a fuel like natural gas could affect interregional reliability. The three ISO/RTOs, ISO-NE, NYISO, and PJM, are working together to coordinate gas supply to the broader region since the NYISO and ISO-NE have over a 60% dependency on gas/oil capacity. Because transmission constraints exist within and between the regions, alternative sources of generation cannot always be readily transmitted to areas that may be experiencing fuel shortages.

Table 1: Capacity by Fuel Type for Northeast Region and Canada

ISO/RTO	Type of Generating Capacity										
	Total	Gas/Oil		Coal		Nuclear		Hydro		Other	
	MW	%	MW	%	MW	%	MW	%	MW	%	MW
New England 2004	30,958	63	19,622	9	2,786	14	4,383	10	3,205	3	962
New York 2004	37,549	60	22,708	10	3,597	14	5,080	15	5,777	1	387
PJM 2004	143,878	35	50,978	42	59,760	19	27,426	4	5,301	-	413
Ontario 4/29/04	30,501	14	4,364	25	7,564	36	10,831	25	7,676	-	66
Hydro Quebec 2004	32,963	5	1,478	-		2	675	93	30,660	-	150
New Brunswick 2004	4,430	45	1996	12	515	14	635	21	944	8	340
Total	280,279	36	101,146	27	74,222	17	48,989	19	53,563	1	2,318

Notes:
New England: Gas/Oil includes 8,081 MW of oil and 4,811 MW of dual fuel; "Hydro" includes 1,643 MW of pumped storage; "Other" includes 962 MW of miscellaneous generation (including wood, refuse, tires, etc.).
Hydro-Quebec: "Other" includes wind generation.
New Brunswick: "Other" includes wood and orimulsion.

New air regulation proposals would tighten the emission limits of fossil fuel generating plants. Major initiatives in the East and Northeast United States include the Clean Air Interstate Rule (CAIR), Clean Air Mercury Role (CAMR), and Regional Greenhouse Gas Initiative (RGGI). These rules would affect the costs of higher-emitting generation units relative to lower and non-emitting ones, such as hydro and nuclear facilities. These cost changes will likely affect the market-based dispatch of units and, correspondingly, the transmission flows, which ultimately can impact system reliability. Some analyses of these impacts may be important interregionally.

The requirements for transmission adequacy and interconnection of generators may cause interregional impacts that need study resolution. The timely licensure and construction of needed transmission facilities is vital to the design of a future system. The method of planning of economic upgrades is an important issue that continues to evolve. The development and compliance with NERC standards is a significant ongoing process necessary to ensure reliability.

CONCLUSION

The ISO/RTOs have been successful in creating nondiscriminatory, open, and transparent electric system planning and expansion planning processes that provide an opportunity for all stakeholders to participate. The ISO/RTO planning processes remain dynamic and are still evolving. While some differences exist among the planning processes used by the ISO/RTOs that stem from legacy systems and developmental history concerning local regulation, stakeholder processes and governance, a common thread runs through all the ISO/RTO planning processes, namely a strong commitment to maintaining the reliability of the electricity grid while supporting the expansion of wholesale electricity markets. As a result, needed infrastructure has been identified and placed in service throughout the ISO/RTO areas. The table on the following pages presents a summary of the ISO/RTO planning process.

Table 2: ISO Planning Process Summary

	CAISO	ISO-NE	PJM	NYISO	ERCOT	Ontario	Alberta	SW Power Pool	Midwest ISO
Legal Authority									
Statutory Authority	State and Federal	Federal	Federal	Federal	State	Provincial	Provincial	Federal	Federal
Regulatory Authority	FERC	FERC	FERC	FERC	PUC of Texas	Provincial	Provincial	FERC	FERC
Planning Process, Reliability Planning, Resource Adequacy									
LOLE	Minimum planning reserve requirement currently set at 115%	Determines installed capacity requirement (1 in 10 years). Locational minimum requirements.	Determines installed capacity requirement (1 in 10 years). The current Installed Reserve Margin is 15%. Corresponding transmission system requirement (1 in 25 years). Reliability Pricing Model is under development to support locational capacity requirements and benefits.	Determines installed capacity requirement (1 in 10 years). Includes load uncertainty. Minimum locational capacity req.	Minimum reserve requirement (currently at 12.5%) is based on a 1 in 10 year LOLE criteria for ERCOT.	Determines installed capacity requirement (1 in 10 years). Includes load uncertainty.	No specific requirements at this point in time. Longer term adequacy requirements to be developed.	Minimum capacity margin requirement of 12% based on a 1 in 10 year LOLE criteria, with a provision to reduce the capacity margin to 9% for systems with 75% hydro supply.	Currently apply state or Regional Reliability Organization installed capacity requirements. LOLE analyses to determine transmission import requirements.
Operable Capacity	Local capacity requirements expected to be partially implemented in 2006 and fully in 2007	ISO-developed forecast (50/50 region and 90/10 region and subregion)	RTO-developed forecast (50/50 region and 90/10 region and Transmission Owner Zone)	ISO-developed forecast (50/50)	ISO-developed forecast and region assessment based on minimum reserve and 50/50 peak demand	ISO-developed forecast and region assessment based on participant submitted data, validated by IESO	ISO-developed forecast based on ISO load forecast and WECC Operating Reserve Criteria.	RTO developed forecast and regional assessment based on minimum capacity margin and 50/50 peak demand forecast	Seasonally assessed based on reported resources to meet capacity requirements.
Other		Fuel diversity and air emissions issues evaluated		Fuel diversity and air emissions issues evaluated		Fuel diversity issues evaluated	None.		

	CAISO	ISO-NE	PJM	NYISO	ERCOT	Ontario	Alberta	SW Power Pool	Midwest ISO
Transmission Adequacy									
Reliability Planning	NERC, WECC Planning Standards and more stringent CAISO specific standards	NERC, NPCC and RTO Criteria and Procedures	NERC, MAAC, ECAR, MAIN, SERC and RTO Criteria and Procedures. Reliability First will replace MAAC, ECAR, MAIN on January 1, 2006.	10 yr. Comprehensive Reliability Planning Process which comply with NERC, NPCC and NYSRC Criteria and Procedures	NERC Criteria and more stringent ERCOT Protocols	NERC, NPCC Planning Standards and additional Ontario's localized criteria	NERC, WECC and RTO Criteria and Procedures	NERC, SPP and TO Criteria and guidelines	NERC, MRO, ECAR, MAIN, SERC and TO Criteria and Procedures. Reliability First will replace MAAC, ECAR, MAIN on January 1, 2006.
Economic Planning	Transmission Economic Assessment Methodology established through stakeholder and regulatory process	Information provided to market participants. An open stakeholder process advises on the need for market efficiency upgrades.	Analyzes all congestion to identify opportunities for economic transmission solutions to relieve unhedgeable congestion costs.	Provide Information to the Market on the impact of congestion to facilitate the development of economic upgrades	ERCOT leads annual reviews of economic transmission upgrades to reduce expected congestion costs	IESO publishes extensive market and system information to market participants for this process, including reports by the Market Surveillance Panel on congestion	Economic Planning not distinct and separate; considerations are included as part of the overall planning process.	Economic planning is a key part of the SPP RTO Expansion Plan. Cost recovery associated with Economic Upgrades is a key provision of the SPP Tariff.	Analyze projected congestion to identify opportunities for economic transmission solutions to provide market efficiencies.
Benefit Measure	Societal and Participant benefits	ISO production cost and loss savings criteria	Present value of congestion savings over 10 years is greater than the cost of the transmission solution that mitigates the congestion.	Societal based on bid production cost savings. Also, provide information for congestion elements of LMP both hedged and un-hedged and by major constraint	ISO production cost savings criteria	No fixed measure	See Abive	Economic studies to date have focused on SPP & tier one entities production cost savings over a ten year planning horizon.	Various under review, including aggregate production cost, load marginal energy costs, generator revenues.
Inclusion in Plan		Mandatory	Mandatory for reliability upgrades. Economic upgrades included in plan if there is no proposal for resolution by market participant within one year.	Mandated Regulated Backstop Solutions if not sufficient Market Solutions to resolve reliability violations. Economic upgrades market driven	Mandatory		Yes	Economic studies to date have focused on SPP & tier one entities production cost savings over a ten year planning horizon.	Mandatory for reliability, optional for economic. Optional nature of economic projects currently under review by stakeholders.

	CAISO	ISO-NE	PJM	NYISO	ERCOT	Ontario	Alberta	SW Power Pool	Midwest ISO
Generation Facility Interconnection									
Interconnection Options	Independent variation of Large Generator Interconnection Procedure	Minimum Interconnection Standard (MIS)	PJM generation interconnection requirements as a Capacity Resource or an Energy Only Resource.	Independent variation of Large Generator Interconnection Procedure	ERCOT Generation Interconnection Procedure	Market rules defined connection requirements and assessment process. Also OEB Transmission System Code and Distribution System Code	RTO Technical Interconnection Requirements	Energy Resource per Large Generator Interconnection Procedure	Independent variation of Large Generator Interconnection Procedure
Generator Deliverability Test	Generation must be deliverable to aggregate of load to be counted for resource adequacy planning purposes	Part of the MIS	Part of the interconnection requirements.	Deliverability concept currently under review	Not applicable	Not applicable	Trigger participants and volumes identified.	Not applicable	Part of the interconnection requirements. Generation must be deliverable to aggregate of load to be counted for resource adequacy planning purposes
Funding for Required Upgrade	Generator funding	Generator funding	Funding by the Generator Developer	Class Year cost allocation process for SUFs . Direct attachment paid by generator	All network costs uplifted to loads	Cost allocation processes	Generator funding.	Per LGIP	Currently full credits per pro forma LGIA. Pending Order on proposal for 50% assignment to generator and 50% assignment to load zones on a shared basis.
Point-to-Point Transmission Service	Through and out	Through and out	Through and out	Firm and non-firm service for the transmission of energy from Point(s) of Receipt to Point(s) of Delivery	Not applicable	Not applicable	Not offered.	Per the Aggregate Transmission Service Study Procedures	Offered as per pro forma OATT.
Stakeholder Involvement (approval of need)	ISO, PTO, CPUC, CEC integrated process with stakeholder participation	Open stakeholder process; ISO approval	Open stakeholder process; RTO approval	Open stakeholder process, Shared Governance	Open stakeholder process; ISO approval	Open stakeholder process	Open stakeholder process; ISO approval	Open stakeholder process; RTO approval	Open stakeholder process; RTO approval

	CAISO	ISO-NE	PJM	NYISO	ERCOT	Ontario	Alberta	SW Power Pool	Midwest ISO
Allocation of Responsibilities	NERC Planning Authority	NERC Planning Authority	NERC Planning Authority	NERC Planning Authority	NERC Planning Authority	NERC Planning Authority. Some responsibilities delegated to OPA	NERC Planning Authority	NERC Planning Authority	NERC Planning Authority
Transmission Cost Allocation	Pro-rata allocation of high voltage transmission revenue requirement based on load share.	ISO determination of amount in regional network service rate	RTO determination based on load contribution to criteria violation	Under development and includes more than transmission	Pro-rata allocation based on ratio of coincident peak demand for four summer months.	Cost of any proposed transmission investments is allocated across all ratepayers unless proponent is sole beneficiary	ISO proposed tariff; approval by provincial regulatory authority.	Base-Plan Upgrades are allocated 33% to footprint based on load ratio share, remainder to benefiting entities based on MW-Mi impacts.	Currently License Plate (assigned to constructing zone). Pending Order on proposal for RTO determination based on blend of Postage Stamp and Sub-regional Line Outage Distribution Factors.
Relation to Reliability Council	Member of WECC	Member of NPCC	Member of MAAC, ECAR, MAIN and SERC. Reliability First will replace MAAC, ECAR, MAIN on January 1, 2006.	Member of NPCC and overseen by the New York State Reliability Council		Member of NPCC	Member of WECC	SPP is the RTO and Reliability Council.	Member of MRO, ECAR, MAIN. Reliability First will replace MAAC, ECAR, MAIN on January 1, 2006.
Definition of Transmission	60 kV and above. Excludes subtransmission not operated in parallel with 230 kV and above	69kV and above unless radial	69kV and above unless radial. Less than 69 kV when specified by the Transmission Owner	The ISO Planning Process evaluates facilities defined as "Bulk Power" which is generally 230 kV and above. TO's evaluate non-bulk power facilities	69kV and above	50 kV and above	All facilities above 25 kV.	All facilities 60kV and above after Oct 2005	Facilities transferred to RTO for operational control – generally 100kV and above unless specified otherwise.

ISO/RTO REPORTS

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ISO/RTO REPORT I: PLANNING PROCESSES

AESO

The Alberta Electric System Operator ("AESO") is a provincially-mandated, non-profit statutory corporation that leads the safe, reliable and economic operation and planning of the interconnected transmission system in Alberta. The AESO also facilitates Alberta's hourly wholesale electricity market.

a. Legal Authority

i. Statutory Authority

The Independent System Operator ("ISO") in Alberta, known as the Alberta Electric System Operator, is established in the Electric Utilities Act, Statutes of Alberta, 2003, Chapter E-5.1 ("the Act"). The Act sets out the duties, responsibilities, and obligations of the AESO, including the obligation to act in the public interest. As stated in s. 16 of the Act, the AESO '. . . must exercise its powers and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity." The duties of the AESO with respect to planning the transmission system are set out in s. 17 of the Act and are:

"(i) to assess the current and future needs of market participants and plan the capability of the transmission system to meet those needs;

(j) to make arrangements for the expansion of and enhancement to the transmission system;

(k) to collect, store and disseminate information relating to the current and future electricity needs of Alberta and the capacity of the interconnected electric system to meet those needs, and make that information available to the public;"

The AESO is further subject to the Transmission Regulation, Alberta Regulation 174/2004 (the "Regulation").

Electric industry policy in Alberta is set by the provincial Department of Energy. The AESO is one of four "implementing agencies", the others being the Alberta Energy and Utilities Board ("EUB"), the Market Surveillance Administrator ("MSA") and the Balancing Pool of Alberta. The AESO is governed by its Board of Directors, whose members are appointed by the Alberta Minister of Energy and is independent of any person or entity having a material interest in the Alberta electric industry.

ii. Regulatory Authority

The EUB provides regulatory oversight for the AESO's planning responsibilities and approves the AESO's transmission tariff. The interconnected transmission system in Alberta is owned and operated by six Transmission Facility Owners ("TFO")[1]. Each TFO is compensated by the AESO for use of its facilities through a regulated revenue requirement that is approved by either the EUB, or, in the case of Red Deer and Lethbridge, the Department of Energy.

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[1] They are AltaLink Management Ltd., ATCO Electric, ENMAX, EPCOR, City of Red Deer Electric System and City of Lethbridge Electric System.

b. Summary of Planning Process

The transmission planning process in Alberta is led by the AESO. It prepares a load forecast, generally on an annual basis, and conducts the technical studies necessary to identify required system expansions. Based on the results of these studies a 20-Year Outlook (issued every four years) and a 10-Year Transmission System Plan (issued every two years) is published. These documents provide the contextual background for specific project need applications that the AESO files with the EUB for approval. While the plans and need applications are developed with the input of all stakeholders, including the EUB, through a process that is intended to minimize subsequent regulatory effort each need application is subject to due process. Following EUB approval of the need for a specific project the AESO then direct-assigns the responsibility for implementation of the project to the appropriate TFO. The TFO files a facility application for approval by the EUB for the specific substation and transmission line project components, including siting of transmission line right-of-way.

i. Reliability Planning

The AESO plans the system based on application of its Transmission Reliability Criteria ("Criteria"). The Criteria must, as set out in the Regulation, satisfy the reliability standards of the Western Electric Coordinating Council ("WECC") and the North American Reliability Council ("NERC") unless the AESO determines that to do so would not provide for a safe, reliable or efficient transmission system.

ii. Economic Planning

The AESO is directed by policy and regulation to take a proactive approach to transmission system development to ensure that generation and load customers have fair and open access to constraint-free transmission capacity in order to facilitate an openly competitive and efficient market while maintaining system reliability. The Regulation stipulates that the AESO must plan a transmission system that

- is sufficiently robust to allow for transmission of 100% of anticipated in-merit electric energy when all transmission facilities are in service, and
- is adequate to allow for transmission, on an annual basis, of at least 95% of all anticipated in-merit electric energy when operating under abnormal operating conditions.

iii. Generator/Facility Interconnection Inclusive of Deliverability

Generator/Facility interconnections to the Alberta transmission system are specified in the AESO's Technical Requirements for Connecting to the Alberta Interconnected Electric System (IES). Generation and load customers seeking access to the Alberta system are required to file an application for access service with the AESO however; the AESO does not currently have a formal queuing process. The AESO conducts the studies necessary to determine the impacts of interconnection of the new generation or load and to determine the system expansion or enhancement necessary to mitigate any negative impacts. The requirements for deliverability of generation on the Alberta system are basically described in ii. Economic Planning.

iv. Point-to-Point Transmission Service Request

Currently point-to-point transmission service is not offered in Alberta.

v. Stakeholder Involvement

The AESO engages stakeholder involvement in the planning process through a number of different forums. These forums include one-on-one meetings with individual stakeholders, small group meetings and larger group meetings as circumstances warrant. The AESO has also established a Transmission Advisory Committee ("TAC"), comprised of representatives from a number of key stakeholder groups, to provide advice to the AESO on issues relating to the planning and operation of the transmission system. The AESO is currently developing, with stakeholder input, a set of Stakeholder Consultation Standards that will be used to ensure that uniform stakeholder practices are followed in all aspects of the AESO's operation.

c. Allocation of Responsibility – ISO/RTO vs. TO

The allocation of responsibility between the AESO and the TFOs is set out in the Act. Essentially the AESO is responsible for the planning and operation of the system in a safe, reliable and economic manner. The responsibilities of the TFOs include operation and maintenance of their respective facilities in a manner that is consistent with the safe, reliable and economic operation of the interconnected transmission system. The TFOs are also required to provide, in a timely manner, certain information and assistance as required by the AESO.

d. Cost Allocation

Transmission system costs are allocated according to the AESO transmission tariff that is approved by the EUB. Generation customers are responsible to pay for all local interconnection costs associated with their specific project. The AESO will "invest" in load customer facilities based on the Customer Contribution Policy that forms part of its tariff. Beginning January 1, 2006 all transmission system costs, excluding the cost of transmission losses, will be allocated to load customers on a postage-stamp basis. Transmission losses will be allocated to generation customers on a locational basis. Generation customers will also be required to pay a "system contribution" fee, based on size and location, refundable over a 10 year period if certain operating characteristics are achieved.

e. Relation to Reliability Councils

The AESO is a voluntary participating member of the WECC and is a signatory to its Reliability Management System ("RMS") agreement. The AESO is also a member of NERC and the Northwest Power Pool ("NWPP") and participates in the activities of these and other organizations to ensure its planning is coordinated within the larger regional setting.

f. Definition of Transmission

The AESO has the planning and operations responsibility for the transmission system in its entirety. A "transmission facility" in Alberta is defined in the Act as "an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer operating phase to phase at a nominal high voltage level of more than 25 000 volts to a nominal low voltage level of 25 000 volts or less." This essentially includes all lines and substation equipment energized at 25 kV and above.

CAL-ISO

The California Independent System Operator Corporation (CAISO) is a state chartered (state mandated), nonprofit corporation that controls the transmission facilities of all Participating Transmission Owners[2] (PTOs) serving approximately 75% of the load in the state. The remaining load is mainly served through the independently operated and planned systems of Sacramento Municipal Utility District (SMUD), Los Angeles Department of Water & Power (LADWP) and the Imperial Irrigation District (IID).

a. Legal Authority

i. Statutory Authority

CAISO has a statutory obligation to maintain transmission system reliability under California State laws. The CAISO works with the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and Utility Distribution Companies (UDC) to maintain a reliable and operable transmission system in California. The CAISO provides the CPUC and CEC with input on transmission policy, transmission system requirements, and expansion projects. The CPUC coordinates the siting process and selection of future resources with the CAISO in order to promote electric system reliability and utility financial integrity. The CEC is the primary energy policy and planning agency with responsibilities that include forecasting future energy needs and licensing of thermal power plants. The CEC provides load forecasts and information on new generation projects and retirements of existing generation to the CAISO.

The CAISO is also subject to the FERC statutory requirement under §§ 205 and 206 of the FPA that a utility's rates must be "just and reasonable." FERC looks to the CAISO for determinations as to whether new transmission by a PTO is necessary and cost effective.

ii. Regulatory Authority

The CAISO is subject to FERC's regulatory authority and FERC provides CAISO with its grid planning authority. The CAISO originally consisted of three investor-owned utilities (PG&E, Edison, and San Diego Gas & Electric Company), each of which is subject to FERC's jurisdiction. Each of the utilities is compensated by the CAISO for the use of its facilities through a transmission revenue requirement ("TRR"), which consists of the costs and rate of return to which the utilities are entitled as participating transmission owners. FERC independently examines each of these jurisdictional utilities to ensure that their revenue requirements are just and reasonable.

b. Summary of Planning Process

In general, the expansion planning process is led by CAISO in order to establish the reliability and economic need. The expansion plans are developed through a collaborative process that includes PTOs, State, and other stakeholders. The PTOs perform the majority of the technical analyses for their respective systems and jointly participate in development of longer-term assessments. The CAISO reviews and approves PTO plans and assessments based on applicable planning standards and criteria, and technical and economic feasibility.

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[2] The three major PTOs include Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E).

A new economic test - Transmission Economic Assessment Methodology (TEAM) has been developed to provide a common methodology to evaluate the economic need of transmission upgrades based on local and regional benefits, market power, and uncertainty of a wide range of future system conditions, operational feasibility, and the comparison of valid alternatives. An Alternative Dispute Resolution (ADR) Procedure is available to address any questions on reliability or the economic need of a project.

i. Reliability Planning

The ISO Grid coordinated planning process involves review of proposed system upgrades and expansion to ensure efficient use of the system and enhance operating flexibility. The Comprehensive ISO Grid Expansion Plan is developed from:

a. Proposed generation projects identified through interconnection requests,
b. The ISO Controlled Grid Plan that includes needs identified by PTO's through the PTO's Annual Transmission Plans. The PTO's Annual Transmission Plan describing proposed facility additions covers a 10 year planning horizon,
c. Needs identified by the ISO or Market Participant or through special focused plans, and
d. Reliability Must Run (RMR) Generation, Local Area Reliability Service (LARS), Resource Adequacy Requirements (RAR) studies

CAISO has authority to mandate system upgrades required for reliability deficiencies. The CPUC also has authority to require an upgrade or expansion of PTO facilities to meet regulatory obligations.

ii. Economic Planning

As part of the coordinated planning process, the PTO and Market Participants assist the CAISO in evaluating needed expansions that promote economic efficiency. Expansion plans under this category may be funded fully by a project sponsor or through rate-based recovery. The need for an expansion under a fully funded option may be established solely by demonstration of commitment and financial capability to complete the project. In return, the project sponsor would receive Financial Transmission Rights (FTR) associated with the expansion. Expansions funded through the rate base require an economic determination to assess whether the benefits support the cost of the proposed plan and is the least cost alternative to promote economic efficiency.

iii. Generator/Facility Interconnection Inclusive of Deliverability

Currently, new Generator/ Facility interconnection as described under Amendment No. 39 to the CAISO Tariff (April 2, 2001 accepted June 1, 2002) establishes the process in California until FERC approves CAISO Compliance filing on Order 2003B. Amendment 39 promoted consistency of the individual PTO tariff's in regards to the Generator Interconnection process and resulted in PTO's modifying their tariff's to conform to Amendment 39. The current interconnection process includes an initial application to the CAISO to enter into a project queue and successful completion of a System Impact Study and Facility Study prior to execution of an Interconnection Agreement.

Deliverability is an essential element of the CPUC's resource adequacy requirements included in the CAISO planning process. The CAISO's deliverability proposal (currently under development) consists of three assessments that include the deliverability of

Generation to the aggregate of load, the deliverability of Imports and the deliverability to Load within transmission constrained areas (locational capacity requirement)

iv. Point-to-Point Transmission Service Request

Currently point-to-point transmission service is not offered in California.

v. Stakeholder Involvement

Stakeholders are involved in a coordinated planning process and review to ensure needs identified by various market participants can be addressed through system upgrades, system expansion, including interconnection of new generation and through demand side programs, where appropriate. The State and other stakeholders participate in all processes to provide guidance and recommendations on process objective and to assure continuity of information across all forums.

c. Allocation of Responsibility - ISO/RTO vs. TO

CAISO is responsible for the reliable operation and security of facilities under its control. The member PTOs have the statutory and regulatory obligations to plan and maintain a reliable system to serve their customers. Together the CAISO works closely with FERC, the CPUC, the CEC and other stakeholders when planning the ISO-Controlled Grid. The PTOs develop system expansion plans to meet their area needs and also perform system impact assessments of potential interconnections to their systems. The CAISO reviews and approves the technical and operation feasibility of all ISO Controlled Grid plans based on the applicable NERC/WECC and CAISO planning standards and criteria.

d. Cost Allocation

All Market Participants withdrawing energy from the CAISO Controlled Grid pay the transmission access charge which is designed to recover the Participating Transmission Owners transmission revenue requirement. There is a high voltage access charge and a low voltage access charge. After a ten-year transition period, the amount of the high voltage paid to the CAISO is in proportion to the Market participants load. The low voltage access charge is paid to the utility distribution companies.

Interconnection customers are responsible for all costs of direct interconnection of their facilities to the power system. The developer initially funds network system upgrades or expansion required to interconnect a developer's project. Following commencement of commercial operation, the project is entitled to a repayment of the cost of network upgrades on a dollar-for-dollar basis within a five-year timeframe.

e. Relation to Reliability Councils

The CAISO and the PTOs in California are voluntary participating members in the Western Electricity Coordinating Council (WECC) and NERC. The CAISO comprehensive grid planning process coordinates with the entire western interconnection through WECC and Seams Steering Group – Western Interconnection (SSG-WI) to ensure reliability of interconnected system operation and coordination of planning.

f. Definition of Transmission

ISO Controlled Grid is the system of transmission lines and associated facilities of the PTOs that have been placed under the ISO's Operational Control. These include 66 kV and above facilities that create parallel path flow on bulk power transmission facilities (230 & 500 kV) and entitlements, but excludes directly assignable radial lines and associated facilities interconnecting generation, lines and associated facilities classified as "local distribution" facilities or other facilities excluded consistent with FERC established criteria for determining facilities subject to ISO Operational Control. The ISO may refuse to accept control over any transmission lines, facilities or entitlements that are located in a Control Area outside of California, are operated under the direction of another Control Area or independent system operator, and cannot be integrated into the ISO Controlled Grid due to technical considerations.

ERCOT

The Electric Reliability Council of Texas (ERCOT) is state chartered (state mandated), non-profit corporation that controls and operates the transmission facilities in the State of Texas.

Transmission planning (60-kV and above) in the current environment is a complex undertaking that requires significant work by, and coordination among, ERCOT and the Transmission/Distribution Service Providers (TDSPs), as well as with other market participants. ERCOT works directly with the TDSPs, stakeholders/market participants through the Regional Planning Groups. Each of these entities has responsibilities to ensure the appropriate planning and construction occurs.

a. Legal Authority

i. Statutory Authority

Under the Public Utility Regulatory Act (PURA), the Independent Organization (IO) is charged with nondiscriminatory coordination of market transactions, system-wide transmission planning, network reliability and ensuring the reliability and adequacy of the regional electric network

ii. Regulatory Authority

The IO ensures access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms. ERCOT has been certified by the PUCT as the Independent Organization for the ERCOT region of NERC.

b. Summary of Planning Process

Posting of Documents and Communication

ERCOT Staff will maintain a controlled access area on the ERCOT Internet website listing all projects and system planning related data unless it is considered protected or proprietary information. Access to such information is controlled because this information is considered protected Critical Energy Infrastructure Information by FERC and the Department of Homeland Security. This site will be the official channel for providing information to the stakeholders/market participants. In addition, ERCOT staff will notify stakeholders via email of important items posted and this will constitute official notice of the posting.

Planning Process

The planning process begins with computer modeling studies of the generation and transmission facilities and substation loads under normal conditions in the ERCOT system. Contingency conditions along with changes in load and generation that might be expected to occur in operation of the transmission grid are also modeled. To maintain adequate service and minimize interruptions during facility outages, model simulations are used to identify adverse results based upon the planning criteria and to examine the effectiveness of various problem-solving alternatives.

The effectiveness of each grid configuration and facility change must be evaluated under a variety of possible operating environments because loads and operating conditions cannot be predicted with certainty. As a result, repeated simulations under different conditions are often required. In addition, options considered for future installation may affect other alternatives so that several different combinations must be evaluated, thereby multiplying the number of simulations required.

Once feasible alternatives have been identified, the process is continued with a comparison of those alternatives. To determine the most favorable, the short-range and long-range benefits of each must be considered including operating flexibility and compatibility with future plans.

Major Project Input from Stakeholders

Major projects (345-kV and above) require a significant amount of time to develop, study, review, and possibly approve. These large projects should be reviewed, at several times by the RPG during the course of the transmission planning process described in this document. They will be presented to the group at the initial study scope stage, in the middle of the study, and when the study is completed. This should prevent iterative/repetitive wasteful study work from being performed.

Supervise Processing of Requests for New Generation Interconnection or Generation Additions

As required under PUCT Substantive Rules, ERCOT will receive all new generation interconnection requests and additions in accordance with the procedure entitled "GENERATION INTERCONNECTION REQUEST PROCEDURES." As a part of that process ERCOT will perform a steady-state security screening study to determine site feasibility for interconnection and at what level the generator can expect to operate with other generation in the area in operation before significant transmission additions are necessary. ERCOT will also make a very rough estimate of the transmission system additions needed to integrate the new generation. This information in the form of a report will be presented to the generating entity requesting interconnection, and the generating entity can then decide if it wants to continue to request interconnection at that site or withdraw the application. At that time, ERCOT will inform the generating entity if it considers the proposed site to be inappropriate to the point that ERCOT will not support the addition of transmission needed to integrate the project into the transmission system. If the generating entity decides to go forward at the designated site, ERCOT will then initiate a full interconnection study with the transmission owners of the respective RPG with the lead TDSP designated as the one directly affected by the interconnection. Generation interconnection requests will remain confidential until an interconnection agreement or financial agreement for transmission construction is completed with a transmission owner. An official letter from a municipal utility or electric cooperative will also serve as a public commitment. At that time, the generation project will be regarded as a confirmed project and will be posted on the ERCOT Internet website along with copies of generation interconnection impact studies and related proposed transmission projects. Generation interconnection projects will not be reviewed in the RPG process unless the interconnection transmission lines are in excess of five miles in length. These transmission projects will then enter the open process for final RPG concurrence of the projects associated with the generation plant dependent upon the firm commitments of the generation owner.

Types of Network Solutions

A transmission project designated as "without generation re-dispatch options" indicates that the binding constraint(s) driving the need for the project does not have any generators whose dispatch can be altered to eliminate an ERCOT Planning Criteria reliability violation. Economic evaluation is necessary only of alternate transmission project upgrade options. It is imperative that these reliability-justified projects continue to be identified and built in a timely manner.

For any grid-related system security issue where the mix of existing generators in the market can have their commitment and dispatch altered to eliminate security violations, the grid limitation is generation related. If a non-transmission upgrade alternative is available, a comparative economic evaluation is warranted to determine the most economically efficient energy delivery option, and therefore, can be identified as “with generation re-dispatch options.” Non-transmission alternatives include, but are not limited to, load interruption (DSM), Out of Merit Capacity (OOMC), Out of Merit Energy (OOME), Local Balancing Energy (LBE), and Reliability Must-Run (RMR) services. These components contribute to local congestion costs currently “uplifted” or socialized, in a similar manner to wires charges, and therefore fall into the desired optimization mix necessary to minimize energy delivery costs. Demand (load) response may also be considered an option, if it can be feasibly evaluated as a reliable option.

ERCOT System Operations utilizes an Energy Management System (EMS), which can issue RMR, OOMC, and OOME instructions as necessary to ensure that the proper mix of generation will be online and dispatched to the proper output levels to ensure secure and reliable real-time operation. When evaluating the transmission system, a security-constrained unit commitment and economic dispatch algorithm will be used, if available, to determine if a secure commitment and dispatch combination exists for potential binding transmission constraints. While traditional power flow tools can determine what transmission upgrades are necessary to render re-dispatch of generation unnecessary, the economic implications associated with the cost of energy is not captured. ERCOT will endeavor to develop reasonable comparisons of options.

Project Scope

Studies for transmission projects (60-kV and above) proposed by ERCOT staff, TDSPs, and other market participants should maintain a consistent structure that contains the following elements:

- A description of the reliability and/or economic problem that is being solved;
- Analysis of rejected alternatives, including cost estimates, effect upon transfer capability, and other factors considered in the comparison of alternatives with the proposed project;
- Assumptions modeled in performance studies such that credible performance deficiencies can be identified through study;
- Performance analyses that are consistent with system operating practices and procedures and are compliant with the ERCOT Planning Criteria;
- A documented process to identify specific performance deficiencies (reliability and economic);
- Stakeholder/market participant review of the assumptions justifying transmission projects based on economic benefits as opposed to reliability criteria violations;
- Both transmission and non-transmission solutions to performance deficiencies should be considered where possible. Estimates of costs should account for transmission investments, system losses, and congestion relief. To the extent generation dispatch can alleviate reliability needs, both reliability and economic impacts should be considered in the selection of solutions;

- Consideration of alternatives submitted by market participants and due consideration of their transmission project proposals, and with the provision of an opportunity for timely input by other stakeholders;
- Implementation of planned solutions on a schedule that permits adjustment of scope or schedule when study conditions change significantly;

Submitted Transmission Proposals for ERCOT Review

A two-tiered evaluation and approval process will be used to separately address small (local) and major (bulk) transmission planning projects. ERCOT Staff and RPG participants may request additional information if necessary to complete their evaluation.

The first tier is for 'small' projects that will consist of those proposals that are 138-kV and below not requiring a CCN, all autotransformer additions or upgrades, transmission switching station construction, and transmission reactive support additions. These first tier projects will be submitted for review to the respective ERCOT Regional Planning Group only. Once the review process is complete and the project is approved, the group, through ERCOT, will issue a letter of acceptance. ERCOT will have coordinating authority over the planning activity through their membership on each RPG. This review of the 'small' transmission projects is needed to ensure a coordinated effort between TDSPs, as well as, to allow the REPs to understand the amount of proposed transmission costs over the planning horizon so that it can be factored into retail pricing.

The second tier is for 'major' transmission projects at 345-kV and above or any other project proposal that will require a CCN. These would be submitted for review to the respective ERCOT RPG as well, but would also be evaluated independently by ERCOT staff. Once ERCOT has completed their assessment, an approval letter would then be issued for the project if so warranted.

Entities that are exempt (like municipals) from getting a CCN for transmission projects will be handled as if they were "not exempt" for this review process. Further clarification: If the project was being constructed by a municipal and the project did not require a CCN (like a regulated entity), it would be handled as a first tier review project. If the project was being constructed by a municipal and the project would require a CCN (like a regulated entity), it would be handled as a second tier review project.

Projects that will be exempted from the RPG review process are:

- Construction necessary to connect and support individual load customers to the system or accommodate load growth of existing individual customers;
- Replacement of failed, obsolete, or aged equipment, except in cases where such equipment is replaced with higher rated equipment for the purpose of increasing transfer capability.
- The ERCOT review process consists of the following steps:
- Transmission projects for review are submitted to the ERCOT Lead Planning Engineer (LPE) for the corresponding planning region
- ERCOT will provide electronic copies of the submittals to members of the corresponding ERCOT Regional Planning Group to solicit comments within seven days of receipt.

- All concerns/questions or objections about a project should be submitted to the corresponding RPG and ERCOT Lead Planning Engineer for the planning region within 21 days after ERCOT's transmittal to members of the corresponding RPG.
- Any questions related to data deficiency should be submitted to ERCOT and the requestor immediately.
- If concerns/questions or objections about a project are received, the project will be put into "study mode" for an additional 28 days to resolve those concerns as determined by the ERCOT Lead Planning Engineer in that region.
- ERCOT will assume acceptance of the project if no concerns/questions or objections are provided within 21 days of ERCOT's transmittal to members of the corresponding RPG.
- ERCOT will consider all productive comments and factor it into their independent review of the project. The comments provided to ERCOT and RPG should be constructive and viable. Comments should be based on good utility practice, and sound engineering judgment and suggestions should be able to be implemented by the transmission provider constructing and operating the project.
- ERCOT's independent analysis will be based upon the ERCOT Planning Criteria and NERC Planning Standards and may include some review for market activities (economic evaluation).
- Regional Planning Group members and PUCT Staff should each provide a "single" complete comment from their company about each project by the end of the 21-day review period rather than sending multiple comments at various times. A single comment will help ERCOT and the transmission provider keep track of the comments and develop an appropriate response.
- For the 'small' tier projects, the RPG will try to complete their review for a project in 45 days or less. If the RPG is unable to complete their review based within 45 days, ERCOT will contact the requestor to provide a reason for the delay and expected completion time.
- For the 'major' tier projects, ERCOT will try to complete their independent analysis and review for a project in 90 days or less. If ERCOT Staff is unable to complete their independent analysis and review based on RPG input within 90 days, ERCOT will provide the requestor a reason for the delay and expected completion time.
- ERCOT will post all recommended transmission projects, including support information for the projects, on its website and notify the corresponding ERCOT Regional Planning Group distribution lists of the posting.
- At the appropriate time intervals ERCOT will schedule open meetings for all interested parties to discuss the transmission projects prior to their final consideration.

Recommended Transmission Projects to ERCOT Board

Following the RPG open meetings and after all remaining questions have been answered, ERCOT will determine which 345-kV and special transmission projects are to be submitted to the ERCOT Technical Advisory Committee (TAC) for information purposes and to the ERCOT Board for review, concurrence and endorsement. Projects recommended by ERCOT Staff that do not receive TAC's concurrence will be presented to the Board for their consideration and final determination. All other transmission projects will be handled and supported by ERCOT Staff with input from the RPGs.

Determine Designated Providers of Transmission Additions

Following ERCOT Board concurrence, ERCOT Staff will determine designated providers for the recommended transmission projects. The default transmission providers will be those transmission providers that own the end points of the new projects. Those transmission providers can agree to provide or delegate the new facilities or inform ERCOT that they do not elect to provide the new facilities. If a default provider elects not to provide a recommended new facility, ERCOT will consider offers from other providers based on the merits of their proposal. If different providers own the two ends of the recommended project, ERCOT will designate them as co-providers of the recommended project, and they can decide between themselves what parts of the recommended project they will each provide. If they cannot agree, ERCOT will determine their responsibility following a meeting with the parties. If a designated provider agrees to provide a project and does not diligently pursue the project within the time frame specified before a CCN is granted, ERCOT will designate an alternate provider based on the merits of the proposals submitted by other providers.

Notify PUCT of Recommended Transmission Projects

ERCOT will formally inform the PUCT of all ERCOT Board-recommended transmission projects and of the designated providers for those projects. ERCOT will then support those projects in future CCN proceedings required for those projects through the use of filed supporting documents and testimony if necessary. ERCOT will also track via TPIT the status of these projects as they are implemented.

Regulatory Authorization

Most new transmission line construction and some line reconstruction require the approval of the PUCT. It is the responsibility of the transmission service provider building the facility to apply for and obtain the Certificate of Convenience and Necessity (CCN) and all other required regulatory approvals. The present PUCT rules allow the PUCT up to 12 months for consideration of the CCN, with some provisions for expedited approval of uncontested applications and critical projects. The need to perform a routing study and for the transmission service provider to hold public meetings typically adds another 12 months to the time required to certify and build a new transmission line. In most new transmission projects, the acquisition of right of way and construction can take up to 12 months after a CCN is granted by the PUCT. As a result, firm commitments should be made at least three years ahead of required in-service dates for most transmission line projects, and some projects may require commitments four to eight years in advance of system needs.

Transmission Line Routing

In the case of new transmission lines, ERCOT performs no specific routing evaluation or proposal at this stage other than generally trying to favor existing rights of way and avoiding known congested or environmentally sensitive areas. Specific routing evaluations and proposals are the responsibility of the particular transmission service provider that develops and constructs each project. ERCOT encourages them to address landowner concerns and attempt to reach a mutually acceptable resolution, recognizing this cannot be done unilaterally. If that cannot be done, the specific routing issues may be raised and addressed at the PUCT in CCN proceedings related to the particular project, if applicable.

c. Allocation of Responsibility – ISO vs. TO

The ERCOT Staff will supervise and exercise comprehensive independent authority of the overall planning of transmission projects of the ERCOT transmission grid (transmission system) as outlined in PURA and Public Utility Commission of Texas (PUCT) Substantive Rules. ERCOT's authority with respect to transmission projects that are local in nature is limited to supervising and coordinating the planning activities of transmission service providers. The PUCT Substantive Rules further indicate that the IO "shall evaluate and make a recommendation to the commission as to the need for any transmission facility over which it has comprehensive transmission planning authority." In performing its evaluation of different transmission projects, ERCOT takes into consideration whether the proposed transmission projects are reliability justified by the ERCOT transmission planning criteria and/or are economically justified by the reduction of congestion and losses. To accomplish this goal, ERCOT will:

- Study and monitor the transmission system for current and future transmission constraints;
- Review generation additions and determine adequacy of generation reserve levels (currently 12.5% or greater);
- Support development and validation efforts for appropriate and accurate modeling of generation, load and transmission equipment needed to support operations/planning studies and simulations.
- Perform simulations in order to determine the impact of various transmission line contingencies, load and generation levels on the reliability of the ERCOT transmission system;
- Review, assess possible impacts and approve remedial action plans (RAP) and special protection systems (SPS);
- Supervise the processing of all requests for interconnection to the transmission system from owners of proposed new or expanded generating facilities, including performing or coordinating any applicable system security studies;
- Lead and supervise the three regional planning groups (North, South, and West) in the consideration and review of proposed projects to address transmission constraints and other system needs;
- Conduct an open process of public review and comment on all proposed transmission facility additions;
- Consider new transmission proposals submitted by all interested parties;
- Recommend needed transmission facility additions that are reliability justified by the ERCOT transmission planning criteria and/or are economically justified by the reduction of congestion and losses, or are required for integrating new generating facilities into the ERCOT system;
- Submit all final recommended 345-kV transmission facility additions and, in some special cases, 138-kV additions to the ERCOT Board of Directors for review and concurrence;
- Determine the providers of transmission additions;
- Notify the PUCT of all Board-supported transmission facility additions and their designated providers;
- Support, to the extent applicable, a finding by the PUCT that a project is necessary for the service, accommodation, convenience, or safety of the public within the meaning of PURA §37.056 and PUCT Substantive Rule §25.101;

- Work with the Steady-State Working Group (SSWG), Dynamic Working Group (DWG) and System Protection Working Group (SPWG) to model equipment, create databases, perform tests with the TDSPs to evaluate compliance of their transmission facilities with the ERCOT Planning Criteria, and recommend further studies if needed.

TDSP Responsibilities

TDSPs shall:

- Ensure review and compliance with PURA and PUCT Substantive Rules obligations to plan, build and operate the transmission system for the benefit of all users;
- Perform appropriate tests to ensure the reliability of its own transmission facilities, recommend studies, and propose appropriate solutions;
- Utilize the RPG process as the forum for ERCOT Staff, PUCT Staff, consumers and stakeholder/market participant review of all proposed transmission projects;
- Provide accurate and appropriate load data via the ALDR process;
- Provide data necessary to allow RPG members to replicate studies of project proposals and feasible alternatives.
- Actively participate in and support the RPG efforts and ROS working groups by providing timely input, study comments and responses to comments submitted;
- Recommend coordinated studies to the RPGs as needed of those conditions of importance to multiple ERCOT TDSPs or the entire ERCOT power system;
- Support analysis and reports needed for the ERCOT Board to make the final decisions on the projects necessary to fulfill PURA and PUCT Substantive Rules obligations;
- Be responsible for obtaining the Certificate of Convenience and Necessity (CCN) and all other required regulatory approvals;
- Make every effort to adhere to the project schedule to meet the needs as determined by ERCOT and the RPGs;
- Provide to ERCOT electronic copies of their planning criteria (or any basis document or philosophy used to justify transmission additions) and notify ERCOT of any changes within 30 days;
- Provide electronic copies of all generation interconnection requirements and notify ERCOT of any changes within 30 days;
- Provide to ERCOT their annual report of all planned transmission projects.

Stakeholder/Market Participant Responsibilities

With the implementation of retail competition in the ERCOT market and the associated changes in market design and operations, more market participants and stakeholders have a financial stake in the development of a reliable and cost-efficient transmission system. The Retail Electric Providers (REPs) and load-serving Qualified Scheduling Entities (QSEs) pay for transmission wires services and for local congestion (i.e., Out of Merit Order Capacity (OOMC), Out of Merit Order Energy (OOME), and RMR services).

Stakeholders/Market Participants shall:

- Actively participate in the ERCOT transmission planning process to encourage efficient, reliable, and cost-effective long-term transmission system development;

- Provide accurate, appropriate and timely data including performance characteristics and limitations upon request by ERCOT and TDSPs for their simulations and analysis;
- Review proposed projects and provide timely comments about projects submitted to the RPGs for their review that address reliability and/or economic deficiencies of the transmission system;
- Provide data necessary to allow RPG members to replicate studies of project proposals. This includes identifying the previously posted PTI PSS/E case to be used as the reference case, supplying PTI PSS/E IDEV file (or PowerWorld Simulator Auxiliary Files) to modify the case as necessary to develop the study case and supply a written description of the project proposal, alternatives considered, and any other case changes that were necessary to replicate the study;
- Develop and submit accurate/appropriate proposed projects for review.

All market participants, regardless if they are a TDSP, may develop and submit proposed projects to the Regional Planning Groups (RPGs), as well as review projects developed and proposed by the RPGs. Broad participation in the process results in a thorough development of projects. However, confidentiality provisions prevent participation of non-TDSPs in the studies leading to interconnection agreements with generators until they become public.

Public Utility Commission (PUCT) Responsibilities

The PUCT works under the authority of PURA as defined by the Substantive Rules.

PUCT shall:

- Participate in the Regional Planning Groups;
- Monitor the TDSPs and the RPGs to assure their activities are non-discriminatory;
- Require, as appropriate, a TDSP to provide transmission service, including the construction or enlargement of a facility;
- Review and approve or reject applications from TDSPs for an amendment to their Certificate of Convenience and Necessity (CCN) for the construction of transmission facilities consistent with the PUCT Substantive Rules;
- Resolve disputes between ERCOT, TDSPs, consumers, and other market participants concerning transmission projects consistent with the PUCT Substantive Rules.

Regional Planning Group Responsibilities

ERCOT leads three regional planning groups (North, South, and West) in the consideration and review of proposed projects to address transmission constraints and other system needs. Participation in these regional planning groups is required of all TDSPs and is open to all market participants/stakeholders, consumers, and PUCT staff personnel. ERCOT staff is responsible for leading and facilitating the RPG processes.

The goals of these regional planning groups are:

- Coordinating transmission planning and construction to ensure that the ERCOT and NERC planning standards are met, that a proposed project addresses ERCOT planning criteria requirements, and that transmission upgrades address needs;
- Improving communication and understanding between neighboring TDSPs on operating procedures, SPSs and RAPs that respond to contingencies, voltage deviations, and facility overloads;

- Preventing inefficient solutions to regional problems through a coordinated effort and resolving the needs of the interconnected transmission systems while ensuring a reliable and adequate network;
- Seeking a cost-effective balance between costs and lead times in the plans produced to ensure and maintain reliable service;
- Planning the bulk transmission system with sufficient lead time to avoid the unnecessary upgrades to the underlying transmission systems taking into account the transfer capacity needs between load and generation pockets to avoid unreasonable congestion costs.

Project endorsement through the ERCOT Regional Planning process is intended to support, to the extent applicable, a finding by the PUCT that a project is necessary for the service, accommodation, convenience, or safety of the public within the meaning of PURA §37.056 and PUCT Substantive Rule § 25.101.

d. Cost Allocation

PUCT Substantive Rule §25.195 requires Transmission Service Providers (TSPs) to plan, construct, operate and maintain their transmission systems in accordance with good utility practice and to place into service sufficient transmission capacity to ensure adequacy and reliability of the network. In addition, each TSP is required to complete transmission improvement projects recommended by ERCOT which are required to provide reliable transmission service and to relieve any transmission constraints identified by ERCOT. For projects requiring a CCN, ERCOT designates the TSP(s) responsible for the construction (or acquisition) of transmission facilities necessary to remedy the identified constraint(s) and permit the transmission service requested.

A new generation provider in ERCOT requesting an interconnection and transmission service is responsible for the cost of installing step-up transformers, breakers, and protective devices at the point of interconnection capable of isolating the generation source from the transmission grid. The TSP is responsible for all other interconnecting facilities and any transmission upgrades necessary on its own system to accommodate the requested transmission service.

To recover these costs, PUCT rules also require all TSPs to file a tariff for transmission service to be applied to all distribution service providers (DSPs) and to any entity scheduling the export of power from the ERCOT region. The TSP's annual transmission rate is calculated at it commission-approved Transmission Cost of Service (TCOS) divided by the average of ERCOT coincident peak demand for the months of June, July, August, and September (4CP). (ERCOT is required to provide to the PUCT the current year's 4CP by DSP on December 1 of each year.) The TSP's annual transmission rate is then converted into a monthly rate. Each DSP taking transmission service pays an amount equal to each TSP's monthly rate, as filed in its tariff, times the DSPs previous year's average of the 4CP demand coincident with the ERCOT 4CP**.**

PUCT rules also allow each TSP to annually revise its transmission service rates to reflect additional capital investments without having to file a new formal TCOS rate case. However, these new rates are subject to reconciliation at the next formal TCOS filing.

e. Relation to Reliability Councils

ERCOT is its own Reliability Council as well as an ISO.

f. Definition of Transmission

The following facilities are deemed to be Transmission Facilities within ERCOT:

- Power lines, substation, and associated Facilities, operated at 60 kV or above, including radial lines operated at or above 60 kV.
- Substation Facilities on the high side of the transformer, in a substation where power is transformed from a voltage higher than 60 kV to a voltage lower than 60 kV or is transformed from a voltage lower than 60 kV to a voltage higher than 60 kV.
- The direct current interconnections with the Southwest Power Pool (SPP), Western System Coordinating Council (WSCC), Comisión Federal de Electricidad, or other interconnections.

IESO

The Independent Electricity System Operator (IESO) controls Ontario's bulk electrical system, balancing the demand for and supply of electricity on a second-to-second basis to meet the electricity needs of over 11 million Ontarians. It also operates the competitive wholesale market, which involves, among other things, collecting offers from suppliers and bids from purchasers to determine the on-the-spot market price for electricity that reflects demand across the province.

Formally, the IESO is a non-profit, regulated corporation without share capital established by the Electricity Act, 1998 (Ontario). It is independent of all other players in the industry and is managed in the interest of all involved.

a. Legal Authority

i. Statutory Authority

- The Electricity Restructuring Act, 2004 (Ontario), the governing legislation for electricity in Ontario, assigns explicit statutory responsibility for medium and long-term planning to the Ontario Power Authority (OPA). The OPA is a non-profit statutory corporation with an independent board of directors that reports to the Legislature of Ontario through the Minister of Energy. The corporation is licensed and regulated by the Ontario Energy Board (OEB). Its costs will be recovered through OEB-approved fees to electricity users.

The objects of the IESO as specified in the legislation include:

- to direct the operation and maintain the reliability of the IESO-controlled grid to promote the purposes of the Act;
- to participate in the development by any standards authority of standards and criteria relating to the reliability of transmission systems;
- to work with the responsible authorities outside Ontario to co-ordinate the IESO's activities with their activities;
- to collect and provide to the OPA and the public information relating to the current and short-term electricity needs of Ontario and the adequacy and reliability of the integrated power system to meet those needs;

The objects of the OPA as specified in the legislation include:

- to forecast electricity demand and the adequacy and reliability of electricity resources for Ontario for the medium and long term;
- to conduct independent planning for electricity generation, demand management, conservation and transmission and develop integrated power system plans for Ontario;
- to engage in activities in support of the goal of ensuring adequate, reliable and secure electricity supply and resources in Ontario;
- to collect and provide to the public and the Ontario Energy Board information relating to medium and long term electricity needs of Ontario and the adequacy and reliability of the integrated power system to meet those needs.

The North American Electric Reliability Council ("NERC") Functional Model requires that an entity within an Area be designated as the "Planning Authority" for that Area. As agreed between the OPA and the IESO, the IESO shall act as the Planning Authority for Ontario and shall be responsible for the execution of all Planning Authority tasks as specified by the Functional Model established by NERC or its successor organization(s). Notwithstanding the foregoing, the OPA continues to have responsibility for integrated resource and transmission planning within Ontario consistent with its objects as specified in the Electricity Act. Moreover, the tasks that embody the principles underlying the Planning Authority's compliance with the applicable Requirements of NERC Reliability Standards are delegated to the OPA.

ii. Regulatory Authority

The various entities in Ontario including the IESO, Ontario energy Board (OEB) and OPA derive their respective powers with respect to transmission planning from provincial statutes and regulations.

The OEB provides regulatory oversight to the IESO and the OPA. The OEB licenses all market participants including the IESO, OPA, generators, transmitters, distributors, wholesalers and retailers. Ontario transmitters seek approval for construction and cost recovery fees from the OEB for transmission projects that may be identified by the IESO or OPA.

b. Summary of Planning Processes

i. Independent Electricity System Operator and the Ontario Power Authority are committed to maintaining a co-operative and mutually supportive relationship in planning processes through coordination and agreements.

In accordance with the market rules, the IESO is required to produce quarterly demand and supply forecasts for the next eighteen months. These forecasts are contained in quarterly "18-Month Outlooks" that are published no later than five business days before the end of each quarter. From market opening in 2002 through 2005, the IESO was obligated to provide a similar reliability assessment looking out 10 years, to be published annually, on or before April 1 of each year. The 10-Year Outlook is being replaced by the Ontario Reliability Outlook (ORO) which will be issued periodically each year on a schedule determined by the IESO. The purpose of the 18-Month Outlooks is to advise market participants of the resource and transmission reliability of the Ontario electricity system, and to assess potentially adverse conditions that might be avoided through adjustment or coordination of maintenance plans for generation and transmission equipment. The purpose of ORO is to continue to provide security and adequacy assessments to the public, as necessary. The information will assist market participants in long-term planning and investment decisions.

Supply forecasts are based on updated confidential information provided to the IESO by market participants. This information is aggregated for publication in order to maintain confidentiality. Due to the significant degree of uncertainty associated with the arrival of new or rehabilitated supply sources, supply forecasts typically assume that only existing and contracted generating units within Ontario will be available in the future, as well as contracted purchases from sources outside of Ontario. The sensitivity of the supply forecast to various other potential supply scenarios is also assessed based on plans submitted to the IESO.

Peak and energy demand forecasts are prepared for Ontario as a whole, and for ten transmission zones within the province, assuming high, median and low economic growth conditions. Economic growth projections are based on a consensus of four major, publicly available provincial forecasts of employment and Ontario housing stock, which are the two key drivers in the demand forecasting model. Weather effects also have a major impact on the demand for electricity, and for this reason, long term demand forecasts are produced for both "normal" weather and "extreme" weather conditions. Normal weather is based on the median of historical weather observations for the past thirty-one years, while extreme weather is based on the most severe weather conditions observed over the past thirty-one years. In addition to these "point" forecasts of electricity demand, the uncertainty due to weather is modeled by assuming a probability distribution about each forecast point based on historical weather observations. The impact of demand-side management programs is forecast based on current plus contracted participation levels. The impact of conservation programs is reflected in the historical demand data used to develop the forecasting model.

Reserve sources of supply are required so that the Ontario electricity demand can be met with a sufficiently high level of reliability. The amount of required reserve is determined by the IESO on a weekly basis, and represents the amount of spare supply capacity required to meet the NPCC Resource Adequacy Criterion. This criterion states that the probability of disconnecting non-dispatchable ("firm") customers due to resource deficiencies will be no more than once in ten years. In practice, an annual Loss of Load Expectation (LOLE) of less than 0.1 day/year is used as the criterion. This calculation is performed using the GE Multi-Area Reliability Simulation model (MARS) which includes planned and random forced outages of both generation and transmission components, transmission system limitations and demand uncertainty due to weather.

Sources of supply in a given week in the future are considered to be adequate if the amount of supply capacity is greater than or equal to the weekly forecast peak demand plus the required reserve for the week. This amount is referred to as the "Reserve Above Requirement" (RAR). Positive values of RAR indicate sufficient supply, and negative RAR values indicate a potential supply deficiency. Supply deficiencies can be addressed through a combination of market participant and IESO actions including the adjustment of generator outage plans, additional participation in demand-side management programs, additional investment in new sources of supply or the rehabilitation of existing supply sources, and the reliance on sources of supply external to Ontario (imports).

The adequacy of the transmission system to deliver power from sources of supply to loads connected to the IESO-controlled grid is assessed in both the 18-Month Outlooks and the 10-Year Outlook (and/or the Ontario Reliability Outlook). The 18-Month Outlooks focus on identifying any planned transmission system outages that negatively impact the reliability of supply to loads. The 10-Year Outlooks and/or ORO focus on identifying future transmission system upgrades that will be required in order to provide a reliable supply to loads connected to the IESO-controlled grid. The Ontario Power Authority will develop an Integrated Power System Plan (IPSP) looking ahead for 20 years in the future. OPA will procure new supply, implement conservation and demand measure. The OPA recently published their advice to the Government on future supply mix options. The IESO retains responsibility for all market and system operations including reliability assessments.

ii. Economic Planning

Economic planning is carried out on a decentralized basis by individual transmission and generation asset owners. The OPA's procurement processes are intentionally structured to achieve the most competitive infrastructure investments possible. Their IPSP is expected to include extensive aspects of economic planning. The IESO publishes comprehensive market and system information to facilitate this process.

iii. Generator/Facility Interconnection

All proposed new or modified connections to the IESO-controlled grid are required to be assessed and approved in advance by the IESO. This includes generation, load and transmission system projects. In addition, distributors are required to obtain IESO approval for generators embedded within their distribution system if the generation facility is rated at 10 MVA or higher. The purpose of this process is to identify any potential negative impacts on the reliability of the integrated power system, and if applicable, to specify the remedial measures necessary to mitigate the potential negative reliability impacts. IESO approval of the proposed new or modified connection is conditional on any required remedial measures being implemented.

In order to ensure fairness and transparency, the IESO's connection assessment and approval (CAA) process is highly-structured and procedure-driven. It begins when a connection applicant has established site control, submits an application to the IESO accompanied by a deposit, and provides the required project information.

Generation projects are assessed in two parts: Part 1 is an assessment of the generation connection in isolation of any other proposed generation projects. Part 2 is initiated when a generator signs a contract with a buyer, or signs a connection cost recovery agreement with a transmitter. When this occurs, the generation project is added to the Committed Generation Projects Queue and a System Impact Assessment (SIA) is performed. The SIA basecase includes all prior generation projects in the queue. The purpose of the SIA is to identify the transmission system enhancements required in order for a proposed generation project to operate at full output. The SIA does not identify transmission system enhancements required to alleviate zonal congestion.

When all required studies and assessments have been completed, the IESO issues a formal System Impact Assessment (SIA) report and Notification of Approval. The IESO connection queue and SIA reports are both published on the IESO web site.

iv. Point-to-Point Transmission Service Request

Physical point-to-point transmission service is not available in the Ontario electricity market; however, Financial Transmission Rights are available for the inter-ties with neighboring jurisdictions. Long-term transmission rights are auctioned quarterly and are valid for a period of one year. Short-term transmission rights are auctioned monthly and are valid for the immediately following month. At least 30 days before each auction, the IESO is required to publish the actual and scheduled hourly flows over each inter-tie during the preceding twelve months, and the hourly transmission transfer capability for each inter-tie during the preceding twelve months. The IESO is also required to identify any transmission transfer capability limits, parallel flow assumptions and other applicable constraints that may limit the number of transmission rights that can be awarded in the transmission rights auction, and the operating assumptions established in respect to the auction.

v. Stakeholder Involvement

The IESO consultation process is built around a strategic advisory body, the Stakeholder Advisory Committee, and numerous Standing Committees and Stakeholder Working Groups, all supported by IESO staff.

All of the IESO's public documentation on market design, market manuals, and public reports are made available on the public web site for comment. A great deal of learning and training material on the market is also made available.

Each individual participant and stakeholder decides the level of its resources to commit to consulting with the IESO, with other members of the same market sector, and with other participants. For different participants, the interest level in different issues can differ widely.

The use of any particular method of consultation depends on the nature of the issue, the time available, the resources available to participants in the process, and the kind of action to be taken. The IESO will fit the method to the issue.

Maximum use is made of web based communications capability. Important face-to-face contact occurs through the Stakeholder Advisory Committee, the Standing Committees, technical conferences, and Stakeholder Working Groups.

c. Allocation of Responsibility

While the OPA is accountable for facilitating transmission infrastructure development necessary to deliver electric energy to consumers reliably through the development of the Integrated Power System Plan, the IESO will continue to provide security and adequacy assessments as necessary.

The IESO produces a short-term operations plan on a quarterly basis. In these 18-month Outlooks, the IESO identifies potentially adverse conditions that might be avoided through adjustment or coordination of maintenance outage plans for generation and transmission facilities. Because the IESO is accountable for the reliable operation of the power system, it is also responsible for establishing policies, standards, criteria and guidelines for short-term reliability purposes. As agreed between the OPA and the IESO, the IESO will act as the Planning Authority for Ontario and will be responsible for the execution of all Planning Authority tasks as specified by the Functional Model established by NERC or its successor organization(s). The IESO will publish the longer range Ontario Reliability Outlook periodically throughout each year. The IESO’s Connection Assessment and Approval (CAA) process allows the IESO to assess the impact of new or modified connections on the reliability of the integrated power system. Last of all, the IESO has the responsibility for inter-jurisdictional co-ordination of short-term planning studies and participates on various international task forces involving other jurisdictions.

The OPA, on the other hand, is responsible for development of the IPSP and is, therefore, responsible for planning of system facilities involving capital investment.

As noted, the OPA will be accountable for producing an overall resource plan having a 20 year horizon. Utilizing plans submitted by current and prospective facility proponents, the OPA will identify the need for generation, transmission or demand management resources that are required to maintain the reliability of the IESO-controlled grid. The OPA will also identify opportunities for the expansion of the transmission system that will allow resources connected to the transmission system to be used more effectively. OPA is required to seek approval of its plan from the provincial regulator, the Ontario Energy Board (OEB). The plan will be the basis for procurement of generation and conservation and demand-side management activities by the OPA, and it will be the basis for construction of transmission by transmission owners in the province.

In parallel, transmitters will be accountable for planning, developing, maintaining and operating their transmission systems to meet the Province's needs, including addressing opportunities for improvements in market efficiency. The OPA is responsible for integrating these plans with each other and with plans for generation and demand resources.

d. Cost Allocation

Ontario's Transmission System Code sets out the obligations of licensed electricity transmitters in relation to the design, construction, management and operation of their transmission systems. It also governs the technical and commercial relationships between licensed electricity transmitters and their directly connected customers. The Ontario Energy Board (OEB) has recently proposed a number of revisions to the Code. For example, the revised Code requires loads and generators to make a capital contribution for new or modified transmitter-owned connection facilities. Network enhancement costs incurred in establishing new or modified connections are to be paid by all ratepayers, on the grounds that network assets primarily benefit all Ontario electricity consumers, subject to a few exceptional circumstances where it is more appropriate to allocate some or all network enhancement costs to a transmission customer.

While other ISOs/RTOs are struggling with the principle of beneficiary pays – i.e., allocating among customers within an RTO the cost of new transmission facilities that are built in one area of the RTO but provide benefits to customers in another area - Ontario has chosen an approach that largely avoids this issue. Because Ontario ratepayers pay a uniform price and congestion is paid through an uplift charged to all market participants, the cost of any proposed transmission investments for improving market efficiency would be socialized across all ratepayers.

e. Relation to Reliability Councils

The IESO is a member of the Northeast Power Coordinating Council (NPCC). The Ontario Market Rules specify adherence to the standards established by standards authorities including NPCC and the North American Electric Reliability Council (NERC). The IESO, OPA, and all Ontario market participants must therefore act in a manner consistent with meeting these mandatory and enforceable standards. The IESO, as the Ontario Control Area operator and Reliability Coordinator, is responsible to NPCC for meeting all of these standards. The IESO in turn holds all Ontario entities responsible for meeting their respective requirements.

f. Definition of Transmission

"IESO-controlled grid" means the transmission systems with respect to which, pursuant to Operating Agreements or otherwise between the IESO and transmitters, the IESO has authority to direct operations. Ontario legislation defines transmission system as a system for transmitting electricity at voltages of more than 50kV.

The Ontario Energy Board's Transmission System Code further defines "transmission system" as follows:

- For distributors and consumers, the transmission system ends at, and includes, the load side of low-voltage feeder breakers;
- For generators, the transmission system typically ends at the first disconnection switch (not included) of the synchronizing breaker and/or step-up transformer combination;

ISO-NE

ISO New England Inc. is the private, nonprofit entity that serves as the regional transmission organization for New England under the jurisdiction of the Federal Energy Regulatory Commission. In its capacity as the RTO for New England, the ISO-NE has the responsibility to protect the short-term reliability of the control area.

ISO-NE works with stakeholders throughout New England to develop fair and efficient wholesale electricity markets and to plan a reliable bulk power system. Stakeholders include, but are not limited to wholesale market participants, state public utility commissions, and other interested representatives from state agencies in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut.

ISO-NE meets the electricity demands of the region's economy and people by fulfilling three primary responsibilities:

- Minute-to-minute operation of New England's bulk electric power system, providing centrally dispatched direction for the generation and flow of electricity across the region's interstate high-voltage transmission lines, thereby ensuring the constant availability of electricity for New England's residents and businesses.
- Development, oversight, and fair administration of New England's wholesale electricity marketplace, through which bulk electric power has been bought, sold, and traded since 1999. These competitive markets provide positive economic and environmental outcomes for consumers and improve the ability of the power system to efficiently meet ever-increasing demand.
- Management of the comprehensive planning processes for the bulk electric power system and wholesale markets, which address New England's future electricity needs.

The ISO-NE’s Board of Directors and its 400 employees have no financial interest or ties to any company doing business in the region's wholesale electricity marketplace.

a. Legal Authority

The ISO administers the New England energy markets and operates the New England bulk power system pursuant to the ISO New England Inc. Transmission, Markets, and Services Tariff (ISO-NE Tariff) and the transmission operating agreements (TOA) with each New England transmission owner.

i. Statutory Authority

Any interconnection customer that proposes to interconnect its generating facility, or to materially change the capacity of an existing generating unit interconnected to the administered transmission system, must follow the interconnection procedures set forth in Schedule 22 of the ISO New England Open Access Transmission Tariff (OATT). The federally approved TOAs and associated RTO governing documents allocate the ISO and New England transmission company responsibilities.

ISO-NE is organized as a non-stock corporation under the laws of the State of Delaware. ISO-NE has been approved as an RTO by the FERC pursuant to the Federal Power Act.

ii. Regulatory Authority

Created in 1997, the ISO-NE originally functioned as the Independent System Operator for the six-state New England region pursuant to a FERC-approved open access transmission tariff. Effective February 1, 2005, ISO-NE was approved as the RTO for the New England region. As the RTO for New England, ISO-NE is responsible for the day-to-day reliable operation of New England's bulk power system, the oversight and administration of the New England region's wholesale electricity markets, and management of a comprehensive regional bulk power system planning process. ISO-NE provides these services under its FERC-approved tariff to ISO participants under the Market Participants Services Agreement and non-ISO participant transmission-only customers through the Transmission Services Agreement.

b. Summary of the Planning Process

Overview of System Planning

Generation, demand, and transmission must all be considered when planning the New England electricity system. With the continued growth in electricity load projected for the region, and with several major portions of New England, including Greater Connecticut, Greater Southwest Connecticut, Boston, and Vermont, facing serious reliability issues, proper planning is required to identify needed system improvements and maintain long-term system reliability.

The critical inputs to the planning process are load forecasts, projections of generation and distributed resources that reduce load, and an assessment of the performance of the overall system, including the transmission system that moves power to where it is needed. Also vital in the planning process is to account for the necessary lead times for licensure and construction. The Regional System Plan[3] (RSP) accounts for the addition of generating units and demand-response resources (i.e., resources made available when customers reduce their electricity consumption in response to reliability and price), potential resource retirements, and load growth, with due consideration of the system's economic performance and impact on system-wide air emissions. As is evident in the RSP, electrical problems and solutions can—and in many cases do—cross state and operating-company boundaries.

As the Regional Transmission Organization, ISO New England leads the annual planning effort through an open stakeholder process. With input from the Planning Advisory Committee[4] (PAC) and other stakeholders, and technical assistance from the transmission owners, the ISO analyzes and plans for the reliability and adequacy of the New England bulk power system as an integrated whole. This ensures that system modifications made to one part of the system, including newly interconnected generating units, will not have an adverse impact on another part of the system.

Planning Criteria

The North American Reliability Council, Northeast Power Coordinating Council, and NEPOOL all require the studies conducted for the RSP to be consistent with their planning

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[3] Prior to the formation of the RTO, this report was called the Regional Transmission Expansion Plan or RTEP.

[4] The PAC is comprised of electric market participants, representatives from governmental entities, and consultants. Prior to the formation of the RTO, this committee was called the Transmission Expansion Advisory committee, or TEAC.

criteria and procedures. These criteria and procedures include prescriptive guidelines for enhancing resource adequacy and transmission performance necessary for ensuring a reliable bulk electric power system design.

The Planning Process

As illustrated in the figure below, planning is an ongoing cyclical effort. It is continually impacted by changing load forecasts, changing fuel costs, new generation that has come on-line and generation that has gone off-line, new transmission projects, varying levels in demand, and firm purchases and sales. In this regard, the RSP is a continuum of past Regional Transmission Expansion Plans (RTEPs), although the RSP is broader in scope than the RTEP reports.[5] The RSP analyses determine the system's capability to reliably serve load over the 10-year period and the need for new resources and transmission improvements, and it addresses the needs of the electrical system as a whole over the planning period, not just the needs for the transmission system. Through the many PAC reviews during the year, the RSP studies evolve. The studies supporting the RSP often do not follow the calendar year of RSP or RTEP reports, which represent a snapshot of their status.

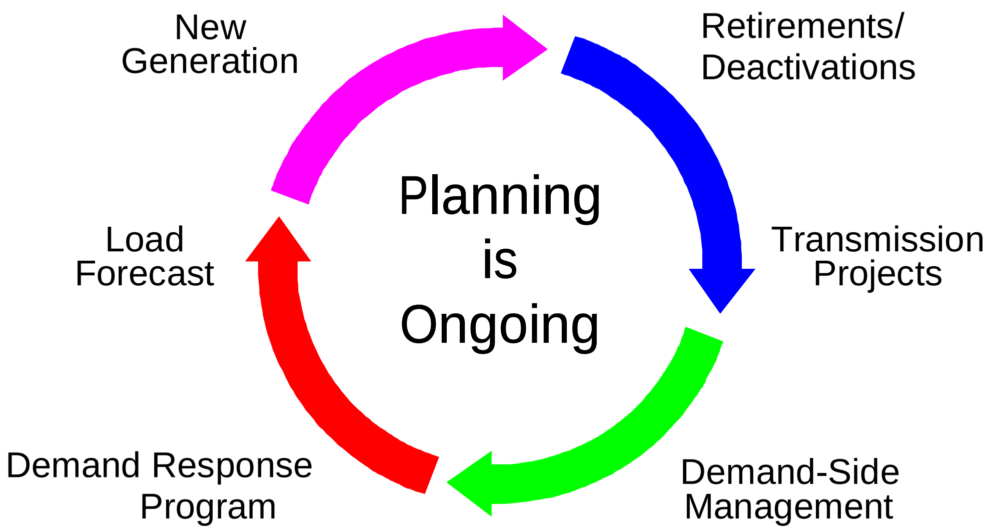

Figure 1: Planning

Planning Studies

Since New England is a tightly integrated system, the ISO analyzes and plans for the reliability and adequacy of New England's bulk electric power system as a single system. To capture all system changes and obtain a comprehensive assessment of the performance of the power system, the ISO conducts a wide variety of analyses, all of which must be considered during the RSP planning process. Each study has individual merit and a specific purpose, but no single analysis provides the overall picture. To determine overall system performance, the results of all studies must be reviewed from an integrated perspective.

Although the ISO simulates the system under various conditions to examine corresponding impacts, in some RSP analyses, the ISO employs the simplified model of the transmission system that includes the system's subareas. The simplified model can accommodate certain

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[5] RTEP reports can be found in the archives at: <http://www.iso-ne.com/trans/rsp/2005/index.html>.

simulations of the projected system's performance and capture potential limitations in the transmission system.

The results of the analyses that use the simplified model of the subareas do not capture system constraints within the subareas, but rather reflect approximate transfer capabilities between them. As such, transportation modeling results based on the subareas should be considered "best-case" results. They are suitable for resource-reliability assessments, but not for detailed transmission analyses, which are also necessary to more accurately capture system performance within and between the RSP subareas.

In general, the modeling of the electricity system of New England and its subareas depends on a variety of assumptions regarding the in-service dates for new units, generation availabilities, fuel costs, timing of transmission upgrades, load forecasts, and transactions with neighboring control areas. A major part of the annual RSP process includes updating the modeling assumptions used to reflect changed circumstances.

i. Reliability Planning

The following discussion of ISO New England's planning process encompasses planning the region's system additions and improvements to meet the applicable reliability criteria. It describes ISO New England's planning processes for 1) determining the amount of resources needed for the future 10-year planning horizon, 2) analyzing resource location and operating characteristics, and 3) conducting transmission studies.

1. Determining the Amount of Resources Needed

The ISO conducted loss-of-load expectation (LOLE) and operable capacity (OC) analyses to determine the amount of resources the system will require to serve load from 2006 to 2014.These analyses are needed to assess compliance with NPCC and RTO planning criteria that require the system to have sufficient supply to serve load.

Loss-of-Load Expectation

The ability of generation to serve load may be influenced by several factors, including generator outage rates, lack of fuel diversity, distribution of load throughout a region, penetration of demand-response programs that use conservation measures and distributed resources, and transmission constraints.

A loss-of-load-expectation analysis is a probabilistic measure of resource adequacy. It uses the probability of generator forced outages and load levels to calculate the amount of loss, or disconnection, which can be expected of the system during weekday peak-demand periods under various weather conditions and a range of resource availabilities. Although LOLE analyses use a limited model of the transmission system and operational constraints, these analyses are extremely important because they identify the amount of resources needed to meet the established resource planning reliability criterion. ISO New England uses the NPCC criterion that a power system requires enough installed capacity to prevent the disconnection of non-interruptible customers more than 1 day in 10 years (or 0.1 day per year).

Operable Capacity Analysis

An operable capacity analysis is a deterministic analysis of resource adequacy that accounts for both the 50/50, and 90/10 load forecasts. This method essentially provides a day-to-day “look” at operational requirements by identifying the operable capacity requirements for the total system and by load pockets, which recognize the specific characteristics of each area.[6] The 90/10 forecast is used for load pockets, consistent with NERC, NPCC, and RTO planning procedures, because smaller regions or load pockets typically have more limited transmission capability, fewer options for emergency actions, and the need to protect against situations that could cause cascading outages.

2. *Analyzing Resource Location and Operating Characteristics*

Several analyses provide information on the desired location and operating characteristics of generating resources needed to supply load. These analyses include those that assess reliability, the diversity of the New England mix of fuels, environmental air emission issues, and the requirements for Renewable Portfolio Standards (RPS).[7]

Fuel Diversity

Interruptions in fuel supply can create capacity and energy deficiencies. The RSP summarizes lessons learned from dealing with the period of extremely cold weather that took place in January 2004 (January 2004 Cold Snap), when both the demand for gas and electricity peaked simultaneously, and from the efforts by ISO New England and the natural gas industry to prepare for future cold snaps by increasing fuel flexibility.[8] To better understand the natural gas industry, the report summarizes analyses of the availability of and need for natural gas supply, storage, and transport. The RSP report also summarizes reliability risks of fuel shortages by calculating the LOLE for various fuel-shortage scenarios and determines the amounts of dual or alternate fuels required to ensure reliable service to load. A longer-range look at fuel diversity is also provided.

Air Emissions Issues

The RSP report includes the results of simulations of regional air emissions, sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2), attributed to the production of electricity over the next 10 years. The simulations were done for various fuel scenarios. The RSP also presents information on the impact of a likely CO_2 emissions cap on electricity generators to be implemented during the 10-year planning period, the role of distributed resources, and the requirements for meeting Renewable Portfolio Standards. These results provide information for market participants on the amount, type, and location of needed resources.

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[6] Load pockets are areas of the system where the transmission capability is not adequate to import capacity from other parts of the system, and load must rely on local generation.

[7] RPS are state-mandated requirements for competitive retail electricity providers to supply a portion of their energy from renewable resources.

[8] For additional information on January 2004 Cold Snap events, see <http://www.iso-ne.com/special_studies/January_14_-_16_2004_Cold_Snap_Reports/>.

3. *Conducting Transmission Studies*

Transmission studies are necessary to ensure that system reliability can be maintained in conformance with NERC, NPCC, and ISO criteria, procedures, and guidelines. These studies are also conducted to evaluate the performance of economic, elective, and merchant transmission upgrades. ISO New England uses a comprehensive model of the power system for conducting transmission studies that includes data on all generators, transmission facilities, and loads. Simulations address physical issues, such as thermal loading, minimum voltage, voltage regulation, transient stability, dynamic oscillations, harmonics, and short-circuit interrupting capability. System assessments and planned improvements must also be fully coordinated with neighboring control areas.

ii. Economic Planning

ISO New England's planning process focuses on planning the economical transmission improvements needed to meet the reliability criteria and to minimize congestion costs on the system. Alternative resources are also taken into account during the planning process, which may be proposed as market responses to resource needs.

iii. Generator/Facility Interconnection Inclusive of Deliverability

The administered transmission system is comprised of pool transmission facilities (PTF), non-PTFs and the Maine Electric Power Company transmission facilities. Pool Transmission Facilities are transmission facilities that meet certain criteria in the ISO Open Access Transmission Tariff and that are owned by transmission owners which have signed the Transmission Operating Agreement with ISO New England Inc. Examples of facilities considered to be non-PTFs include radial tap lines to local load; and radial connections or connections from a generating station to a single substation or switching station on the PTF For lines that loop from two geographically separate points on the PTF, the supply to a load bus from the PTF are considered to be PTFs.; For lines that loop from two geographically separate points on the PTF, the connections between a generator bus and the PTF are considered to be pool transmission facilities, as well.

The ISO administers the interconnection procedures, which include procedures for:

- Submitting and validating interconnection requests
- Establishing scoping meetings with the affected parties
- Scoping and performing Interconnection Studies
- Negotiating and filing Interconnection Agreements

Four types of Interconnection Studies, as follows, provide for the interconnection procedures:

- Interconnection Feasibility Study
- Interconnection System Impact Study
- Interconnection Facilities Study
- Optional Interconnection Study

The interconnection procedures set forth the requirements for the scope and timeframe for performing each type of study and other regional information. The Interconnection Feasibility Study may be performed as a separate and distinct study or as part of the Interconnection System Impact Study, which is the only required study under the interconnection procedures. The interconnection customer may waive the Interconnection Facilities Study and elect an expedited interconnection. ISO-NE is a party to the agreements included in the optional Interconnection Study, along with the interconnection customer and the interconnecting transmission owner.

The interconnection customer proposing the new or materially changed generating unit is responsible for the costs of generator interconnection-related upgrades in accordance with Schedule 11 of the ISO OATT.

ISO New England has only one interconnection product, the Minimum Interconnection Standard (MIS). Under MIS, the generating unit must interconnect in a manner that avoids any significant adverse effect on system reliability, stability, and operability, and it must prevent the degradation of transfer capability for interfaces affected by the unit.

iv. Point-to-Point Transmission Service Request

ISO-NE does not offer point-to-point transmission service internal to New England. However, it does require point-to-point transmission service for transactions that wheel through or out of the New England Control Area. Advance reservations for such transactions over the PTFs are not required. When a real-time external transaction that exports energy out of or wheels through the New England Control Area is submitted by a transmission customer and is scheduled in the Real-Time Energy Market, the submission is deemed a request for through or out service. The ISO automatically generates a reservation for through or out service equal to the transaction's schedule, which is the basis for the amount of reserved capacity. Advance reservations may be required for service over the ties that are non-PTFs, such as the Cross Sound Cable, the HQ Interconnection, and the Maine Electric Power Company transmission facilities.

v. Stakeholder Involvement

ISO works with stakeholders in New England's wholesale electricity markets including the NEPOOL Participants Committee and the technical committees (Markets, Reliability, Transmission). ISO also works with state representatives through the New England Conference of Public Utilities Commissioners (NECPUC). ISO conducts an open and ongoing stakeholder process for development of the Wholesale Markets Plan (WMP) and the Regional System Plan. The Planning Advisory Committee provides regular opportunities for stakeholder input to the development of the RSP.

c. Allocation of Responsibility – ISO/RTO versus TO

ISO began operation as an RTO on February 1, 2005. As the RTO, ISO New England exercises day-to-day operational control of the transmission system under agreements with existing transmission companies and serves as the single point-of-control to effectively maintain reliability and preserve the integrity of the bulk power system on a daily basis and in emergency situations. Additionally, the ISO acts as the reliability authority for the New England transmission system.

d. Cost Allocation

FERC approved a new transmission cost allocation (TCA) process for New England in December 2003, now in effect under Schedule 12 of the ISO-NE Transmission Tariff and ISO-NE Planning Procedure No. 4 (PP4), *Procedure for Pool-Supported PTF Cost Review*, which provide for cost allocation treatment of upgrades, modifications, or additions to the transmission system in New England on and after January 1, 2004.

The tariff states, "Upgrades, modifications or additions to the New England Transmission System shall be categorized by the ISO, with advisory input from the Reliability Committee and the Planning Advisory Committee, as appropriate. A list of categorized Transmission Upgrades shall be made part of each annual and interim Regional System Plan (RSP)." The tariff provides for the treatment of generator interconnection-related upgrades, elective transmission upgrades, regional benefit upgrades, local benefit upgrades, localized costs, and projects identified in the 2002 RTEP. Generally, transmission projects that provide benefits to the region are eligible for cost support through the tariff, while projects, or elements of projects that do not provide regional benefits, are not eligible for regional cost support. With advisory input from the NEPOOL Reliability Committee, ISO-NE determines whether any localized costs need to be excluded from pool-supported PTF costs. (Merchant transmission facilities are not eligible for funding under the tariff.)

Eligible transmission projects must operate at or above 115 kV and be part of the regional network and be identified as either a reliability or economic upgrade in the RSP. Eligible projects must obtain reliability approval for interconnecting to the system prior to TCA approval. The NEPOOL Reliability Committee reviews TCA applications and provides advisory input to the ISO-NE, which makes a final decision on such applications.

Stakeholders in New England were involved in the development of the TCA process and participate in public meetings to review larger, more complex transmission projects seeking regional cost support through the tariff.

e. Relation to Reliability Councils

ISO-NE is a member of the Northeast Power Coordinating Council and an active member of its committees and stakeholder process.

f. Definition of Transmission (PTF and RTO responsibilities)

Definition of PTF

The ISO OATT specifies that the transmission facilities required to allow energy from significant power sources to move freely on the New England Transmission System must be rated 69 kV or above. These facilities include the following:

- All transmission lines and associated facilities owned by participant transmission owners (PTOs) rated 69 kV and above, except for lines and associated facilities that contribute little or no parallel capability to the PTF
- Parallel linkages in network stations owned by PTOs (including substation facilities, such as transformers, circuit breakers, and associated equipment) interconnecting the lines that constitute PTFs
- Certain connections to a PTO's transmission and distribution system
- Rights-of-way and land owned by PTOs required for the installation of facilities that constitute PTF under the first three bullet points listed above.

Those lines and associated facilities required to serve local load only; generator leads, which are radial transmissions from a generation bus to the nearest point on the PTF; lines normally operated open; and lines and associated facilities classified as merchant or other transmission facilities are not considered to be PTFs.

Responsibilities Regarding PTFs

Under the ISO-NE OATT, the ISO must review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTFs, and it must prepare and keep current a schedule or catalogue of PTF facilities. Also under the OATT, the PTOs determine their annual transmission revenue requirements based on each PTO's costs with respect to PTFs, including costs attributable to those PTOs deemed to own or support PTFs.

Midwest ISO

The Midwest ISO was approved as the nation's first RTO in 2001. The Midwest ISO manages one of the world's largest energy markets using security constrained economic dispatch of electricity. In addition, the organization administers Day-Ahead, Real-Time and Financial Transmission Rights markets as well as Locational Marginal Pricing at over 1,400 nodal locations. Consistent with FERC Order No. 2000 and its Midwest Markets Tariff, the Midwest ISO utilizes a market-based platform for grid congestion management.

Membership in the organization is voluntary. The Midwest ISO acts in close cooperation with the 15 states and the province of Manitoba, where it operates 97,000 miles of transmission lines. The organization is responsible for ensuring fair access and reliable operation of a system with a peak load of 119,000 MW and 131,000 MW of generation. The non-profit organization was founded in 1998, is governed by an independent Board of Directors, and is headquartered in Carmel, Indiana with an operations center in St. Paul, Minnesota.

The current transmission owning members of the Midwest ISO are: Alliant Energy Corporation; American Transmission Company, LLC ; Aquila, Inc.; AmerenCILCO; AmerenIP; AmerenUE; AmerenCIPS; Cincinnati Gas & Electric Company; PSI Energy, Inc.; Union Light Heat & Power Company; City of Columbia, MO; City Water, Light & Power (Springfield, Illinois); FirstEnergy's American Transmission Systems, Inc.; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company; Louisville Gas and Electric Company; Kentucky Utilities Company; Lincoln Electric System; Michigan Electric Transmission Company, LLC; Michigan Public Power Agency; Minnesota Power, Inc. and its subsidiary, Superior Water, Light and Power Company; Montana-Dakota Utilities Company; Northern Indiana Public Service Company; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Vectren Energy; Wabash Valley Power Association, Inc.; Xcel Energy, Inc.;

In its role as RTO, the Midwest ISO ensures that the transmission system under its operational control is planned to reliably and efficiently meet the needs of the transmission customers it serves. Transmission system planning within the Midwest ISO is performed in accordance with the planning protocol of Appendix B to the Midwest ISO Transmission Owners Agreement[9], and with the Transmission and Energy Market Tariff and its Attachments, each of which can be found at http://www.midwestiso.org/.

a. Legal Authority

i. Statutory Authority

The Midwest ISO is organized as a non-stock, not-for-profit corporation, pursuant to Title 8, Chapter 1 of the laws of the State of Delaware.

[9] Agreement Of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation

ii. Regulatory Authority

The Midwest ISO operated exclusively for the promotion of social welfare, in furtherance of the public policy reflected in the Orders of the FERC approving the Transmission Owner's Agreement and the formation as an RTO.

b. Summary of Planning Process

The Midwest ISO produces a comprehensive regional plan referred to as the Midwest ISO Transmission Expansion Plan, or MTEP. MTEP is produced at least biennially, and provides recommendations to the Midwest ISO Board of Directors for both reliability needs and information to market participants and other interested parties about additional expansions with potential commercial benefits. The MTEP is a combination bottom-up and top-down process. Ongoing reliability-based upgrades from the generation interconnection and long-term firm transmission delivery service processes are rolled together with local area transmission plans developed by transmission owners to meet local load growth needs. The Midwest ISO then evaluates these combined plans for effectiveness in meeting both reliability and commercial needs. Considerations for effectiveness include adherence to reliability standards, cost effectiveness of non-transmission solutions such as redispatch, demand and supply side solutions, and availability and access to low cost resources. Solutions of regional scope are considered for effectiveness in meeting the broad long-term needs of all stakeholders.

Reliability requirements in MTEP are identified through a five-year planning horizon. MISO coordinates the work of Regional Study Groups that may consider expansions needed in longer-term horizons.

Reliability evaluations are based on NERC, Regional, and Transmission Owner reliability standards and are consistently applied in all planning analyses to ensure efficient and reliable service and fair and non-discriminatory access to all transmission customers

i. Reliability Planning

Reliability Projects are identified either in the periodically performed Baseline Reliability Study, or in Facilities Studies associated with the request processes for new transmission access. Transmission access includes requests for both new transmission delivery service and new generation interconnection service.

Baseline Reliability Projects are Network Upgrades identified in the MTEP as required to ensure that the Transmission System is in compliance with applicable reliability requirements of NERC, regional reliability councils, or successor organizations, Transmission Owners' planning criteria filed with federal, state, or local regulatory authorities, and applicable federal, state and local system planning and operating reliability criteria. Baseline Reliability Projects include projects that are needed to maintain reliability while accommodating the ongoing needs of existing Transmission Customers. The Midwest ISO planning staff collaborates with transmission owning members and with other transmission providers to develop appropriate planning models that reflect expected system conditions for the planning horizon. Models reflect the projected load growth of existing network customers and other transmission service and interconnection commitments, and include any transmission projects identified in Transmission Service Agreements or Interconnection Agreements that are entered into in association with requests for transmission delivery or interconnection service, as determined in Facilities Studies associated with such requests. The Midwest ISO tests the MTEP for adequacy and security based on all applicable criteria, and under likely and possible dispatch patterns of Generation Resources within the Midwest ISO system and of external resources, and has as its objective to produce an efficient expansion plan that includes all Baseline Reliability Projects determined by the Midwest ISO to be necessary through the planning horizon of the MTEP. The Midwest ISO then seeks the approval of the Midwest ISO Board of Directors for each MTEP published.

New Transmission Access Projects are Network Upgrades identified in Facilities Studies and agreements pursuant to requests for transmission delivery service or transmission interconnection service under the Tariff. New Transmission Access Projects include projects that are needed to maintain reliability while accommodating the incremental needs associated with requests for new transmission or interconnection service, as determined in Facilities Studies associated with such requests. When determining the need for New Transmission Access Projects the Midwest ISO considers the Baseline Reliability Projects already determined to be needed in the most current MTEP, as well as any other base-case needs not associated with the request for new service that may be identified during the impact study process. Any identified base-case needs determined in the impact study process that are not a part of the Baseline Reliability Projects already identified in the most current MTEP become new Baseline Reliability Projects and are be included in the next MTEP. New Transmission Access Projects identified in Facilities Studies and agreements pursuant to requests for transmission delivery service or transmission interconnection service under the Tariff are be included in the next MTEP.

ii. Economic Planning

The Midwest ISO planning protocol outlined in Appendix B to the Transmission Owner's Agreement requires that the Midwest ISO identify expansions critical to support competition in bulk power markets. The Midwest ISO meets this requirement by identifying economic projects, which are Network Upgrades that are proposed by the Midwest ISO or by Market Participants as beneficial to one or more Market Participants but that are not determined to be Baseline Reliability Projects or New Transmission Access Projects. Economic projects may benefit Market Participants by supporting competition in bulk power markets, by expanding trading opportunities, or alleviating congestion beyond that achieved by Baseline Reliability Projects or New Transmission Access Projects, or that otherwise provide sufficient benefits as determined by the Midwest ISO to justify inclusion in the MTEP. After the Midwest ISO has initially identified the Baseline Reliability Plan, the Midwest ISO, Transmission Owners, ITC's, Market Participants, or regulatory authorities may propose to include additional economic projects in the MTEP. The Midwest ISO performs a case-by-case identification of the potential benefits associated with proposals for economic projects (i.e., reliability, economic, policy, and economic development) in order to facilitate the potential inclusion of such projects into the MTEP. At the present, Economic projects will be included in the MTEP only after cost responsibility for such projects has been determined and after Board approval.

iii. Generator/Facility Interconnection Inclusive of Deliverability

Generator interconnection processes are contained in Attachment X to the Midwest ISO Tariff. The interconnection process includes an initial application to the Midwest ISO to enter into a project queue as well as steps to successfully completing Feasibility, System Impact, and Facility Studies prior to execution of an Interconnection Service Agreement.

The present Midwest ISO interconnection process follows closely the FERC pro-forma procedures of Order 2003. These procedures permit the Interconnection Customer to be interconnected as an Energy Resource or as a Network Resource.

Network Resource Interconnection service requires a deliverability test, in addition to basic reliability tests to ensure stability and short circuit limits are maintained. Deliverability of Network Resources is an essential element of the Midwest ISO resource adequacy requirements included in the market Tariff. Deliverability ensures that the aggregate of network resources can be used to deliver energy to the aggregate of load. Once a network resource is established as deliverable, it can be applied by any load serving entity towards capacity reserve requirements provided that firm contractual arrangements are established between the load and the generator.

The load serving capability of the transmission system is established by the combination of the generator deliverability tests described above, and Load Deliverability tests that are performed as a part of the cyclic MTEP Baseline Reliability evaluations. Deliverability to Load ensures that, within accepted probabilities, energy will be able to be delivered to designated regional load/generation areas, regardless of cost, from the aggregate of capacity resources available to the Midwest ISO.

iv. Point-to-Point Transmission Service Request

The Midwest ISO offers both Firm and Non-Firm Transmission Service to Eligible Customers that reserve service for the transmission of capacity and/or energy from Point(s) of Receipt to Point(s) of Delivery.

The minimum term of Long Term Firm Point-To-Point Transmission Service is one year and the maximum term is specified in a Service Agreement. The term of Short-Term Firm Point-To-Point transmission Service is one day, one week, or one month.

Non-Firm Point-To-Point Transmission service is available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point –To-Point Transmission Service is entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies may be greater than one month.

From a planning perspective, requests for long-term firm transmission service are subject to System Impact Study procedures.

v. Stakeholder Involvement

The Midwest ISO conducts an open planning process with input and advice from stakeholders through multiple forums at MISO. These forums included the Organization of Midwest ISO States (OMS), Advisory Committee, Planning Advisory Committee, Planning Support Group, and Expansion Plan Group. The scope of issues to be addressed in each plan, other than the core Baseline Reliability studies, are reviewed with these stakeholder groups to best meet stakeholder needs. These groups not only help drive the scope and structure of the expansion plan effort, but they provide assistance with data, information, plans, assessments, and reviews and critiques of the MTEP process and product.

c. Allocation of Responsibility - RTO vs. TO

The division of responsibility between the Midwest ISO and the Owners in maintaining the reliability of the Transmission System is set forth in more detail in Appendices B and E to the Transmission Owner's Agreement. In general the RTO is responsible for secure and reliable operations of, and for the coordinated planning of the system as required to meet applicable operating and planning standards. The Midwest ISO engages in such planning activities as are necessary to fulfill its obligations under the Agreement and the Transmission Tariff. Such planning conforms to applicable reliability requirements of the North American Electric Reliability Council, applicable regional reliability councils, or any successor organizations, each Owner's specific reliability requirements and operating guidelines, and all applicable requirements of federal or state laws or regulatory authorities. Such planning seeks to minimize costs, consistent with the reliability and other requirements set forth in the Agreement.

To fulfill their roles in the collaborative process for the development of the Midwest ISO Plan, the Owners develop expansion plans for their transmission facilities while taking into consideration the needs of (i) connected loads, including load growth, (ii) new customers and new generation sources within the Owner's system, and (iii) known transmission service requests. Any plans that call for modifications to the Transmission System which would significantly affect ATC must be approved by the Midwest ISO before being implemented.

Owners participate in the integration and testing of the Midwest ISO Plan. Owners serve on Ad Hoc Planning Committees established by the Midwest ISO staff to respond to transmission service and interconnection requests and other matters. Studies are performed either by the Midwest ISO staff, or contractors to the Midwest ISO, which may include the Transmission Owners under the same contractual terms as any other contractor.

d. Cost Allocation

At the time of completion of the MTEP 05, cost responsibility for load growth driven projects is in accordance with Attachment N to the tariff and the Transmission Owners Agreement, which, in general assigns the costs for such upgrades to the local Transmission Owner constructing the upgrade. Costs for generator interconnection driven upgrades are in accordance with Attachment X to the tariff and are determined at the time of execution of each individual interconnection agreement. Attachment X presently applies the Order 2003 pro-forma crediting provisions, wherein the interconnection customer initially funds network upgrades, and the Transmission Owner then repays the generator as service begins to be taken from the generator. This policy is in transition, however, as it is not well suited to the Midwest ISO regional network service tariff and revenue distribution policies. Costs associated with network upgrades required to accommodate long-term firm transmission delivery service requests are paid for by the transmission service customer via a direct monthly fixed charge, under the terms of Attachment N to the Tariff.

Together with stakeholders, the Midwest ISO has been developing a transmission pricing policy and additions to the planning protocol contained in the Transmission Owners Agreement. This policy and protocol is expected to involve a form of regional cost sharing for transmission expansions that better reflects the usage and benefits of transmission under the Transmission and Energy Markets Tariff.

e. Relation to Reliability Councils

The Midwest ISO and members voluntarily participate in the applicable Electricity Reliability Coordinating Councils - ECAR, MAIN, and MAPP – as well as the broader governing activities of the NERC itself. In general the reliability councils are responsible for monitoring compliance of all members, including the RTO, to NERC and Regional operating and planning standards. The reliability councils also perform various seasonal and longer-term reliability evaluations under the terms of their forming agreements and in accordance with NERC standards. The Midwest ISO and the regional councils exchange reliability information and data, and assessment results and continue to work to eliminate duplication of efforts where practical.

f. Definition of Transmission

The following transmission facilities of the Owners constitute the Transmission System for which the Midwest ISO is responsible for operating and planning by the terms of the TO Agreement: (i) all networked transmission facilities above 100 kV; and (ii) all networked transformers whose two (2) highest voltages qualify under the voltage criteria of item (i).

Network transmission facilities (including terminal equipment) are (i) transmission elements capable of carrying power in both directions for sustained periods, and (ii) components that are connected to such transmission facilities and are used for voltage or stability control of the Transmission System, including shunt inductors, shunt capacitors, and synchronous condensers. Appendix H to the Agreement identifies the facilities that constitute the Transmission System for which the Midwest ISO shall have operating and planning responsibility.

The Midwest ISO may direct the Owners to assign Non-transferred Transmission Facilities to its control as part of the Transmission System, subject to obtaining any necessary approvals of federal or state regulatory authorities, when such action is determined to be necessary to relieve a constraint or for security purposes. The Midwest ISO also may require that Owners take back control of facilities included in the Transmission System subject to any such necessary approvals.

NYISO

The New York Independent System Operator (NYISO) is a FERC-approved Independent System Operator (ISO). Organized as a nonprofit corporation, the NYISO coordinates the transmission of electricity over the transmission facilities of the participating Transmission Owners[10] (TOs) serving all of the State of New York.

Planning both resource and transmission adequacy on a regional basis is one of the primary functions of the NYISO. The NYISO implements this function pursuant to the Comprehensive Reliability Planning Process (CRPP) set forth in Attachment Y of the NYISO Open Access Transmission Tariff (OATT) as well as the NYISO/TO Agreement, the NYISO Agreement and the NYISO/NYSRC[11] Agreement. These Agreements and the OATT are available on NYISO's web site at www.nyiso.com .

a. Legal Authority

i. Statutory Authority

The NYISO is incorporated as a as a not for profit corporation under the laws of the state of New York to engage in such business activities as are required to carry out the terms of NYISO Open Access Transmission Tariff (OATT), the Market Administration and Control Area Services Tariff, as well as the NYISO/TO Agreement, the NYISO Agreement and the NYISO/NYSRC Agreement. Specifically, the NYISO CRPP is subject to the federal statutory requirements under the Federal Power Act and implementing regulations and orders of the FERC.

ii. Regulatory Authority

At the outset, the NYISO's FERC-approved Tariff and formation Agreements called for the NYISO to perform planning and reliability assessments to ensure conformance with NERC, NPCC and NYSRC criteria. The NYISO also had the responsibility to conduct reliability studies with respect to interconnection requests or requests for firm transmission service. The ISO Agreement provided for the preparation of a consolidated Transmission Plan which was a compilation of the TO's transmission projects and any approved merchant facilities or interconnection –related upgrades.

In August 2004, the NYISO filed a proposal with FERC to establish a formal, long-range Comprehensive Reliability Planning Process (CRPP) under the direction of the NYISO. On December 28, 2004, FERC approved the NYISO proposal, thereby providing the authority, under the OATT, for the NYISO to analyze system resource adequacy and transmission reliability needs over a ten year period and to request the appropriate TO to provide a regulated backstop if no market-based solution appears. As part of this

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[10] The eight major TOs include CENTRAL HUDSON GAS & ELECTRIC CORPORATION ("Central Hudson"), CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. ("Con Edison"), NEW YORK STATE ELECTRIC & GAS CORPORATION ("NYSEG"), NIAGARA MOHAWK POWER CORPORATION ("NMPC"), ORANGE AND ROCKLAND UTILITIES, INC. ("O&R") and ROCHESTER GAS AND ELECTRIC CORPORATION ("RG&E"), all corporations organized under the laws of the State of New York, and POWER AUTHORITY OF THE STATE OF NEW YORK ("NYPA") and LIPA a subsidiary of the Long Island Power Authority, a corporate municipal instrumentality of the State of New York.

[11] NYSRC is the New York State Reliability Council

proposal, the FERC also approved a separate Agreement between the NYISO and the NYTOs which addresses the rights and responsibilities of the Transmission Owners with respect to the CRPP. While the CRPP is conducted in an open stakeholder forum, subject to the normal NYISO governance process, the NYISO Board has the final authority for approval of the Comprehensive Reliability Plan.

b. Summary of Planning Process

i. Reliability Planning

The CRPP is a long range assessment of both resource adequacy and transmission reliability of the New York bulk power system conducted over a 10-year planning horizon. It is conducted in accordance with existing reliability criteria of the NERC, NPCC and NYSRC as they may change from time to time. This process is anchored in the NYISO's market-based philosophy in which market solutions are the first choice to meet identified reliability needs. However, in the event that market-based solutions do not appear to meet a reliability need in a timely manner, the NYISO will request the appropriate Transmission Owner to proceed with a regulated backstop solution in order to ensure reliability. Under the CRPP, the NYISO has an affirmative obligation to investigate whether market failure is the reason for the lack of a market-based solution and to explore changes in its market rules if that is found to be the case.

As the first step in the CRPP, the NYISO conducts a Reliability Needs Assessment (RNA) to determine whether there are any violations of existing reliability rules with respect to either resource adequacy or transmission reliability. Following the review of the RNA by the NYISO committees and final approval by the NYISO Board, the NYISO will request solutions to its identified reliability needs from the marketplace. At the same time, the responsible TO's are obligated to prepare regulated backstop solutions for each identified need, which will serve as the benchmark to establish the time for a market-based solution to appear. Both market-based and regulated solutions are open to all resources: transmission, generation and demand response. Non-transmission owner developers also have the ability to submit proposals for regulated solutions. The NYISO has the responsibility to evaluate all proposed solutions to determine whether they will meet the identified reliability needs in a timely manner. The NYISO does not conduct an economic evaluation of the proposed solutions.

Following its evaluation of all proposed solutions, the NYISO prepares its Comprehensive Reliability Plan. The CRP will identify all proposed solutions that have been found will meet the identified reliability needs. If there is a viable market-based project that will meet the identified need in a timely manner, the CRP will so state. If there is no viable market-based proposal and the NYISO determines that a regulated backstop solution must be implemented the CRP will so state and the NYISO will request the appropriate TO to proceed with the development of its backstop solution. The NYISO also has the obligation to monitor the continued viability of proposed projects to meet identified needs and to report on its findings in subsequent Plans.

There is also a provision which will allow the NYISO Board to deal with the sudden appearance of a reliability need on an emergency basis whether during or in-between the normal CRPP cycle. In the event that there is an immediate threat to reliability, the NYISO will request the appropriate TO to develop a "gap solution" and to pursue its completion in conjunction with the NYSPSC. Such a gap solution is intended to be temporary in nature so as not to interfere with any pending market-based project.

The CRPP also address the issues of cost allocation and cost recovery. The approved Tariff contains a set of principles for cost allocation based upon the principle that beneficiaries should pay. The NYISO is presently engaged in a stakeholder process to develop the implementation procedures for cost allocation. Cost recovery for regulated transmission solutions will be through a separate rate schedule in the NYISO Tariff, while cost recovery for non-transmission solutions will be subject to the NYSPSC's procedures.

The CRPP also addresses the respective roles of the NYISO, the FERC and the NYSPSC with regard to the NYISO planning process. In the event of a dispute regarding the NYISO's findings in either the RNA or the final CRP that cannot be resolved by the normal NYISO governance procedures, the Tariff provides for disputes to be brought to either the FERC or the NYSPSC—depending upon the nature of the dispute. In the event that a Transmission Owner is unable to license or complete a regulated backstop solution that has been found necessary as a result of the CRPP, the NYISO is required to report this to FERC. Upon request, the NYSPSC will review proposed regulated solutions from either a TO or another developer prior to their submission to the NYISO.

A FERC-approved agreement between the NYISO and the New York Transmission Owners addresses the TO's rights and obligations for performance under the CRPP. This agreement also envisions the establishment of a separate rate recovery mechanism, to be approved by FERC, for the recovery of costs associated with the development and construction of a regulated transmission backstop solution required by the CRP.

ii. Economic Planning

The NYISO developed the framework for its Economic Planning Process in conjunction with its stakeholders during late 2004-early 2005. In February 2005, the NYISO Operating Committee approved this process which was included in a status report filed with FERC in March 2005. Under the approved process, the NYISO will provide enhanced information to include the posting of historic congestion costs on its website, as well as additional analysis of the potential benefits of relieving persistent constraints on the system based upon historic as well as projections of congestion costs. The NYISO's primary "metric" for congestion costs is the statewide Bid Production Cost, although other metrics, such as the accounting cost of congestion, consumer and supplier impacts are also reported. .

In contrast to other ISO/RTO economic planning procedures, the NYISO does not set a threshold for congestion, perform cost/benefit analyses or mandate solutions to such economic issues. Rather, it is intended that the enhanced information, developed through an open stakeholder process, will allow market participants and other stakeholders to assess economic opportunities and that this will result in market-based proposals. Where such market-based proposals may not be forthcoming, the NYISO will evaluate, together with its stakeholders, enhanced market-based mechanisms in order to encourage investment.

iii. Generator/Facility Interconnection Inclusive of Deliverability

The NYISO Standard Large Facility Interconnection Procedures (LFIP) and associated appendices contained in Attachment X of the NYISO Open Access Transmission Tariff (OATT) define the responsibilities and interactions of the three primary Parties involved in the interconnection process: the Developer, the NYISO, and the Transmission Owner with whose system the Developer proposes to interconnect (Connecting Transmission Owner or CTO). The LFIP defines three primary studies in the interconnection process: the Feasibility Study, the System Reliability Impact Study (SRIS), and the Facilities Study. The LFIP and pro forma study agreements require a close coordination between the NYISO and CTO in the performance of these studies, but leaves details regarding specific tasks and responsibilities to be defined in each of the “final form” study agreements. In addition, NYISO has the discretion to utilize a Transmission Owner or a consultant to perform an Interconnection Study.

The NYISO interconnection process consists of the following major elements:

- Queue Position – Priority of Interconnection Studies
- Scoping Meetings and Affected Systems
- Feasibility Studies
- System Reliability Impact Studies
- Facilities Studies

Currently, the NYISO offers only a single interconnection product or the minimum interconnection standard. That is, a generator only has to demonstrate that they can deliver energy to the grid reliably and can be securely dispatched by the NYISO congestion management system. NY does not differentiate between a generator being energy only or network resources. Network resources are required to meet deliverability criteria. The NYISO has agreed to study the adoption of the second product and file its conclusions with FERC by February 2006.

In NY, the deliverability of the aggregate of generation to the aggregate of the load to ensure resource adequacy criteria are maintained is addressed through the NYSRC resource adequacy studies. The resource adequacy studies model both transmission interface limits as well as the availability of the cable interface. This ensures that sufficient generation is available downstream of the key transmission interfaces to ensure resource adequacy criteria can be met. As result, the NY capacity market imposes locational capacity requirements on load serving entities in key load pockets. This ensures that there is a reasonable probability that there will be adequate generation available to serve the load.

iv. Point-to-Point Transmission Service Request

The NYISO offers both Firm and Non-Firm Transmission Service to Eligible Customers that reserve service for the transmission of energy from Point(s) of Receipt to Point(s) of Delivery.

From a planning perspective, requests for long-term firm transmission service are subject to System Impact Study procedures. The customer is responsible for any upgrades that the full amount of the transmission service request may dictate.

v. Stakeholder Involvement

In light of the fact that the CRRP contains both reliability and business issues, two stakeholders groups which are Transmission Planning Advisory Subcommittee ("TPAS") and the Electric System Planning Working Group (ESPWG) oversees the development of the RNA for the CRPP. This participation consist of parallel input and review stages

TPAS had primary responsibility for the reliability analyses, while the ESPWG had primary responsibility for providing commercial input and assumptions utilized in the development of reliability assessment scenarios and the reporting and analysis of historic congestion costs. Coordination will be established between these two groups and with NYISO Staff was conducted during each stage of the initial planning process.

The intention is to achieve consensus at both TPAS and the ESPWG. While no formal voting process is established at this level, which is typical for NYISO working groups, an opportunity for reporting majority and minority views will be provided in the absence of a consensus.

Following TPAS and ESPWG review, the Draft Report will be forwarded to the Operating Committee ("OC") for discussion and action and subsequently to the Management Committee for discussion and action.

c. Allocation of Responsibility - ISO vs. TO

The respective responsibilities of the NYISO and the New York Transmission Owners are described in the Attachment Y of the NYISO OATT and in a separate, FERC-approved Agreement between the NYISO and TOs which specifies the TO's rights and obligations in further detail.

The NYISO's initial responsibility under the CRPP process is to evaluate the resource adequacy and transmission reliability of the New York bulk power system in accordance with established reliability criteria of the NERC, NPCC and the NYSRC and to approve and publish the results of its assessment in the RNA. The TO's have the continuing responsibility to plan for their system and to provide such plans to the NYISO as input to the CRPP and the NYISO has the obligation to review such TO plans and to determine whether or not it is in agreement with them. When a reliability need is first identified by the NYISO, the responsible TO has assumed the obligation to provide a regulated backstop solution to the NYISO for evaluation in accordance with the timeline established for the CRPP.

The NYISO then evaluates all proposed solutions to its identified reliability needs—whether market-based or regulated solutions proposed by a TO or an alternate developer to determine whether they will, in fact, meet such needs. If the NYISO finds a deficiency in a regulated backstop proposal, it will consult with the responsible TO which will then revise its proposal accordingly. The NYISO's approved CRP will indicate those regulated backstop projects that it has determined will meet each of its identified reliability needs. When the NYISO determines that there is no market-based project that will meet an identified reliability need and that the time has come to invoke a regulated backstop, it will so state in the CRP and request the appropriate TO to begin the process of licensing and development of its regulated backstop solution. At that point, the responsible TO will file its proposal for approval by the appropriate state regulatory agency.

In the event that the NYISO determines that there is an imminent threat to the reliability of the bulk power system, either during or outside of the normal CRPP cycle, it will request the appropriate TO to propose a "Gap solution" and to consult with the NYSPSC on its implementation.

Under the NYISO OATT, as well as the separate NYISO-TO Agreement, the TO is entitled to recover all of its costs associated with development and construction of a regulated backstop solution that the NYISO determines is needed pursuant to the CRPP. Such costs will be recovered, subject to FERC approval, under a separate rate schedule of the NYISO Tariff.

d. Cost Allocation

The NYISO OATT presently contains a set of principles for the cost allocation of regulated backstop solutions to identified reliability needs that are determined to be necessary by the NYISO. These principles are based on the philosophy that beneficiaries should pay for such regulated projects. The NYISO is currently engaged in a stakeholder process to determine the specific methodology for cost allocation under these principles. It is envisioned that the NYISO will file a Tariff modification when the methodology is finalized.

e. Relation to Reliability Councils

The New York Control Area ("NYCA") power system is planned and operated to the planning and operating policies, standards, criteria, guidelines, procedures and rules promulgated by the North American Electric Reliability Council ("NERC"), Northeast Power Coordinating Council ("NPCC"), and the New York State Reliability Council ("NYSRC"). NERC establishes operating policies and planning standards for North America which includes the United States of America and the Provinces of Canada. NPCC criteria, guideline and procedures which apply to the five areas comprising NPCC (New York State, the New England States, and the Canadian Provinces of Quebec, Ontario and the Maritimes) may be more specific or more stringent than NERC standards and policies by recognizing regional characteristics or reliability needs – e.g., "the one day in ten years" loss of load expectation criteria. The NYSRC rules that apply to NYCA may be more specific or stringent than NERC and NPCC by recognizing NYCA characteristics and reliability needs – e.g., locational capacity requirements. The NYISO is the primary interface between market participants and the reliability councils.

f. Definition of Transmission

The NYISO transmission includes those transmission facilities that have been placed under the ISO's operational control and those facilities requiring ISO notification by each TO, per their specific voltage designation in the NYISO/TO agreement. This includes 230, 345, 500 & 765 kV facilities as well as some 69, 115 and 138 kV facilities, but excludes facilities classified as "local area transmission facilities"

For the purposes of the CRRP, the reliability needs assessment is only conducted for those facilities that are designated as "bulk power facilities" and which are listed in the NPCC Annual Transmission Review.

PJM

PJM is a FERC-approved Regional Transmission Organization (RTO). As such, PJM coordinates the movement of electricity over the transmission facilities of participating Transmission Owners[12] (TOs) serving all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia. As such, PJM ensures the reliability of the largest centrally dispatched control area in North America.

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of RTOs. PJM implements this function pursuant to the Regional Transmission Expansion Planning (RTEP) Protocol set forth in Schedule 6 of the PJM Operating Agreement and the interconnection request process codified under Part IV of the PJM Open Access Transmission Tariff (OATT). Both the PJM Operating Agreement and the OATT are available on PJM's web site at www.pjm.com.

a. Legal Authority

i. Statutory Authority

PJM is formed as a Limited Liability Company (LLC) under the laws of the state of Delaware to engage in such business activities as are required to carry out the terms of the PJM Operating Agreement. Specifically, the PJM RTO RTEP is subject to the FERC statutory requirements under §§ 205 and 206 of the Federal Power Act.

ii. Regulatory Authority

While PJM operates in 13 states and the District of Columbia, the PJM RTO is jurisdictionally subject to FERC regulatory authority. More specifically, FERC provides PJM with its regional transmission expansion planning (RTEP) authority through the provisions of the PJM Operating Agreement and OATT.

PJM originally consisted of eleven investor-owned utilities (PSE&G, PECO, PP&L, BGE, JCPL, MetEd, Pennelec, PEPCO, ACE, DPL and UGI), each subject to FERC's jurisdiction. PJM has now expanded to include Rockland Electric Company (RE), Allegheny Energy (AE), Commonwealth Edison Company (ComEd), Dayton Power & Light Company (Dayton), American Electric Power Company (AEP), Duquesne Light Company (DL) and Dominion. Each of the utilities is compensated by transmission customers, through PJM mechanisms, for the use of its facilities through a transmission revenue requirement ("TRR"), which consists of the costs and rate of return to which the utilities are entitled as participating transmission owners. FERC independently examines each of these jurisdictional utilities to ensure that their revenue requirements are just and reasonable.

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[12] The seventeen major TOs include Public Service Electric and Gas Company (PSE&G), PECO Energy Company (PECO), Pennsylvania Power & Light Company (PP&L), Baltimore Gas and Electric Company (BGE), Jersey Central Power & Light Company (JCPL), Metropolitan Edison Company (MetEd), Pennsylvania Electric Company (Pennelec, Potomac Electric Power Company (PEPCO), Atlantic City Electric Company (ACE), Delmarva Power & Light Company (DPL), UGI Utilities, Inc. (UGI), Rockland Electric Company (RE), Allegheny Power System (APS), Commonwealth Edison Company (ComEd), Dayton Power & Light Company (Dayton), American Electric Power Company (AEP), Duquesne Light Company (DL) and Virginia Electric Power Company (Dominion).

b. Summary of Planning Process

RTEP is PJM's process to identify transmission system upgrades and enhancements to provide for the operational, economic and reliability requirements of our customers. A region-wide planning effort in scope, the RTEP determines the best way to integrate transmission, generation and demand-side projects. RTEP applies planning and reliability criteria over a five-year horizon to identify transmission constraints and other reliability concerns. Then, RTEP looks for transmission upgrades and other projects that can mitigate constraints and reliability problems, examining their feasibility, impact and costs. In 2006, PJM will expand the planning horizon for its RTEP from five years to 15 years into the future. Extending the planning horizon allows better planning both for reliability improvements and for upgrades that make sure the electric grid best supports economic sales of power around the PJM region.

Fundamentally, PJM's FERC-approved Regional Transmission Expansion Planning Process ("RTEP Process") is based on a foundation of bulk power system reliability to ensure PJM's ongoing ability to meet control area load-serving obligations. The RTEP Process is driven by a number of factors, including the following:

- NERC Regional Reliability Assessments
- PJM Transmission Adequacy Assessment
- PJM Annual Report on Operations
- PJM Load Serving entity (LSE) capacity plans
- Generator and Transmission Interconnection Requests
- Transmission Owner transmission development plans
- Interregional transmission development plans
- Firm Transmission Service Requests
- Requests for Generator retirements
- Notifications of Demand Response participation
- PJM Transmission Expansion Advisory Committee (TEAC) input
- PJM Development of Economic Transmission Enhancements

PJM analyzes the cumulative effect of these drivers through the RTEP Process. The outcome of this process is a single plan that recommends specific transmission facility enhancements and expansion on a reliable and environmentally sensitive basis and in full consideration of available economic congestion mitigation alternatives. These analyses are conducted on a continual basis, reflecting specific new customer needs as they are introduced, but also readjusting as needs change. In this way, the plan continually represents a reliable means to meet PJM power system requirements in a fully integrated fashion, at the same time preserving the rights of all parties with respect to the transmission system.

i. Reliability Planning

In order to establish a starting point for development of Regional Transmission Expansion Plans and determine cost responsibility for expansion facilities beyond those required for system reliability, a 'baseline' analysis of system adequacy and security is necessary. The purpose of this analysis is threefold:

1. To identify areas where the system, as planned, is not in compliance with applicable NERC and regional reliability council standards, Nuclear Plant

Licensee requirements and PJM reliability standards. The baseline system is analyzed using the same criteria and analysis methods that are used for assessing the impact of proposed new projects. This ensures that the need for system enhancements due to baseline system requirements and those enhancements due to new projects are determined in a consistent and equitable manner.

2. To develop and recommend facility enhancement plans, including cost estimates and estimated in-service dates, to bring those areas into compliance.
3. To establish what will be included as i) baseline costs for system reliability and ii) expansion costs for facilities beyond those required for system reliability in the allocation of the costs of expansion for those projects proposing to connect to the PJM System.

PJM has authority to mandate system upgrades required for reliability deficiencies. PJM also has authority to require an upgrade or expansion of TO facilities to meet regulatory obligations.

Transmission system reinforcements needed to maintain national and regional reliability standards are built by transmission owners and paid for by customers in proportion to benefit. Transmission owners recover their costs through FERC-approved transmission service rates.

Generation and transmission project developers are responsible for costs associated with interconnecting their facilities to the grid. Interconnection of such facilities also may require the upgrading of additional system elements to maintain reliability; if so, an appropriate proportion of those costs are borne by the project developer.

In addition, PJM's RTEP Process is coordinated with the rest of the eastern interconnection through coordinated planning arrangements with the MISO, NYISO, NE-ISO and TVA in order to ensure the reliability of interconnected system operation and markets.

ii. Economic Planning

Through spot market energy prices and the RTEP, PJM market participants can identify the portions of the transmission grid prone to persistent congestion, the costs of which customers are not able to fully hedge through financial transmission rights. PJM's economic planning process analyzes all congestion on the PJM Transmission System on an ongoing basis to identify opportunities for economic transmission solutions to relieve unhedgeable congestion costs. PJM will not implement economic solutions unless market forces fail to resolve such unhedgeable congestion.

Market participants proposing solutions to resolve such constraints are responsible for direct interconnection costs and for an appropriate proportion of any network upgrade costs required to facilitate their interconnection. In return, they receive the Auction Revenue Rights (ARRs) associated with the additional transmission capability their upgrade yields. These ARRs entitle the holder to the revenues from the auction for Financial Transmission Rights (FTRs) that parties may acquire for use to hedge against congestion costs.

iii. Generator/Facility Interconnection Inclusive of Deliverability

The process to request new Generator/ Facility interconnections is described under Part IV of the PJM Open Access Tariff (OATT). The interconnection process includes an initial application to PJM to enter into a project queue as well as steps to successfully complete a Feasibility Study, a System Impact Study and a Facility Study prior to execution of an Interconnection Service Agreement.

Deliverability is an essential element of PJM's resource adequacy requirements included in the PJM RTEP Process. Deliverability ensures, only, that the aggregate of capacity resources can be utilized to deliver energy to the aggregate of load. Capacity Resources must be deliverable, consistent with the loss of load expectation, to the total system load, including portion(s) of the system in the PJM Control Area that may have a capacity deficiency at any time. Certification of deliverability means that the physical capability of the transmission network has been tested and found to provide service consistent with the assessment of available transfer capability as set forth in the PJM Tariff and, for Capacity Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained or provided for Network Transmission Service or Firm Point-To-Point Transmission Service to have capacity delivered on a firm basis under specified terms and conditions.

PJM's deliverability criteria consists of two assessments - the Deliverability to Load and the Deliverability of Generation to the aggregate of load. Deliverability to Load ensures that, within accepted probabilities, energy will be able to be delivered to applicable PJM regional load, regardless of cost, from the aggregate of capacity resources available to PJM. Deliverability of Generation ensures that, under normal transmission system conditions, if capacity resources are available and called on, their ability to provide energy to the system at peak load will not be limited by the dispatch of other certified capacity resources.

iv. Point-to-Point Transmission Service Request

PJM offers both Firm and Non-Firm Transmission Service to Eligible Customers that reserve service for the transmission of capacity and/or energy from Point(s) of Receipt to Point(s) of Delivery.

The minimum term of Long Term Firm Point-To-Point Transmission Service is one year and the maximum term is specified in a Service Agreement. The term of Short-Term Firm Point-To-Point transmission Service is one day, one week, or one month.

Non-Firm Point-To-Point Transmission service is available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point –To-Point Transmission Service is entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies may be greater than one month.

From a planning perspective, requests for long-term firm transmission service are subject to System Impact Study procedures. The customer is responsible for any upgrades that the full amount of the transmission service request may dictate.

v. Stakeholder Involvement

Stakeholders are involved in a coordinated planning process and review to ensure needs identified by various market participants can be addressed through system upgrades, system expansion, including interconnection of new generation and through demand side programs, where appropriate. The States and other stakeholders participate in all processes to provide guidance and recommendations on process objectives and to assure continuity of information and collaboration across all forums.

PJM's RTEP process is collaborative. Forums and processes provide opportunities for stakeholders to help PJM improve the grid, ensuring reliability and access to robust, competitive markets. PJM's Transmission Expansion Advisory Committee (TEAC) activities provide the primary forum for the ongoing exchange of ideas, discussion of issues and presentation of planning process results. PJM governing committees such as the PJM Members Committee, Planning Committee and Transmission Owners

Agreement Administrative Committee provides additional opportunity for stakeholders to provide process input. PJM ad hoc stakeholder groups are periodically commissioned to address specific issues. Recent groups have addressed such issues as economic planning processes and FERC interconnection rulemakings. Jurisdictional liaisons foster two-way communication and resolution of planning issues with legislative and regulatory bodies.

c. Allocation of Responsibility - RTO vs. TO

PJM is responsible for the reliable operation and security of facilities under its control. The member TOs have the statutory and regulatory obligations to plan and maintain a reliable system to serve their customers. They have agreed under the terms of the PJM Transmission Owners Agreement to transfer that planning responsibility to PJM. PJM works closely with FERC, the various state PUCs and other stakeholders throughout the RTEP Process. The TOs develop system expansion plans to meet their area needs and also perform system impact assessments of potential interconnections to their systems. PJM reviews and approves the technical and operational feasibility of all expansion plans based on the applicable NERC and MAAC, ECAR, MAIN and SERC planning standards and criteria.

d. Cost Allocation

Cost allocation for transmission system expansion under PJM's "Regional Transmission Expansion Planning Protocol" is described in the PJM Operating Agreement, Schedule 6, Articles 1.5.6 (f) and 1.5.6 (g). Basically, the cost is allocated to those Market Participants that contribute to the need for and derive benefits from the pertinent enhancement or expansion. The PJM Operating Agreement may be accessed from the PJM web site at: http://www.pjm.com/documents/downloads/agreements/oa.pdf

Developers are responsible for all costs of direct interconnection of their facilities to the power system. The developer funds network system upgrades or expansion required to interconnect a developer's project.

Cost allocation for transmission system expansion required for new generator and/or transmission facility interconnections is described in PJM Manual 14B, Attachment B. Cost allocation is based on the proportion that the Customer/Developer project impacts on the need for the expansion. PJM Manual 14B may be accessed from the PJM web site at: http://www.pjm.com/contributions/pjm-manuals/pdf/m14bv04.pdf

Subsequently, the various rights to which a customer may be entitled – ATC Revenue rights, ARRs, etc. – are based on this cost proportion responsibility for upgrades.

e. Relation to Reliability Councils

PJM and the affected TOs are voluntary participating members in the appropriate Electricity Reliability Coordinating Councils - MAAC, ECAR, MAIN and SERC – as well as the broader governing activities of the NERC itself. PJM's FERC-approved RTEP Process is based on a foundation of bulk power system reliability that ensures PJM's ongoing ability to meet control area load-serving obligations. The RTEP Process is driven by a number of inputs and drivers, including NERC Regional Reliability Assessments, per the planning criteria and guidelines of MAAC, ECAR, MAIN and SERC.

f. Definition of Transmission

PJM "transmission includes those transmission facilities that have been placed under the RTO's operational control by each TO, per their specific voltage designation in their respective schedule of the OATT. These include 230, 345, 500 & 765 kV facilities as well as some 34, 69, 115 and 138 kV facilities for certain TOs, but excludes directly assignable radial lines and associated facilities interconnecting generation, lines and associated facilities classified as "local distribution" facilities or other facilities excluded consistent with FERC established criteria for determining facilities subject to RTO operational control.

PJM may require that certain conditions be met or upgrades be completed before accepting control over any transmission lines, facilities or entitlements that are located in a Control Area outside of the PJM Region, are operated under the direction of another Control Area or independent system operator, and cannot be integrated into the RTO Controlled Grid due to technical considerations.

SPP

The SPP is a FERC-approved Regional Transmission Organization (RTO). Organized as a not-for-profit corporation, SPP coordinates the movement of electricity over the transmission facilities of participating Transmission Owners (TOs) serving all or parts of 8 states (Arkansas, Kansas, Louisiana, Mississippi, Missouri, Oklahoma, New Mexico, and Texas).

Southwest Power Pool, Inc. has served as a reliability council of the North American Electric Reliability Council (NERC) since its founding in 1968, and was designated a regional transmission organization (RTO) by the Federal Energy Regulatory Commission (FERC) in October 2004. Since 1997, SPP has provided independent security coordination and tariff administration, pursuant to a FERC- approved tariff, across its service area with over 33,000 miles of transmission lines and a gross plant investment approaching $4 billion. SPP is a group of 45 electric utilities serving more than 4 million customers across all or parts of eight southwestern states in the Eastern Interconnection.

a. Legal Authority

i. Statutory Authority

SPP is a not-for-profit Company working under the laws of the state of Arkansas and as such is subject to the FERC statutory requirements under §§ 205 and 206 of the Federal Power Act.

ii. Regulatory Authority

The SPP is subject for FERC's regulatory authority and FERC provides the SPP with its grid planning authority.

b. Summary of Planning Process

As an RTO, SPP is responsible for collaborative intra-regional, cooperative inter-regional planning and implementation of effective, coordinated transmission expansions. The SPP planning process shall enable SPP to provide efficient, reliable, and competitive generation market Transmission Services on a non-discriminatory basis taking into account the requirements of all Stakeholders while coordinating with applicable Federal, State and Local Regulatory Authorities.

Objective of SPP Plan

SPP will meet the planning and expansion objectives of FERC Order 2000 through a coordinated plan involving an open stakeholder process. The SPP RTO Expansion Plan (SREP) will be created to promote the efficient expansion of the transmission system under the control of SPP and enable competitive generation markets. By coordinating the planning throughout the SPP system, the SREP will maintain or improve existing reliability levels, while minimizing overall costs of the plan. Coordination of plans over a large regional area, with input from stakeholders, will ensure the plans developed provide the best overall solutions to reliability needs with appropriate consideration of economic and environmental factors.

The plan will identify potential expansion projects that are needed to meet reliability standards, and to interconnect new generation, with consideration for load growth, competitive generation market, stakeholder input, and transmission service commitments. In addition, the plan will consider potential plans that could be developed to address transmission congestion. It will also consider benefits associated with development of new generation at specific locations on the system as alternatives to transmission expansion.

SPP has been involved in regional planning for decades. SPP did not wait for RTO designation to formalize a more comprehensive, open and transparent, planning process to address transmission expansion needs within the SPP footprint. The SPP OATT contains procedures in Attachment O that describe the coordinated planning process. The Transmission Working Group (TWG) has been assigned primary responsibility for the regional planning process. The TWG consists of both Transmission Owners and Non-Transmission Customers. Meetings are open and agendas posted on the SPP web site. SPP stakeholders are encouraged to actively participate in the regional planning process to ensure that the recommended expansion plans are the best solutions for the footprint.

SPP, as a regional reliability council, has coordinated planning for many years. SPP staff has historically performed regional assessments of the transmission system and coordinated studies of the SPP transmission owners. This process was included in the Tariff upon the addition of long-term transmission service on April 1, 1999.

SPP has performed or participated in many recent regional expansion studies. During 2000, SPP began a Bulk EHV Transmission Study. This study identified potential upgrades to relieve known constraints in the SPP. This study was completed in two phases during 2001. SPP then followed up that study by participating in the Midwest ISO Transmission Expansion Plan (MTEP) during 2002 and 2003. Up until the MISO-SPP merger termination in early 2003, SPP staff and resources in Little Rock provided leadership and significant support to the MTEP-03 effort. The initial MISO study was completed in June of 2003 with SPP being a sub region. SPP continues to support model building efforts and inter-regional studies with neighboring NERC regions and other entities responsible for the planning and operations of the bulk electric transmission system.

It is important to note that SPP's planning process has been effective in planning and expanding the transmission system in the past several years. SPP as maintained reliable transmission system during this period through active review and engineering assessment. SPP has upgraded approximately 75 transmission facilities through the regional Tariff. A prime example of the effectiveness was SPP's ability to upgrade the LaCygne-Stilwell 345kV line. This line was identified as one of the key constraints in the Eastern Interconnection in the FERC 2001: Electric Transmission Constraint Study, Division of Market Development. It was the only SPP facility identified as a limit in the study. SPP Transmission Owners, through the regional planning process, reached agreement on benefit and cost support to upgrade this key limitation [Docket ER03-547-000]. An innovative transmission upgrade approach was used and construction was completed ahead of schedule, providing for increased SPP reliability and transmission system capacity in 2003. This key upgrade would not have occurred without a functioning regional planning process.

As an approved RTO, SPP will be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and coordinate such efforts with appropriate state authorities.

SPP has been proactive in its transmission expansion planning efforts which continue to evolve with time. In November 2003, SPP formally kicked off its Regional Planning process. The summit materials and related documents are available on our planning webpage. SPP through the TWG has designed a process for planning and expansion that encourages open participation for market-motivated solutions to relieve congestion. SPP staff is responsible for development of the SPP Plan. SPP has been working with state regulatory agencies and legislators to ensure that the regional planning process addresses their needs. With time, the Regional State Committee (RSC) and its working groups are becoming more involved in the transmission expansion planning process at SPP. SPP planning and expansion process will be coordinated and integrated with programs of existing Regional Transmission Groups. SPP has a history of coordination with existing Regional Transmission Groups through its efforts on coordination agreements and information exchange, and it will continue these activities as an RTO. This coordination is demonstrated by SPP's past and continuing participation with the Midwest ISO in their Transmission Expansion Plan and the SERC members with their VS.TE model building efforts. The SPP regional transmission plan will include all transmission facility expansion in the region and attempt to assess the combined effect on loop flows and reliability of all existing and planned facilities.

In early 2004, SPP initiated a special study of transmission expansion plans for the Panhandle/Kansas sub-region of SPP. SPP staff is in the process of evaluating the benefits of several EHV transmission expansion projects to improve imports/exports for this sub-region which has significant potential to provide demand and energy from wind farm developments. SPP is expanding its capabilities with the recent installation/training of PowerWorld and Henwood's MarketSYM tools for evaluating the market and commercial benefits of system expansion alternatives.

As noted above, much has happened recently regarding planning at SPP. In fact the FERC in their initial Order regarding SPP's RTO filing was very supportive of these planning efforts. The FERC order in paragraph 185 states:

> ***We commend SPP for its efforts in updating its transmission planning and expansion process. SPP is currently reviewing this function with an eye toward making the process more open and participatory and is evaluating a two-year planning cycle with the first year's focus on reliability and the second year's focus on market needs. The current draft of this cycle calls for approval of the transmission plan on September of the second year. We believe SPP's efforts here are a critical fist step toward a regional assessment of transmission needs and strongly support its proactive efforts.***

The transmission expansion planning process will continue to evolve as SPP moves forward as an RTO. SPP has created a dedicated webpage at http://www.spp.org/Objects/Engineer.cfm to post numerous public documents regarding SPP’s expansion planning process and results. All stakeholders are encouraged to fill out a stakeholder ID form and sign a confidentiality agreement and return it to SPP to obtain access to the regional planning models and project data which are posted on a secure eRoom site.

SPP management has stated that a key objective as an RTO will be focusing on transmission expansion opportunities.

Model Development

SPP has long been involved in the development and coordination of large scale power models with neighboring regions as part of the NERC MMWG effort. SPP members rely on SPP staff to coordinate and create power flow, short circuit and stability models for use by SPP and its members for analyses. SPP is installing the ODMS/Models On Demand (MOD) package from PTI to improve the efficiency and effectiveness of the model building and maintenance processes needed to support the various applications by SPP and its members.

SPP is working with others, e.g., PJM, to improve the functionality and capabilities of MOD. MOD will help create and organize models, as well as the several levels of model data for SPP members. SPP continues to work with the NERC MMWG to improve the MDWG model building effort to collect and maintain additional modeling data and details based on consistent definitions in a common format to benefit all model users. SPP is in the process of improving and expanding the data collection, project tracking, model building and maintenance efforts associated with the SPP MDWG. Significant progress has been made recently in the coordinated model building and analysis with neighboring regions. The

The SPP MDWG manual is available at http://www.spp.org/Publications/MDWG_PowerFlow_Manual_05.pdf.

i. Reliability Planning

SPP is responsible for planning and arranging for all the SPP Plan transmission expansion facilities through an open planning process. SPP Staff is responsible for annually updating the transmission expansion plan. SPP Staff is responsible for developing a Study Plan and arranging for Stakeholder meeting(s) as necessary for collaborative input and refinement of the planning scope, project definition and purpose, work assignments and responsibility, scheduling, cost analysis, alternatives, and assumptions.

SPP Staff is responsible for incorporating the input from neighboring entities responsible for bulk power expansion planning. Projects affecting regional reliability and competitive generation markets will be integrated into the SPP Plan. SPP Staff is responsible for including all TO transmission expansion plans in the SPP Plan. SPP Staff will collaboratively create and develop the processes, procedures and protocols associated with an effective and efficient model building effort. With the help of the TWG, SPP Staff is responsible for directing the ensuing collaborative study and assessments.

SPP Staff is responsible for directing the preparation of a preliminary report proposing new projects, modifications to existing projects and proposing alternative solutions to deficiencies identified in the assessment process. Since the planning process is an open iterative collaborative process, preliminary results may be reviewed in open meetings to obtain collaborative agreement on proposed changes in the plan before proceeding. At this point or earlier, in parallel if inter-regional problems are already known, SPP staff will work with neighboring entitles responsible for transmission planning and operation to cooperatively combine the expansion plans and to assess and consolidate the needed Intra-Regional Facilities.

Objective of SPP Plan

SPP will meet the planning and expansion objectives of FERC Order 2000 through coordinated planning involving an open stakeholder process. The SPP Transmission Expansion Plan (SPP Plan) will be created to promote the efficient expansion of the transmission system under the control of SPP and enable competitive generation markets. By coordinating the planning throughout the SPP system and cooperative Inter-RTO planning, the SPP Plan will maintain or improve existing reliability levels, while minimizing overall costs of the plan. Coordination of plans over a large regional area, with input from stakeholders, will ensure the plans developed provide the best overall solutions to reliability needs with appropriate consideration of economic and environmental factors.

The plan will identify potential expansion projects that are needed to meet reliability standards, and to interconnect new generation, with consideration for load growth, competitive generation market, stakeholder input, and transmission service commitments. In addition, the plan will consider potential plans that could be developed to address transmission congestion. It will also consider benefits associated with development of new generation at specific locations on the system as alternatives to transmission expansion.

SPP Plan Implementation

Any transmission plan is subject to change, as system conditions change. Changes in load growth, changes in usage patterns, development of new generation interconnections, changes in projected service dates of interconnection plans, delays in regulatory approvals of transmission projects, or ongoing development of preferred plans, all may cause changes to the overall SPP Plan. These changes, as they become known to the transmission Owner, will need to be communicated to SPP, so that their impact on the overall plan can be evaluated.

Annual Plan Review and Update

The SPP will revise the plan on an ongoing basis to reflect changing system conditions. Changes will be made public by the SPP through annual plan updates, or sooner, if changes result in major changes to the overall plan. The annual update will reflect changes that may have occurred, the reasons for the changes, their impacts, including any new plans that may be proposed to address the current projections.

Planning Data

In order to perform its planning responsibility, the SPP will need transmission system data and information from the Transmission Owners, and generation owners. This information will need to be updated on a regular basis. Basic planning information that will be needed from Transmission Owners to perform reliability assessments includes

1. Transmission Owner specific Planning criteria
2. Load forecasts with the specificity needed for firm and interruptible loads
3. Operating guides or procedures including special operating rules or protection systems
4. Equipment (Major components such as lines and transformers, sub components such as breakers, switches etc.) data and ratings
5. Machine models, data and ratings for existing units.

In addition, in order to develop potential expansion plans that will coordinate with existing facilities and future plans of the Transmission Owners, additional system information will be required, including:

1. Maps (Overview, topological, etc.)
2. System and/or switching One-line diagrams as needed
3. ROW availability
4. Line construction and utilization (line data sheets and calculated quantities such as EMF, sequence impedances, age, etc)
5. Station ultimate development diagrams

ii. Economic Planning

In 2003, SPP initiated a two year planning process which will focus initially on the reliability needs of the system and then on the commercial and market needs for all the stakeholders in the footprint. This process was developed by SPP staff in conjunction with the Transmission Working Group. Details regarding key assumptions, models, project data, specific tasks, outstanding issues, progress reports, maps and study results are available on the SPP website. The process has evolved evolve over time to integrate tariff study results and provide project recommendations in a timely manner to better fit into the construction budget cycles of members. Although annual reports will be provided with recommendations regarding transmission expansion projects within the footprint, SPP staff has a goal of reducing the overall planning cycle process to a one year duration. A one year cycle has been proposed for the 2006 reliability assessment.

iii. Generator/Facility Interconnection Inclusive of Deliverability

Generation Owners

Generator Owners are responsible for providing modeling data used by the SPP and Transmission Owners for load flow, short circuit, dynamic stability and other future studies as needs arise. Generators are responsible for meeting regulatory reliability standards and planning reliability clauses in their TO and SPP Agreements as applicable. Generator Owners are encouraged to participate in the planning process through the stakeholder input and review phases of the planning process.

Load Serving Entities

Load Serving Entities will be responsible for annually making and providing SPP with timely accurate forecasts of Network Load. Load Serving Entities may further involve themselves in the SPP planning process by participating in the stakeholder input and review phases of the planning process.

Transmission Customers

Transmission Customers will have the same planning responsibilities as Load Serving Entities.

iv. Point-to-Point Transmission Service Request

SPP offers both Firm and Non-Firm Transmission Service to Eligible Customers that reserve service for the transmission of capacity and/or energy from Point(s) of Receipt to Point(s) of Delivery.

The minimum term of Long Term Firm Point-To-Point Transmission Service is one year and the maximum term is specified in a Service Agreement. The term of Short-Term Firm Point-To-Point transmission Service is one day, one week, or one month.

Non-Firm Point-To-Point Transmission service is available for periods ranging from one (1) hour to one (1) month. From a planning perspective, requests for long-term firm transmission service are subject to System Impact Study procedures. The customer is responsible for any upgrades that the full amount of the transmission service request may dictate.

v. Stakeholder Involvement

Stakeholders are involved in a coordinated planning process and review to ensure needs identified by various market participants can be addressed through system upgrades, system expansion, including interconnection of new generation and through demand side programs, where appropriate. The States and other stakeholders participate in all processes to provide guidance and recommendations on process objectives and to assure continuity of information and collaboration across all forums.

Planning within SPP is to be a collaborative process with Transmission Owners, users and other interested parties. This process requires that Transmission Owners continue to develop expansion plans to meet the needs of their systems. At the same time, SPP planning staff will assess the SPP system for its ability to meet applicable reliability standards and to meet the needs of the competitive generation market and stakeholder concerns including regulatory authorities. This “bottoms-up, top down approach” will be advantageous to all stakeholders. The Transmission Owners will develop their system specific plans, which will then be consolidated by the SPP Planning Staff to develop an overall integrated SPP Transmission Expansion Plan. This process will allow for all projects with regional and inter-regional impact to be analyzed for their combined effects. It will allow modifications and alternatives to proposed plans to be developed and explored, that may provide more effective or economical solutions to regional needs, while still meeting local needs. SPP will develop and adopt a transmission plan that takes into consideration the transmission needs of all stakeholders.

c. Allocation of Responsibility – RTO vs. TO

SPP will develop the overall regional and inter-regional plan by incorporating, and modifying if appropriate, plans generated from multiple sources, including

- Ongoing Planning by Transmission Owners and regional planning groups
- Plans developed through studies associated with requests for firm transmission service
- Plans developed through studies associated with requests for interconnection of generators
- Plans developed by SPP Staff to meet intra-regional needs
- Plans developed with other RTOs to meet inter-regional needs

The Transmission Owners will be responsible for preparing and updating their detailed power system models for use as needed by themselves, Regional and sub regional Planning Groups, SPP and other RTOs or Third Parties to perform the required Interconnection and expansion Studies.

The Transmission Owners are responsible for developing their specific expansion projects. The TOs projects will be integrated into the development of the SPP Expansion Plan. SPP staff is proposing to include 69kV reliability projects in its second Regional Planning cycle to ensure that the SPP Plan is comprehensive. TOs will be responsible for identifying 69kV system improvement projects required to meet reliability standards, but the SPP Staff will review and approve those projects before they are included in the SPP Plan.

TOs are responsible for applying their expert knowledge of the strengths and weakness of their respective transmission systems to the evaluation of all projects in the SPP Expansion Plan affecting their respective transmission systems. TOs are responsible for participating in SPP initiatives to assist in expansion studies and alternatives. Another fundamental responsibility of the TOs is to provide timely accurate estimates of needed facilities so realistic evaluations of alternatives are possible.

Finally, Transmission Owners are responsible for the expeditious implementation including land acquisition, regulatory permitting and construction of the SPP Board certified SPP expansion projects.

Stakeholders, including representatives of the Regional State Committee (RSC), will be able to provide SPP with critical stakeholder input and review of transmission expansion projects in the SPP Plan as they are developed and updated. The RSC inputs will assist SPP in the development of realistic transmission expansion projects and alternatives to meet the needs of their citizens as well as neighboring regions. Since all SPP planning meetings are open to all stakeholders, stakeholders are responsible for attending as non-member participants as their interest dictates. It is envisioned that forums such as WebEx, e-mail, e-rooms and other correspondence and open discussion periods will allow non-members to effectively participate in the SPP planning process.

d. Cost Allocation

Effective May 5, 2005, SPP implemented a regional transmission cost allocation plan with regard to new transmission upgrades. The plan benefits customers by establishing cost allocation and cost recovery methods for the SPP regional transmission organization (RTO) expansion process, thereby supporting needed and efficient transmission investment and expanding wholesale power markets.

e. Relation to Reliability Councils

In developing expansion plans for the SPP system, SPP Staff will comply with the NERC (or successor) Planning Standards, the criteria and guides of the Regions and subregions, and the specific planning criteria of the member Transmission Owners filed with FERC, to the extent that doing so does not introduce conflicts in the application of these various standards.

f. Definition of Transmission

After significant debate, SPP Transmission Definition Task Force approved Attachment AI to the SPP OATT which includes facility inclusion/exclusion criteria, as well as a schedule for implementation. Facility inclusion criteria is as follows; 1) all non-radial power lines, substations, and associated facilities, operated at 60 kV or above, plus all radial lines operated at or above 60 kV, and associated facilities, that serve two or more eligible customers not Affiliates of each other. 2) all facilities that are utilized for interconnecting the various internal zones to each other as well as those facilities that interconnect SPP with other surrounding entities, 3) control equipment and facilities necessary to control and protect facilities qualifying as Transmission Facilities, 4) for substations connected to power lines qualifying as Transmission facilities, where power is transformed from a voltage higher than 60 kV to a voltage lower than 60 kV, facilities on the high voltage side of the transformer will be included with the exception of transformer isolation equipment, 5) the portion of the direct-current interconnections with areas outside of the SPP region (DC ties) that are owned by a Transmission Owner in the SPP region, including those portions of the DC tie that operate at a voltage lower than 60 kV, 6) all facilities operated below 60 kV that have been determined to be transmission pursuant to the seven (7) factor test set forth in FERC Order No. 888, 61 Fed Reg. 21,540, 21,620 (1996), or any applicable successor test and 7) any facility determined by the Transmission Provider to be a Base Plan Upgrade, pursuant to Section III of Attachment J to the Tariff.

Facilities exclusion criteria is as follows: 1) generator step-up transformers and generator leads, 2) radial lines from a generating station to a single substation or switching station on the Transmission System; and Direct Assignment Facilities.

Implementation of the new transmission definition will be within three years after FERC acceptance of these Tariff modifications. TOs will file for determination of which facilities are Transmission (Seven Factor Test), and file to adjust Transmission rates

ISO/RTO REPORT II: EXPANSION PLANS

AESO

a. Summary of Most Recent Plans

Summaries of the AESO's most recent plans can be found in its 10-Year Transmission System Plan [2005 – 2014], published in December, 2004 and its 20-Year Transmission System Outlook [2005 – 2024], published in June, 2005. These reports can be found on the AESO's website at www.aeso.ca.b.

b. Planning Issues

Significant planning issues currently facing the AESO include:

Regional Planning Issues

There are a number of area-specific issues impacting transmission planning in the various regions of Alberta. The following provides several examples:

- The very large amount of wind-powered generation being proposed for interconnection to the southwest and southeast portions of the system will require a very extensive strengthening of the 240 kV system in this area.
- The northwest portion of the system has historically relied on the use of Transmission Must Run ("TMR") generation in order to maintain system reliability. Extensive use of TMR is felt by some to run counter to the competitive energy market and the AESO is currently developing a transmission expansion plan that would essentially eliminate the need for TMR in the region.
- In the northeast portion of the system the Fort McMurray area encompasses crude oil reserves in quantities second only to those found in Saudi Arabia. However, these reserves are in the form of oil sands that require extensive refining and upgrading to order to produce a usable product. This refining and upgrading results in a requirement for large amounts of steam to be produced that in turn provides an opportunity for the development of significant co-generation facilities. However, depending on a large number of project and site-specific variables the amount of co-generation that will be developed varies widely and could result in the area being either a significant load point on the system or having significant amounts of surplus generation available to the rest of the system.

Project Cost Escalation

Over the past twelve to eighteen month period the electric utility industry in Alberta has experienced very significant and rapid cost escalation. Both material and labor costs have increased rapidly; in some cases material costs have been escalating by about 1% per month. Clearly this kind of escalation concerns many of the AESO's stakeholders and the AESO has been working with them and the Transmission Facility Owners to ensure that all costs are appropriate and that cost-effective transmission solutions are implemented.

Regulatory Process

With the creation of the AESO in 2003 a new regulatory process for the approval of transmission projects was also introduced. The new process requires the AESO to file an application with the Alberta Energy and Utilities Board ("EUB") for approval of the need for the new transmission facilities. After the AESO receives approval it then arranges for the facilities to be build by the appropriate Transmission Facility Owner, who is then required to file an application with the EUB for approval of the specific line route. This two-stage process has resulted in additional regulatory lead time and complexity being introduced into the approval process. The AESO has been working with its stakeholders, including the EUB, to find ways to streamline the process.

Planning Resources

The AESO has found it difficult to find sufficient numbers of experienced transmission system planners. During the 1990's the electric industry in Alberta, as in much of North America, experienced a decline in the numbers of transmission planners being developed. This gap in the "experience chain" is now manifesting itself in a shortage of transmission planners in the ten to fifteen year range of experience. The AESO will continue to recruit locally, nationally and internationally to fill its manpower resource needs.

c. Statistics

i. Load Growth

(Year-end 2004)

System peak load – 9,438 MW

Annual electric energy consumption – 54,972 GWh

Installed generation capacity – 12,006 MW

No. of generating units – approximately 167

No. of transmission substations – approximately 519

Length of transmission lines – approximately 21,134 kilometers (13,132 miles)
Transmission voltage levels – 500, 240, 138/144 and 69/72 kV

Control area size – 660,000 sq. kilometers (255,000 sq. miles)

ii. Interconnection Queue

The AESO does not have a formal generation interconnection queue. Currently the AESO is working with generation developers representing the potential addition of approximately 1500 MW of coal-fired, 350 MW of gas-fired and 2250 MW of wind generation in the next five to ten year time period.

iii. Transmission Build

The following figure provides a non-geographic overview of the main 500 kV and 240 kV transmission systems in Alberta. Since its creation in 2003 the AESO has received regulatory approval for approximately 80 transmission projects, which will result in the addition of approximately 330 kilometers (200 miles) of new 500 kV, 580 kilometers (350 miles) of new 240 kV and 200 kilometers (120 miles) of new 138/144 kV transmission line.

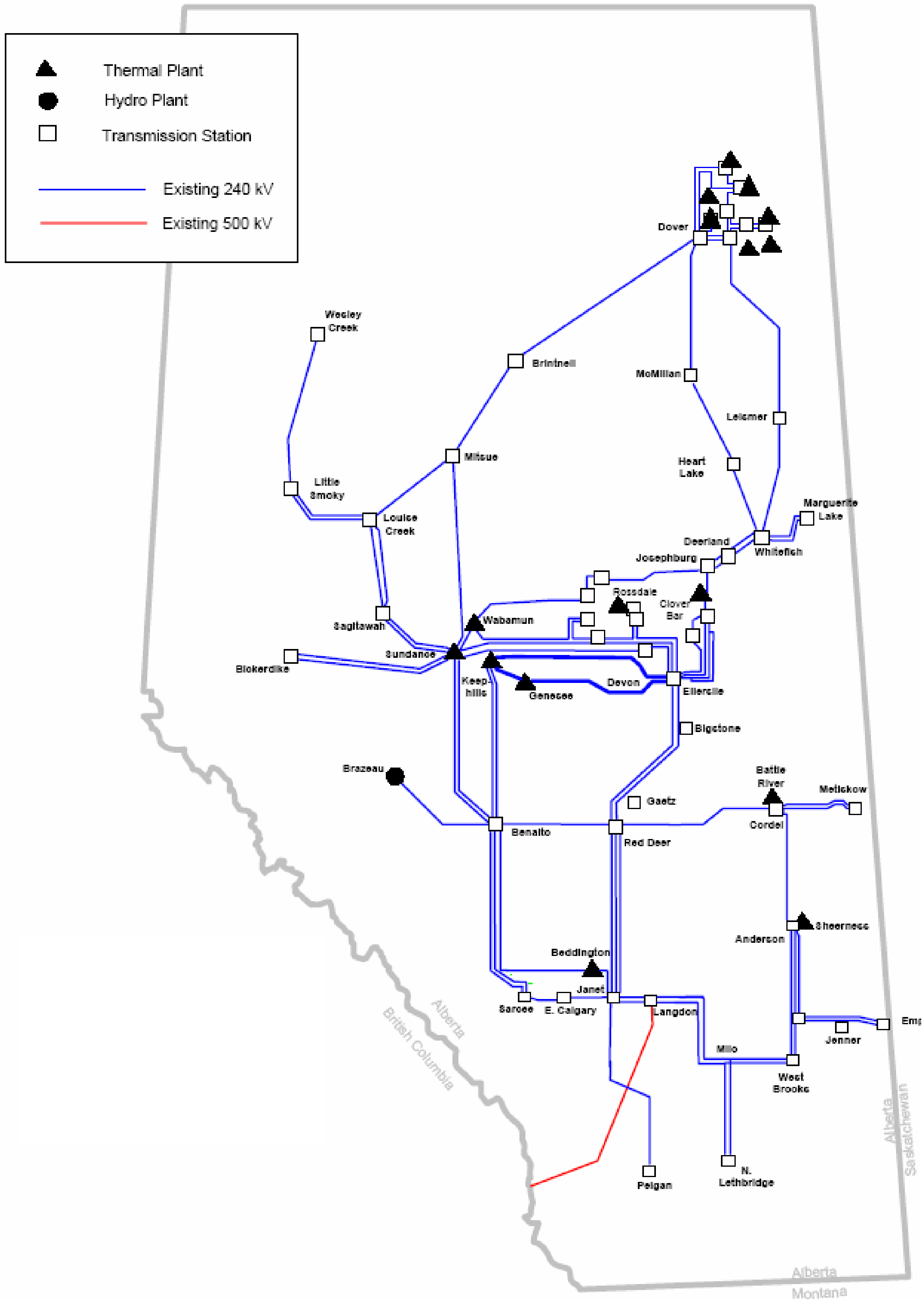

Figure 1: Bulk System 2005 Existing

iv. Resource Adequacy

As a result of industry deregulation in Alberta in 1996 no entity had the formal responsibility for resource adequacy. Recently however the Alberta Department of Energy released a policy paper[13] that requires the AESO to institute a number of market-design enhancements to ensure both short-term and long-term adequacy of supply. The details of these enhancements are currently being developed by the AESO in consultation with the Department and stakeholders.

[13] Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable, June 6, 2005, Alberta Department of Energy

CA-ISO

a. Summary of Most Recent Plans

The California ISO (CAISO) and its Participating Transmission Owners (PTOs), produce an annual transmission expansion plan of the CAISO-controlled grid. Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) each develop their respective transmission expansion plan covering a ten-year planning horizon for its service area. These plans are completed in open stakeholder processes involving the PTOs, CAISO, and Market Participants. Meetings attended by interested stakeholders occur at opportune times in the assessment schedule of each PTO. Also, the CAISO reviews and provides comments on each of the assessments to ensure that the PTOs have adequately analyzed their systems against the CAISO Grid Planning Criteria, the proposed projects effectively mitigate the identified problems, all reasonable alternatives have been considered, and the most economic solution is being pursued. All projects are evaluated and considered for approval by CAISO staff. The CAISO Board approves projects having capital costs of $20 million or more.

In addition, since each PTO focuses solely on its portion of the CAISO-controlled grid, CAISO staff assesses the composite California grid to identify potential reliability needs across the bulk power 230 kV and 500 kV system.

The following is a summary of the most recent annual transmission expansion plan for the CAISO-controlled grid

Southern California Area

Southern California Edison Company developed a 2004 Annual Ten-Year Expansion Plan (2005-2014) for the CAISO controlled SCE grid. The purpose of the Expansion Plan is to evaluate the performance of the transmission system under heavy summer and spring load conditions of 2005 through 2014, identify transmission constraints, if any, under expected stressed conditions, and determine transmission facilities needed to meet the CAISO Planning Criteria.

The Reliability Must Run of the SCE sub-areas was evaluated to determine long lead time (more than one year) system upgrades for the 2006-2009 periods. Additionally, planning scenarios for potential generation retirement were also evaluated as part of the CAISO coordinated planning process. Assessing the implications for electric service reliability from expected retirement of aging steam generation units in the LA Basin area will identify the need for major transmission facilities that will require long term process such as licensing activities, major constructions and site acquisitions for new substations and transmission lines.

The vulnerability of SCE’s transmission system to voltage collapse due to induction motor loads was investigated. The new load model for induction motor was benchmarked against an actual event that occurred on July 24, 2004. The studies conducted for the Expansion Plan, generally include load flow, voltage stability (post transient voltages and QV margins), transient stability, and short circuit studies.

The following are significant findings and recommendations of the 2004 Transmission Expansion Plan:

Big Creek SPS for N-1 Contingencies (2005-2008)

Install necessary equipment to implement 12-cycle tripping of Eastwood and Mammoth generation upon loss of either Big Creek 1-Rector, Big Creek 3-Rector, or Big Creek 3-Springville 230-kV line due to transient voltage problems at Rector.

Rector SPS for N-2 Contingencies (2005-2008)

Install necessary equipment to implement load shedding at Rector Substation upon simultaneous loss of common-corridor 230-kV lines from Big Creek to Rector, from Rector to Vestal, and from Magunden to Vestal.

Antelope 79 MVAR 230 kV Capacitor Bank (2006)

Install a new 79 MVAR 230 kV capacitor bank at Antelope to mitigate both posttransient voltage and transient stability criteria violations resulting from the simultaneous loss of Antelope-Vincent and Antelope-Mesa 230 kV lines.

Victor-Cottonwood Loop Project (2006)

This project is required to eliminate base case overload of the Victor-Savage 115 kV line due to higher load forecast in the Victorville/Apple Valley area. The existing Victor-Cottonwood 115 kV line will be looped into Savage, forming Victor-Savage #2 and Cottonwood-Savage 115 kV lines. Note that the Victor-Cottonwood 115 kV line is not part of CAISO's controlled facilities; therefore, CAISO's approval is not required.

RECENTLY APPROVED PROJECTS

With the exceptions of Devers-Mirage System Split and Viejo 230/66 kV Substation projects, the following transmission projects have been independently submitted to the CAISO for review and approval during 2004-2005, due to the urgency of the problems identified and short project lead time. The Cross Valley Rector Loop Project had been submitted and approved as an addendum to the 2003 Expansion Plan.

Lugo-Serrano 500 kV Line Loop Project (2006)

The SOL congestion problems had been identified and addressed in previous SCE Expansion Plans. A transmission project was completed to improve the SOL capability to 5,100 MW in 2004. However, unexpected generation shutdown due to maintenance, retirement and/or mothball announced late last year resulted in actual SOL congestions in late spring 2004.

In order to provide immediate to near term solutions to the SOL congestion problems addressed above, the Lugo-Serrano 500 kV Loop Project was recommended and approved in September 2004.

Valley VAR Support Project (2006)

Studies indicated WECC/NERC reliability criteria violations in transient voltage dip (25% first swing voltage drop at load bus) and post-transient/post-disturbance voltage deviation limits (WECC criteria limit is 5% and SCE planning criteria is 7% for N-1) during a line fault at Valley with subsequent clear of the Valley-Serrano 500kV line. (2006)

Cross Valley Rector Loop Project (2008)

In order to mitigate the transient stability criteria violation identified under loss of any one Big Creek-Rector 230-kV line and post transient voltage deviation criteria violations identified under simultaneous outage of the Big Creek1-Rector and Big Creek3-Rector 230 kV lines, this project will eliminate identified reliability criteria violations in this area of the grid for at least the next ten years. The previously approved project consists of constructing a new 15 to 20 mile 230 kV transmission line that would connect the existing Big Creek 3 – Springville 230 kV line into Rector Substation in 2008. The project also includes the installation of a 175 MVAR 230 kV Static Var Compensator (SVC) at Rector in 2006.

Devers-Mirage System Split (2008)

This project was needed to mitigate base case overload of the Mirage-Tamarisk 115 kV line under peak load and high path 42 flow conditions. Due to environmental issues, the operating date has been delayed to 2008 from 2006.

Rancho Vista 500/230 kV Substation Project (2009)

Due to high load growth in the eastern LA basin area, the need for additional transformer capacity at Mira Loma had been identified. The new 500/230 kV Rancho Vista substation, located next to the existing Etiwanda substation, will provide added transformer capacity in the area and help relieve contingency overloading on the Mira Loma 500/230 kV transformer banks with a parallel unit out of service under summer peak load conditions.

OTHER SIGNIFICANT TRANSMISSION PROJECTS

Except for the Pardee-Pastoria 230 kV Reconductor project, the following significant transmission projects in the SCE area have been previously reviewed and approved in other stakeholder forums (e.g. LARS, STEP, etc.), outside the SCE 2004 Expansion Plan stakeholder process.

Mira Loma-Etiwanda 230 kV Line Reconductor Project (2005)

This line reconductor project was approved in 2004 as part of the Local Area Reliability Service (LARS) process to eliminate 640 MW of Reliability Must Run (RMR) in the eastern LA basin area. The Mira Loma-Etiwanda 230 kV T/L will be upgraded to 2B-1033 ACSR from 1B-1033 ACSR, increasing its normal rating to 1287 MVA from 988 MVA.

Pardee-Pastoria 230 kV Line Reconductor Project (2006)

This project is part of an Infrastructure Replacement Program that upgrades old and failing facilities. The project replaces existing 605 ACSR conductors south of Pastoria with new 666.7 ACSS/TW conductors. This project increases south of Pastoria path capacity from approximately 1050 MVA to approximately 1470 MVA.

Path 49 Series Capacitor Upgrades (2006)

The Series Capacitor Upgrades project consists of upgrading to existing series capacitors on Devers-Palo Verde No. 1 and Hassayampa-North Gila-Imperial Valley 500 kV line to increase their combined ability to transmit power by 505 MW.

Tehachapi Wind Generation Interconnection Project (2007)

A new 230-kV transmission facility will be built between Pardee Substation and Antelope Substation in order to accommodate a new generating facility that will be interconnecting at Antelope. This new transmission line is expected to be in service in 2007.

As part of the ongoing Tehachapi area conceptual transmission planning study group process, this line will be built with 500-kV construction but initially energized at 230-kV in order to accommodate the anticipated long-term renewable resource development in the Tehachapi area. The other two segments of the Tehachapi area conceptual transmission plan are

Antelope-Vincent and Antelope-Tehachapi T/Ls. The CPCN application for the Tehachapi transmission plan was filed with CPUC by SCE in December 2004.

Devers-Palo Verde No. 2 Project (2009)

The construction of the second Devers-Palo Verde 500 kV line is needed to increase import capability by 1200 MW from Palo Verde/Arizona into California. The additional import capability will allow more economical surplus energy around the Palo Verde Area and improve the competitive generation market by bringing in a substantial amount of generation from more efficient new combined cycle generation to participate in the California generation market. The increase in import capability for external generation resources could also provide replacement of generation capacity being retired in California.

Northern California Area

This section summarizes PG&E's Transmission Expansion Plan for the next five to ten years (2005 to 2014). In addition to evaluating reliability performance over the required minimum five-year planning horizon, PG&E further analyzed its system out to 10 years and quantified the impact of future transmission projects to reliability-must-run (RMR) requirements.

For generators that are needed to maintain local area reliability, the CAISO has been utilizing RMR contracts to maintain reliability and to curb the market power of such generators. PG&E and the CAISO have been working on integrating the expansion planning effort with the Local Area Reliability Service (LARS) process to ensure that future transmission expansion projects are better optimized to meet the demand of the grid as well as reducing RMR requirements. As a result, PG&E has included an area-by-area analysis of the projected RMR requirements for the years 2006 – 2009. The intent of this analysis is to supplement the CAISO's LARS process and to identify potential longer-term transmission upgrade proposal that could be analyzed further in the future.

In the most recent Expansion Plan, PG&E has a total of 90 transmission projects. These projects are categorized as: 1) transmission project proposals seeking ISO approval - 15 projects, 2) transmission projects previously approved by the ISO – 75.

The fifteen transmission project proposals seeking CAISO approval are presented listed below:

Table 1:

#	Transmission Capacity Project Seeking Approval	Proj. No.	Project Origination	Project Classification	Planned Operation Date	Scope	Cost ($M)
1	Dumbarton - Newark 115 kV Reconductoring	T846A	CAISO Action Plan	New	May 2006	Reconductor Lines	5 to 7
2	Bair – Belmont 115 kV Reconductoring	T081A	CAISO Action Plan	New	May 2007	Reconductor Lines	3 to 5
4	Metcalf – Monta Vista 230 kV Nos. 1 and 2 Reconductoring	T647A	CAISO Action Plan	New	May 2007	Reconductor Lines	9 to 12
3	Ravenswood Reactive Support	T790B	CAISO Action Plan	New	May 2007	Install Voltage Support	9 to 11
5	Davis – UC Davis 115 kV Conversion	T177A	2004 Expansion Plan	New	May 2006	Convert 60 kV Facilities for 115 kV Operation	3 to 6
6	Moss Landing – Salinas 115 kV Reconductoring	T697	2004 Expansion Plan	New	May 2006	Reconductor Lines	5 to 8
7	Vaca Dixon 115/60 kV Transformer	T783A	2004 Expansion Plan	New	May 2006	Install 115/60 kV Transformer	6 to 10
8	Kasson – Lammers 115 kV Reconductoring	T680A	2004 Expansion Plan	New	May 2007	Reconductor Lines	1 to 2
9	Newark 230 kV Bus-Tie Upgrade	T944	2004 Expansion Plan	New	May 2007	Reconductor bus and upgrade breaker	< 1
10	Pease – Marysville 60 kV Line	T815	2001 Expansion Plan	On-Going	May 2007	Construct 60 kV Line	8 to 9
11	Vaca Dixon 500/230 kV Transformer	T783B	2004 Expansion Plan	New	May 2007	Install 500/230 kV Transformer	30 to 35
12	Lakeville 230/60 kV Transformer	T571	2003 Expansion Plan	On-Going	May 2008	Install 230/60 kV Transformer	6 to 10
13	Palermo – Rio Oso 115 kV Reconductoring	T686	2003 Expansion Plan	New	May 2008	Reconductor Lines	20 to 30
14	Brighton 230/115 kV Transformer	T758A	2004 Expansion Plan	New	May 2009	Replace 230/115 kV Transformer	6 to 8
15	Herndon – Bullard 115 kV Reconductoring	T122	2004 Expansion Plan	New	May 2009	Reconductor Lines	6 to 8

Long-term planning studies were performed as well as projects that are in their preliminary planning stages. The majority of these projects are considered outside the five-year planning horizon, but may be critical in the future years to meet grid reliability. These projects were not submitted for CAISO approval, but were included as information for the CAISO and expansion plan stakeholders.

San Diego Area

This section documents SDG&E's Grid Assessment and Transmission Expansion Plan (2004 Grid Assessment) utilizing transmission models for 2005-2009 as well as a 2014 ten-year planning horizon model.

As of the date of this report SDG&E is proceeding with the construction, design, and/or permitting of transmission and substation addition/upgrade projects that have been approved by the CAISO through earlier grid assessment review processes or other ISO approval processes.

Major developments in SDG&E's 2004 grid assessment include:

- Obtaining the CAISO Board Directive to install the Path 49 Upgrade projects.
- SDG&E's identification of need for a proposed second 500 kV transmission line interconnection into San Diego.
- Acceleration of a temporary configuration (to 2005) of the Miguel-Mission #2 230 kV transmission project
- Palomar Energy Project (2006) includes a new 230 kV switchyard at the generator location.
- Otay Mesa Generation Project (2007) and a new 230 kV switchyard, an additional circuit from Otay Mesa to Miguel 230 kV switchyard. Two additional 230 kV lines from the Otay Mesa/Miguel area (associated with the PPA) terminating at SDG&E's Old Town and Sycamore Canyon substations.

b. Planning Issues

Historically, the CAISO transmission planning process consisted of the following steps:

1. The Participating Transmission Owners (PTOs) submitted yearly transmission assessment and expansion plans to the CAISO covering the next five years in detail plus a tenth year. The CAISO reviewed the assessment to ensure it was adequate. The expansion plans were reviewed to determine if the proposed projects: (1) solved an identified problem, (2) were the best alternative from a system point of view, and (3) were the most economical alternative.
2. CAISO Management approved projects that met the CAISO evaluation criteria and had an estimated cost below $20 million or submitted the project for CAISO Board approval if they had an estimated cost exceeding $20 million.
3. Additionally, the CAISO combined the individual PTOs plans submitted into one and performed an independent and comprehensive analysis to make sure that "nothing fell through the cracks".

4. Finally, the CAISO conducted studies to determine Reliability Must Run (RMR) Generation requirements.

For the most part, the above process forced the CAISO to be reactionary in part because the CAISO only acted on those projects submitted to the CAISO by the PTOs for approval. Decisions to pay RMR costs or to build facilities to avoid RMR costs had been largely left to the PTOs. Further, transmission expansion projects to mitigate congestion costs within the CAISO control area had frequently been completed after significant congestion costs had already accrued.

The CAISO is proposing a new planning process that allows the CAISO to evolve from a predominantly reactionary role to a proactive planning role. Because the CAISO has confidential economic data that is needed for transmission analysis purposes that the PTOs do not have authorization to use, the CAISO is in a position to use this data to provide a more comprehensive basis for determining the economic impact of congestion and RMR-type costs that the PTOs are expected to incur. This information can further support decisions about new facilities that would provide economic and/or reliability benefits to the ratepayers. As such, the proposed CAISO planning process can be more centralized to facilitate the design of proposed solutions that will maximize benefits for all CAISO market participants. Active participation is needed from the PTOs and market participants to ensure the CAISO has all the relevant information it needs to design these solutions, and PTO and market participants have the information they need to implement their respective plans.

With this background in mind, the CAISO will prepare an annual five-year project-specific plan and a ten-year conceptual plan that will identify projects that CAISO studies indicate enhance grid operations and should be built for economic and/or reliability reasons. The projects will be selected to minimize costs when it can be demonstrated that the project costs are lower than the congestion or RMR-type costs. Once the projects are identified, they will be submitted to the PTOs for evaluation. The transmission plan will account for new load growth, new generation resources, and generating plant retirements. Interim approval for the exploratory activities associated with projects that are still at the conceptual level may be necessary.

It is expected that the initial CAISO five and ten-year plans will be provided for stakeholder review prior to January 2006 and finalized shortly thereafter. New PTO plans based on the CAISO studies should be submitted to the CAISO by July 1, 2006.

The CAISO will develop a process to obtain input to our planning assumptions, particularly the resource portfolio scenarios in the mid to long-term time frame (five to ten years). Some assumptions may be based on contracts, some will be based on best guess, and others may be based on a typical mixture of portfolio. This should be the output of a consultation workshop with the PTOs and market participants that will be sponsored by the CAISO.

The PTOs annual plans will be evaluated to determine if the CAISO projects are part of the PTO’s submission. If they are, CAISO management or the CAISO Board of Governors will approve the projects. The PTOs will have an opportunity to assess the CAISO’s projects and determine if they have alternative projects that are more effective than those proposed by the CAISO and that those projects provide equal or superior benefits. The CAISO will evaluate those alternative projects.

If any of the projects that the CAISO has determined must be constructed are not part of a PTO plan, the PTO in the area where the project is needed will be asked to build the project on a right of first refusal basis. If the PTO declines to build the project, then the opportunity will be offered to third-party investors. It is understood that a competitive process for awarding projects to third parties will need to be developed with regulatory oversight.

In conclusion, the object of this new process is to proactively eliminate congestion and reliability must run types of generation contracts everywhere that it makes economic sense to do so, resulting in a robust transmission system that will benefit all CAISO ratepayers. Additionally, it will serve as a locational signal to generators for developing resource opportunities in locations that would resolve transmission bottlenecks. In this regard, a locational credit can be designed to encourage siting in the right location for an annual transmission credit based on performance. The credit should not exceed a reasonable portion of the cost of the transmission solution. This, in effect, could re-establish the integrated planning approach under the restructured market in a more meaningful manner as compared to the old model under the vertically integrated structure.

c. Statistics

i. Load Growth

Electric demand and power factor modeled in the base cases represent projected summer peak load conditions. The regional study base cases incorporate a 1-in-5 year adverse weather assumption based on ambient temperature. Similarly, local area base cases incorporate a 1-in-10 year adverse weather assumption. The following two tables show the 1-in-5 load projections for the CAISO system and recent actual load growth rates.

Table 2: CAISO 1-in-5 Load Projections

	2006	2009	2014
	MW	MW	MW
Northern California	26,607	27,865	30,235
Southern California	23,305	24,675	26,743
San Diego Area	4,462	4,716	5,078
Coincident CAISO	47,171	49,314	53,656

Table 3: CAISO Load Growth Rates From 2001 to 2004

Year	Annual Peak Demand	Percentage Change
	(MW)	
2001	38,975	-5.4
2002	42,352	8.7
2003	42,581	0.5
2004	45,562	7

ii. Interconnection Queue

When this section of the report was drafted there were 88 generation projects representing over 23,000 MW of potential generation capacity actively being processed within the CAISO generation interconnection queue. With the recent implementation of resource adequacy and renewable generation requirements by the California Public

Utilities Commission, the amount of activity in the ISO queue noticeably increased. The most recent interconnection queue information can be found on the CAISO website using the following link: http://www.caiso.com/14e9/14e9ddda1ebf0.pdf

iii. Transmission Build

There have been 337 transmission expansion projects approved by the CAISO representing over $3 Billion in facility investments, since 1998. Although over $1 Billion of these projects are in operation today, many of the largest projects are still in the construction or permitting phase.

iv. Resource Adequacy

The California Public Utilities Commission has ruled that investor owned utilities (IOU) that comprise the majority of the CAISO load, must procure to long-term planning reserve margins of 15 percent to 17 percent (resource adequacy targets). The CPUC uses Procurement Review Groups (identified separately for each IOU), made up of non-market participant and state agency representatives, to monitor certain technical aspects of each IOU's procurement practices and advise the CPUC.

The CPUC also requires that, "until a 20 percent eligible renewable resources portfolio is achieved," each IOU must procure renewable energy resources with the goal of adding at least an additional 1 percent per year.32 This annual procurement requirement is conditionally limited by sufficient public goods charge funds available to cover the above-market costs for renewable energy. Reaching annual renewable energy portfolio targets may, therefore, be contingent upon adequate amounts of available cost-competitive renewable options in the market place.

Existing IOU procurement plans, guided by CPUC requirements, are a mix of short-, medium-, and long-term bilateral contracts in addition to some new generation that will be utility-owned and placed in the rate base.

ERCOT

a. Summary of Most Recent Plans

Summaries of ERCOT's most recent plans can be found in its "Report on Existing and Potential Electric System Constraints and Needs", published annually in October. This report can be found at:
http://www.ercot.com/NewsRoom/MediaBank/ERCOT2005ReportOnConstraintsAndNeeds10102005.pdf

b. Planning Issues

Significant planning issues current facing ERCOT include:

Renewable Energy Zones

On August 1, 2005, Texas Governor Rick Perry signed legislation, known as SB 20, which mandates the addition of 3,000 MW to the current 2,880 MW goal of renewable generation capacity. The act also extends the deadline for the renewable capacity additions from 2009 until 2015. While the act does dictate that 500 MW of this goal is to be obtained from non-wind sources, it is expected that the remaining capacity requirement will be met utilizing wind resources. As a result, SB 20 also requires the Public Utility Commission of Texas (PUCT) to work with ERCOT to establish "competitive renewable energy zones" and plan for sufficient transmission capacity to these zones ahead of actual generation interconnection requests. ERCOT planners are currently developing this study which is tentatively scheduled to be released by the end of 2006.

Reliability Must Run

When a generation owner within the ERCOT decides to either mothball or decommission a generation unit, the owner is required to file with ERCOT planners and the market a "Notification of Suspension of Operations" request. ERCOT planners then have 90 days to review and determine the need if that generation is needed to maintain system reliability. If a unit is deemed necessary for reliability support, ERCOT will then execute a Reliability Must Run (RMR) contract with the generation owner for the continued use and need of the unit. The costs of each of these RMR contracts are then uploaded to the ERCOT market. In order to reduce or eliminate this uplift costs, ERCOT planners are also required to develop an "exit-strategy" of improvements which will allow the RMR contracts to be discontinued. For 2005, ERCOT planners have evaluated approximately 30 "Notification of Suspension of Operations" requests. As of October 1, 2005, ERCOT has 1,421 MW of generation capacity under RMR contract.

Transition to Nodal

At present, the ERCOT market is structured as a zonal market. In an effort to facilitate market efficiency and to improve congestion cost allocation, the PUCT is considering a rulemaking that will require the transition of the ERCOT market from Zonal to Nodal. ERCOT planners are working to determine the overall impact this change will have on planning and operational models. This comprehensive planning study is scheduled to be completed and filed with the PUCT in January 2006.

Congestion Costs

ERCOT categorizes congestion as one of two types – zonal or intrazonal (local). Zonal congestion costs result when ERCOT has to redispatch generation between zones to reduce the loading of a Commercially Significant Constraint (CSC), generally a 345kV line which acts as an interface between two neighboring zones. Zonal congestion costs are directly assigned on a pro-rata basis to those market participants scheduling energy across the CSC.

Interzonal or local congestion occurs when the lack of sufficient transmission infrastructure in a given area (with a single congestion zone) results in a limitation, or bottleneck of the flow of energy into or within that area. Intrazonal congestion costs result when ERCOT has to redispatch generation within the zone to reduce the transmission flows and improve voltage profiles. Interzonal congestion costs are uplifted to all load-serving entities within ERCOT.

ERCOT planners, working in conjunction with Transmission Service Providers (TSP) have reduced Zonal congestion costs from over $80 million in 2001-02 to less than $30 million in 2004-05; whereas Intrazonal (local) congestion costs have been reduced from over $360 million in 2003-04 to less than $250 million in 2004-05. A significant number of the planned transmission projects currently proposed, or under review, by ERCOT planners are intended to continue to reduce or eliminate congestion costs.

NERC Reliability Standards

ERCOT planners continue to support the development of the new NERC Reliability Standards and in assessing the impact on ERCOT of the 2005 Federal Energy Bill.

Timeliness/Accuracy of Data

The results of system planning efforts are only as good as the data used to develop the models and forecasts required for these efforts. ERCOT is working with its Market Participants to improve its forecasting methodologies and both short-and long-term system planning models.

Timeliness of Transmission Expansion

ERCOT planners, like all planners, develop a comprehensive time-line of needed projects. However, since ERCOT does not control the actual construction of these projects, ERCOT planners must continually assess the progress of these projects to determine any remedial actions (if necessary) and to keep planning models up-to-date. ERCOT planners are actively working with transmission providers to improve construction reporting.

c. Statistics

The ERCOT region includes approximately 200,000 square miles of Texas. The area is very diverse—topographically, climatology, and demographically. From 1999 to 2004, the population of Texas has grown 12.5% (2.4% per year). Approximate ERCOT boundaries are shown in figure below.

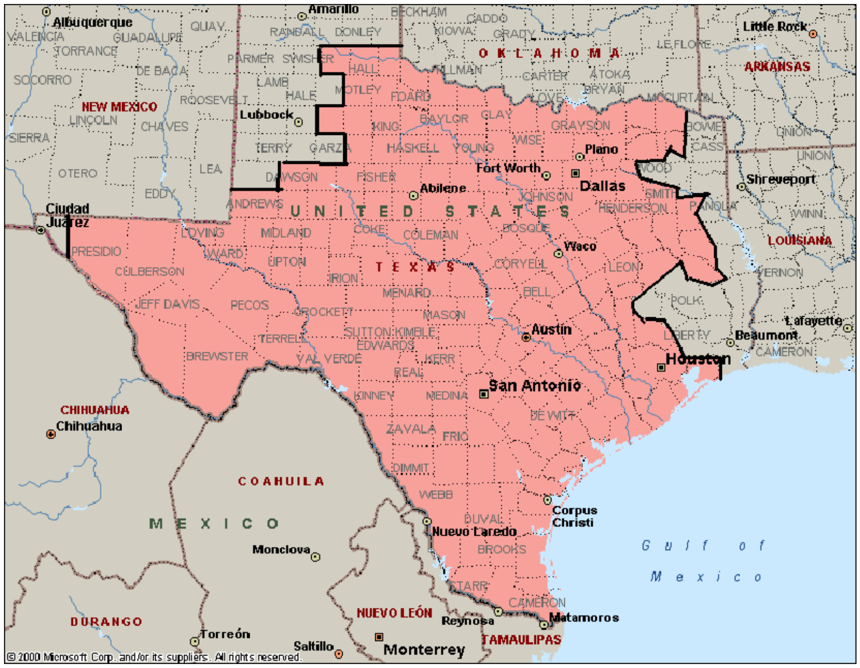

Figure 1: ERCOT Boundaries

As shown in the figure, ERCOT represents a bulk electric system located totally within the State of Texas and serves approximately 85% of the electrical load in the state. ERCOT is a summer peaking system due to hot weather combined with a high saturation of air conditioning.

i. Load Growth

Portions of the ERCOT system have been among the fastest growing areas in the United States over the past decade especially along the lower Rio Grande border with Mexico, the San Antonio-Austin-Waco corridor, Houston, and the Dallas-Ft. Worth metroplex area. As a result, ERCOT has experience significant load growth in electrical demand. Between 1994 and 2005 ERCOT peak demand has grown 34.7% (15,117 MW) with an all-time record for ERCOT's peak demand set at 60,272 MW on August 23, 2005. Current ERCOT load forecasts for 2006 through 2011 indicate an expected annual load demand growth of approximately 1.6%.

From 1999 to 2004, ERCOT has experienced a 1.5% annual growth rate in electric energy consumption and this growth rate is expected to continue through the 2011 forecast period.

ii. Interconnection Queue

Since 1999, ERCOT has received more than 200 requests for generation interconnection within the ERCOT region of Texas. Factors which appear to continue to attract merchant plant activity within ERCOT include: revisions to the PUCT transmission rules regarding generation interconnection, wholesale and retail market deregulation, renewal of the Production Tax Credit, and the state's overall healthy economy. The table below provides the generation interconnection requests under development by ERCOT as of October 1, 2005.

Table 1: ERCOT Generation Under Development

Active Generation Interconnection Requests	Total ERCOT
Security Screening Study (SSS)	3
SSS Completed	4
Full Interconnection Study (FIS)	29
FIS Completed	2
Interconnect Agreement Completed	16
Capacity, MW	14,650
Wind, MW (under development)	6,349

iii. Transmission Build

Since 1999, ERCOT TSPs have completed over 153 significant transmission improvement projects, adding over 3,000 circuit miles of new or improved transmission, costing over $2.2 billion dollars. Transmission improvement projects now being considered by ERCOT planners to be constructed over the next six years are expected to improve 4,500 circuit miles of transmission lines and add 31,400 MVA of autotransformer capacity, costing an estimated $2.8 billion dollars (2005 dollars). Selected 345 kV projects are shown in the figure and table below.

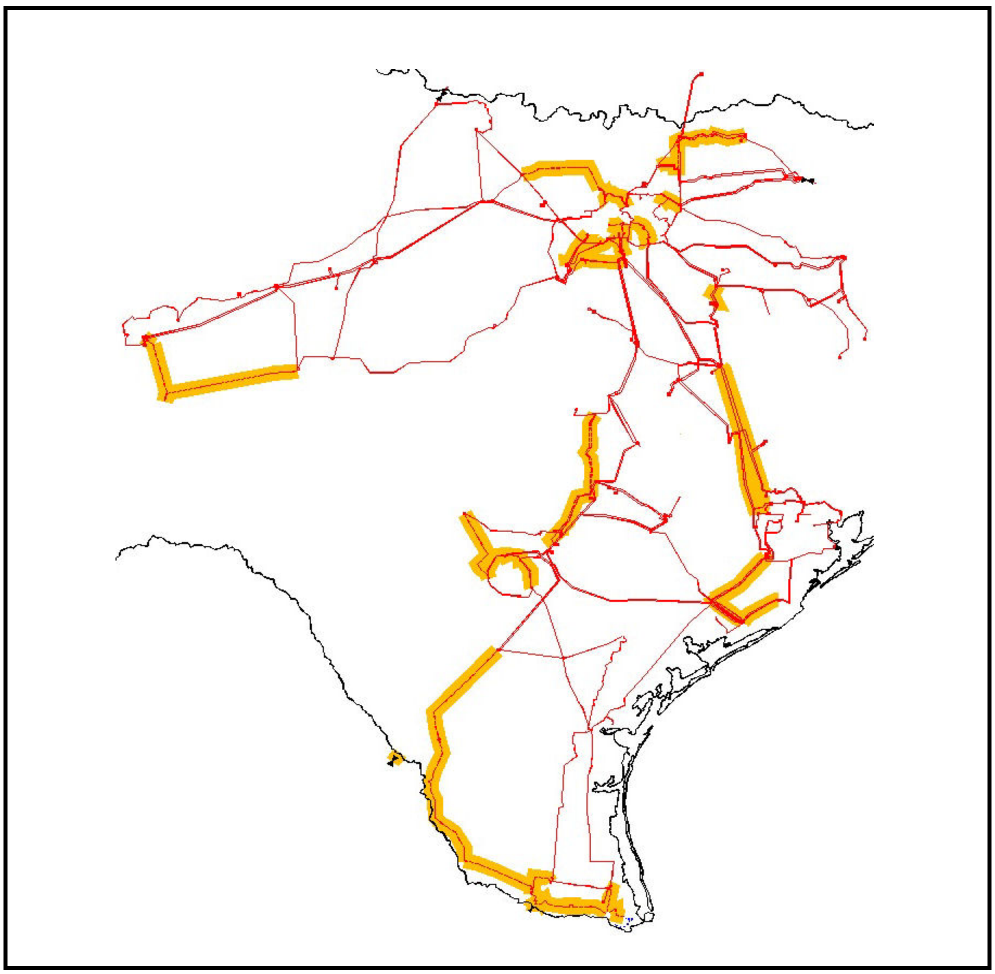

Figure 2:

Table 2: ERCOT Transmission Projects in Progress or under Review

Project Title	Project Description	Projected In-Service Date	kV	Location County
Watermill - W. Levee (2nd) 345 kV circuit	Install Watermill - W. Levee (2nd) 345 kV circuit	Oct-05	345	DALLAS
Zorn Auto	Replace the 600MVA Zorn Auto 2 with a 478MVA auto (7045-7180)	Oct-05	345	GUADALUPE
Bellaire 345/138kV autotransformer	Upgrade Autotransformer (A1) position to increase thermal ratings	Nov-05	345	HARRIS
Bellaire 345/138kV autotransformer	Upgrade Autotransformer (A4) position to increase thermal ratings	Nov-05	345	HARRIS
T.H.Wharton - Jewett ckt.1	Upgrade tie lines from TH Wharton to TXU tie point to increase thermal ratings to 1450 MVA by raising conductors and upgrading limiting equipment at TH Wharton	Dec-05	345	HARRIS
Laredo BTB Station, Rebuild and convert line to CFE to 230 kV.	Construct 150 MW CFE asynchronous interconnection and 138 kV switching station.	Mar-06	230	WEBB
Rio Hondo, add 345/138 kV auto	Rebuild La Palma to Rio Hondo 138 kV with 2-795 ACSS, double circuit capable and add 345/138 kV autotransformer at Rio Hondo	Apr-06	345	CAMERON
Rio Hondo, add 345/138 kV auto	Rebuild La Palma to Rio Hondo 138 kV with 2-795 ACSS, double circuit capable and add 345/138 kV autotransformer at Rio Hondo	Apr-06	345	CAMERON
Temple Pecan Creek Switching Station	Establish Temple Pecan Creek Switching station and install a 600 MVA 345/138 kV autotransformer.	May-06	345	BELL
Venus - Sherry 345 kV line	Construct Venus - Sherry 345 kV line	May-06	345	ELLIS
W. Levee - Norwood 345 kV line	Construct W. Levee - Norwood 345 kV line	May-06	345	DALLAS
Venus - Liggett 345 kV line	Construct Venus - Liggett 345 kV line	May-06	345	ELLIS
Venus - Johnson Switch 345 kV line	Upgrade existing 345 kV line	May-06	345	ELLIS
Valley 345/138 kV autotransformer	Replace existing 450 MVA 345/138 kV autotransformer with a 600 MVA autotransformer	May-06	345	FANNIN
Jewett - TH Wharton 345 kV line upgrade	Upgrade tie lines from Jewett to TXU Electric Delivery tie point to increase thermal ratings to 1450 MVA or above.	May-06	345	LEON
Jewett - Tomball 345 kV line upgrade	Upgrade tie lines from Jewett to TXU Electric Delivery tie point to increase thermal ratings to 1450 MVA or above.	May-06	345	LEON
Ben Davis Sub: Add 345 terminal and install a 2nd 345-138 autotransformer	Expand 345 ring bus and add a 2nd 345-138 kV autotransformer	May-06	345	DALLAS

Project Title	Project Description	Projected In-Service Date	kV	Location County
Nelson Sharpe, add 345/138 kV autotransformer	Construct Nelson Sharpe 345/138 kV substation in the Lon Hill to Rio Hondo 345 kV line and add a phase-shifting transformer at Nelson Sharpe in Davis 138 kV line	May-06	345	KLEBERG
Greens Bayou 345/138 kV autotransformer.	Replace 400MVA Autotransformer (A1) at Greens Bayou with 800MVA and swap autotransformer (A1) and (A2) 138kV leads.	Jun-06	345	HARRIS
Addicks 345/138 kV autotransformer.	Add second 600MVA Autotransformer (A2) at Addicks.	Jun-06	345	HARRIS
Kendall-CPS Cagnon 345-kV line	Construct a 345 kV bundled 1590 ACSR line (approximately 45 miles) between Kendall (7046) and Cagnon (5056)	Jun-06	345	BEXAR
Clear Springs	Add a new 345/138 kV 478 MVA auto-transformer at the Clear Springs substation(7050). The existing 345 kV bus at the Clear Springs will be converted from a ring bus configuration to a double-bus double-breaker configuration. Upgrade the 7.2-mile Clear Springs(7680)-Geronimo(7604)-Seguin(7228) 138 kV transmission line (T-264) from 336 ACSR to Bundled 795 ACSR double circuit capable. Upgrade the 7.2-mile Clear Springs(7680)-Freiheit(7462)-Hortontown(7175)-Comal(7176) 138 kV transmission line (T-264, T-394, and T-119) from 336 ACSR to Bundled 795 ACSR double circuit capable.	Jun-06	345	GUADALUPE
Bellaire 345/138 kV autotransformer.	Add 800MVA autotransformer (A2) at Bellaire, swap ckt.05 to Jeanetta and ckt.09 to Brays at Bellaire and upgrade fault duty rating of Bellaire North 138kV bus to at least 63kA.	Jun-06	345	HARRIS
Tomball two 345/138 kV autotransformers.	Replace two 600MVA Autotransformers (A1) and (A2) at Tomball with two 800MVA autos.	Jun-06	345	HARRIS
Skyline - Replace 345kV Autotransformer #2 & #4	Replace the two 480 MVA autotransformers(#2 & #4) with one 600 MVA autotransformer.	Jul-06	345	BEXAR
Elm Creek Substation	Install new 345 kV switching station at the intersection of the existing 345kV lines from STP-Skyline, STP-Hill Country, and both lines from Marion to San Miguel.	Oct-06	345	GUADALUPE

Project Title	Project Description	Projected In-Service Date	kV	Location County
Elm Creek Reroute	Reroute 345kV lines (STP- Skyline, STP- Hill Country, Marion, San Miguel) to connect with future Elm Creek Switchyard	Oct-06	345	GUADALUPE
Jacksboro Switch - W. Denton 345 kV line	Construct Jacksboro Switch - W. Denton 345 kV line	Dec-06	345	JACK
Sandow 345/138 kV autotransformer	Install second 345/138 kV autotransformer	Dec-06	345	MILAM
Odessa EHV 345/138 kV 300 MVA autotransformer replacement	Replace existing 300 MVA 345/138 kV autotransformer with a 450 MVA autotransformer	Dec-06	345	ECTOR
Paris Switch - Anna 345 kV line	Construct Paris Switch - Anna 345 kV line	Dec-06	345	LAMAR
P.H. Robinson 345/138 kV autotransformer.	Replace 500MVA Autotransformer (A3) at P.H. Robinson with 600MVA.	Dec-06	345	GALVESTON
West Denton Sub: Construct 345 bus, add 2 line terminals and add a 2nd 345 auto	Expand 345 kV breaker and a half substation with line terminals for the Jacksboro line and N.W. Carrollton line. Add a 2nd 345-138 kV autotransformer	Dec-06	345	DENTON
DeCordova - Benbrook 345 kV line upgrade	Upgrade capacity of line	May-07	345	HOOD
DeSoto 345/138 kV autotransformer	Install a 600 MVA 345/138 kV autotransformer at DeSoto	May-07	345	DALLAS
Plano Tennyson 345/138 kV autotransformer	Install a 600 MVA 345/138 kV autotransformer at Plano Tennyson	May-07	345	COLLIN
Trinidad - Richland 345 kV line	Upgrade Trinidad - Richland 345 kV line	May-07	345	HENDERSON
Venus - Cedar Hill 345 kV line	Upgrade existing 345 kV line	May-07	345	ELLIS
Ben Davis - Royse 345 line: Reconductor	Reconductor 17 miles of line to increase capacity	May-07	345	Dallas
WAP 345 kV sub.	Upgrade fault duty rating of WAP 345 kV to at least 63kA	Jun-07	345	FORT BEND
Smithers 345 kV sub.	Upgrade fault duty rating of Smithers 345 kV to at least 63kA	Jun-07	345	FORT BEND
STP - Dow ckt.18 and ckt.27	Replace 2000 Amp equipment on both circuits from STP to DOW.	Jun-07	345	MATAGORDA
Spruce to Skyline 345kV 2nd Circuit	Build 2nd 345 kV line from Spruce to Skyline substation	Jun-07	345	BEXAR
Hillje Switching Station	Build a new 345 kV Hillje substation. Loop ckt.1 STP-Holman into the new substation.	Jun-07	345	WHARTON
STP - Hillje ckt.	Build new 345 kV line from STP to Hillje.	Jun-07	345	MATAGORDA
WAP - Hillje ckt.	Build new 345 kV double circuit line from WA Parish to Hillje.	Jun-07	345	FORT BEND
Second Whitney 345/138 Autotransformer	Install second 450MVA 345/138KV auto at Whitney	Jun-08	345	BOSQUE

Project Title	Project Description	Projected In-Service Date	kV	Location County
Spruce 2 Power Plant loop	Install new 345kV connection between Spruce 2 and CPS Energy grid.	Jun-08	345	BEXAR
Increase CNP 345/138 kV autotransformer capacity	Add several 800 MVA autotransformers in the CNP transmission system	Dec-08	345	HARRIS/CHAMBERS/FORT BEND/GALVESTON/BRAZORIA
West Denton - NW Carrollton 345 kV circuit	Add second Circuit from West Denton to NW Carrollton	May-09	345	DENTON
Skyline - Install a third 345kV Autotransformer	Install one 600 MVA autotransformer.	May-09	345	BEXAR
Second Concord 345/138 Autotransformer	Install second 300MVA 345/138KV auto at Concord	Jun-09	345	JOHNSON
Cagnon to Hillcountry 345kV 2nd Circuit	Build 2nd 345 kV line from Cagnon to Hill Country substation	Jun-09	345	BEXAR
Hill Country to Skyline 345 kV 2nd Circuit	Build 2nd 345 kV line from Hillcountry to Skyline substation	Jun-09	345	BEXAR
Dansby to Twin Oak 345 kV	Design and build a double circuit 345 that will tie into the existing TMPA Gibbons to Twin Oaks line	Jul-09	345	BRAZOS
2nd Lewisville Auto	Install (2nd) 345/138 kV autotransformer at Lewisville station	Dec-09	345	DENTON

The figure below provides a summary of all the transmission projects currently in progress within ERCOT. The figures indicate that significant 138-kV construction will be completed over the next four years. This is directly due to the needed infrastructure improvements (reliability requirements) and the number of RMR exit strategies being implemented. Multiple 345-kV/138-kV autotransformers will be installed through 2007 in order to increase the transfer capability from the 345-kV system to the 138-kV load-serving system. 345-kV additions are expected to increase dramatically in 2006 compared to previous and subsequent years. This increase is to due to the expected completion of several 345-kV projects in/around Dallas/Ft. Worth (DFW), Central Texas, South Texas, and southwest of Houston. In addition to the 345kV expansion, a significant number of voltage support/control devices (capacitors) along with system protection equipment (circuit breakers) are also being added to the grid through 2009.

It should be noted that total transmission plant investment within ERCOT through the 2005-2009 time period is expected to exceed the levels shown in the Figure below. This is due to ERCOT only tracking transmission system upgrade projects and does not track all other types of miscellaneous transmission investments, such as replacement of failed or obsolete facilities, transmission line relocations, relay system upgrades or additions, control center investment. Furthermore, many transmission upgrade projects have not yet been identified and therefore are not yet being tracked by ERCOT.

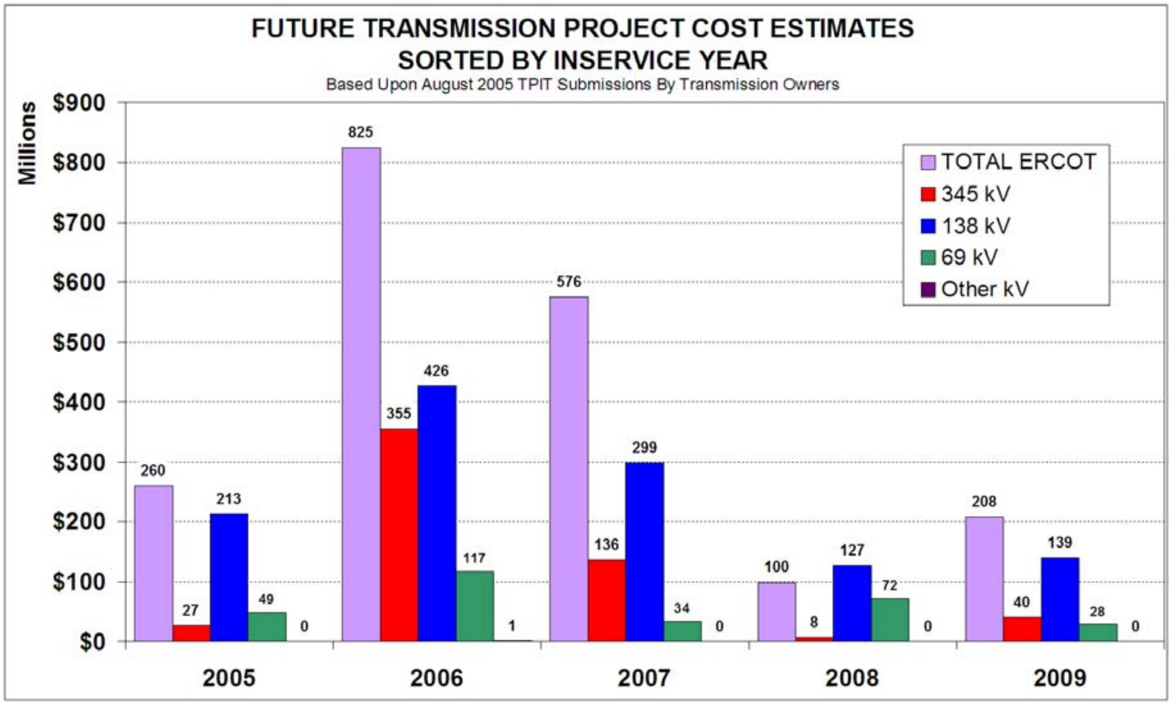

Figure 3: ERCOT Proposed Transmission Additions for 2005- 2009

iv. Resource Adequacy

ERCOT and its market participants are meeting the challenge to keep the ERCOT system reliable and adequate. Over 24,000 MW of new generation including wind power and over 3,000 circuit miles of transmission lines, and a significant number of autotransformer additions have been made to the ERCOT system since 1999.

The ERCOT Board of Directors recently approved a new methodology to determine Reserve Margin that recognizes that a generator's contribution to reserve is determined more by its availability than by its capacity rating.

Current reserve margins are expected to remain above the 12.5% minimum requirement set by the ERCOT Board, through 2009 as shown in the table below.

Table 3: ERCOT Capacity, Demand, and Reserves through 2010

	2006	2007	2008	2009	2010
Firm Load Forecast, MW	60,998	61,982	63,095	63,947	65,051
Resources, MW	69,287	70,274	72,463	72,484	72,460
Reserve Margin	13.6%	13.4%	14.8%	13.4%	11.4%

IESO

Note: The information provided for IESO Plan is currently based on the 10-Year Outlook Report. For more information on Outlooks visit the following IESO web-site link: http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp

The information provided below is subject to updates and revisions.

a. Summary of Most Recent Plans

There have been a number of positive developments in Ontario's electricity sector between publication of the 2005 10-year Outlook, posted August 15, 2005, and the previous 10-year Outlook published on March 31, 2004.

These new developments include the introduction of approximately 600 MW of gas-fired generation into the Ontario market, the decision to proceed with restarting Pickering Unit 1 (bringing an additional 515 MW on-line in October 2005,) and the announcement of 2,200 MW of new supply initiatives and 395 MW in renewable energy projects under the provincial government's recent Request for Proposals (RFP) process. All of the new supply resources announced under the RFP process are expected to be in service within the next four years.

The government has also clarified the timing associated with the commitment to phase out coal-fired generation, with the final units at the Nanticoke Generating Station expected to be removed from service in 2009.

In addition to the committed projects discussed above, there are a number of other projects which are in various stages of discussion, development, or negotiation. These projects include:

- The return to service of Bruce Generating Station (GS) Units 1 and 2 (~1,500 MW);
- Increasing the energy capability of Beck 2 GS by construction of a third tunnel (~200 average MW);
- The development of additional hydroelectric generation capacity in Northern Ontario (up to 400 MW);
- Recently announced plans for additional generation in downtown Toronto (500 MW) and the western Greater Toronto Area (1,900 MW), co-generation across the province (1,000 MW) and demand-side measures (250 MW);
- The development of conservation programs under the Ontario Power Authority (~1350 MW) ;
- The development of additional renewable generation to meet the Renewable Portfolio Standard of 2,700 MW by 2010; and
- Long-term power purchases from Manitoba and Newfoundland and Labrador.

Timely decisions on these projects will be key to ensuring that the coal shutdown can proceed as planned. Continuing progress toward establishing and meeting in-service dates is critical. The supply picture with the first four items listed above included – these being considered to be the more advanced projects – is provided in the chart "Resource Adequacy Outlook – Coal Replacement Scenario" found under Part b, Coal Replacement.

The provincial plan to phase out coal-fired generation in favour of cleaner forms:

Aging generation facilities and the continued increase in demand for electricity add to the urgency of proceeding with new generating and transmission facilities over the next 10 years.

Timely progress on the plans identified earlier is required to achieve this additional capacity Ontario requires if it is to ensure a reliable supply of electricity over the next decade and beyond.

The IESO 10-Year Outlook provides an assessment of the demand-supply picture for the province over the next decade and provides a plan identifying the timing and requirements of system changes needed to meet the government's coal shutdown timeframe. Under the provisions of Bill 100, the Ontario Power Authority (OPA) is responsible for long term forecasting. The OPA's first Integrated Power System Plan is expected to be delivered to the OEB as early as the summer of 2006.

b. Planning Issues

The IESO currently has a number of important planning issues that are under continuous review. They include, but are not limited to the following:

Ontario Demand Forecast

The government has set aggressive targets for energy conservation to reduce peak electricity consumption by 5 per cent by 2007. However, because the impact of new conservation initiatives is as yet difficult to forecast, the effects of conservation efforts are not reflected in the Ontario demand forecast used in the 10-Year Outlook. These conservation efforts can make a significant difference. Without them energy consumption is forecasted to grow from about 157 terawatt-hours (TWh) in 2006 to about 170 TWh in 2015, an average annual growth rate of energy of 0.9 per cent.

Normal weather peak demands are expected to increase from about 24,200 MW in 2006 to 26,900 MW in the summer of 2015, an increase of 2,700 MW. Under extreme weather conditions, the summer peak is projected to approach the 30,000 MW level by the end of the forecast period.

Coal Replacement

The Ontario government is committed to phasing out the remaining 6,500 MW of coal-fired generation in the province beginning in 2007 and ending in 2009 as replacement resources become available.

This transition represents the largest and most significant electricity system change ever undertaken in Ontario and involves major technical considerations. It also involves significant risks and challenges that need to be addressed.

The IESO will monitor and assess the coal shutdown and replacement resource plans and will provide advice to all parties regarding the actions or adjustments required to ensure reliability is maintained.

New generation units typically encounter more operating issues affecting their reliability for a period of time after they come into service. These can be significant. Accordingly, a critical requirement of the coal replacement plan is that while coal plants can be scheduled to stop running, those units will be held available for a period of time to operate if necessary to maintain reliability.

Coal supply makes up a large part of Ontario's flexible generation, and it has traditionally been required to meet changing demand, to supply demand when other supply sources are unreliable, and to balance load and generation at all times. The specific operating characteristics of new generation may require changes to current practices in order to provide operating flexibility and sustained energy production capability as and when it is needed.

The impact of new generation on the transmission system will also be assessed, and necessary transmission upgrades must be completed to ensure reliable system operation.

A plan outlined in the full 10-Year Outlook provides timing and requirements of system changes needed to meet the government's coal replacement objective.

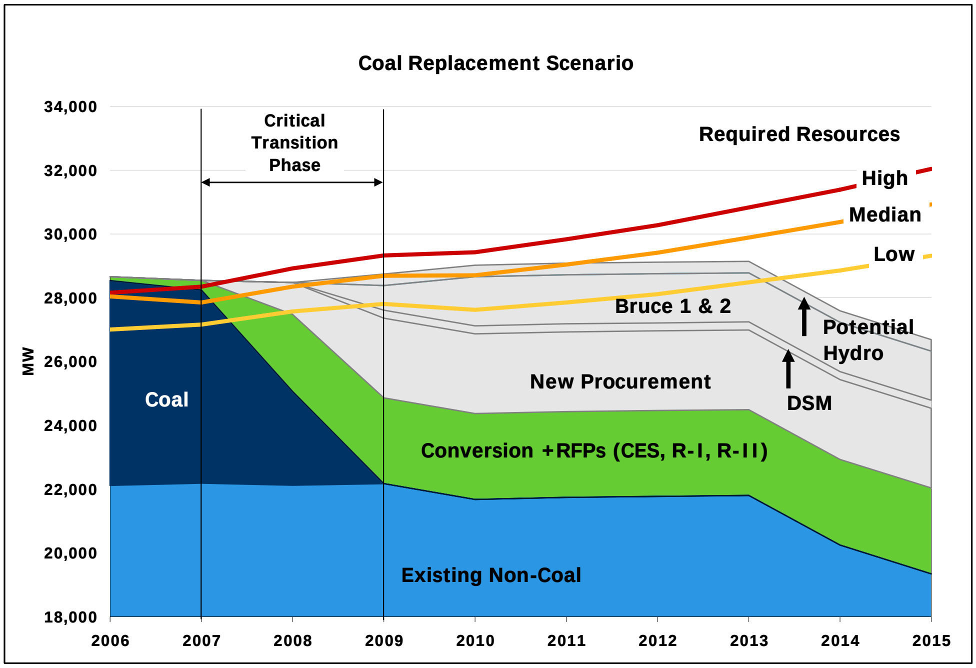

Figure 1: Resource Adequacy Outlook – Coal Replacement Scenario

Supply to Downtown Toronto

New generation and transmission facilities supplying the downtown Toronto area are urgently needed over the next few years to meet this area's growing need for electricity.

The government has requested that the OPA procure 500 MW of new supply to address the concerns raised in the last 10-Year Outlook about supply to downtown Toronto.

There is an increasingly high risk of transmission facilities supplying downtown Toronto becoming overloaded during heavy demand periods and a combination of new generation capacity, demand-side initiatives and transmission are needed to alleviate this concern. The present transmission facilities are already operated at or near their capacity during hot summer days when electricity demand is high due to the heavy use of air conditioning. As electricity demands continue to grow faster than new transmission can be built, it is vitally important for generation to be located in the downtown area within the next two to three years in order to reduce power flows through heavily loaded transmission facilities to acceptable levels.

In the absence of additional generation as well as demand-side initiatives, it is expected that emergency rotational power outages would be required in order to prevent the overloading of transmission facilities.

The immediate risk that power outages will be necessary in Toronto can be avoided for a number of years by locating additional generation in the area. However, over time, this risk will again grow to unacceptable levels as electricity demand in downtown Toronto continues to grow, and new transmission, or more generation, must be built to provide more supply capability to downtown Toronto. Hydro One has proposed two alternative transmission projects to address this need – a Direct Current (DC) Option and an Alternating Current (AC) Option. Both options meet IESO criteria and improve the reliability of supply to downtown Toronto. However, the DC option is preferred as it requires fewer other transmission system upgrades and provides desirable geographic diversity.

Supply to Western Greater Toronto Area (GTA)

The 2004 10-Year Outlook indicated that additional generation capacity or demand-side initiatives were required in the western GTA to replace generation previously supplied by the Lakeview coal-fired station, and to thereby alleviate the risk of auto-transformer overloading.

The recently completed phases of the Parkway Transformer Station in Markham, the extension of an existing 230 kV double circuit line between Richmond Hill and Markham, and the installation of new transmission equipment in a number of stations within the GTA have provided necessary short-term relief.

Several successful RFP projects are located within the western GTA, to be brought into service between Fall 2005 and Summer 2009. However, these projects are not sufficient to address the growing problem. The need for additional supply in this area is still urgently required. The government’s plan includes procurement of an additional 1,000 MW to meet this need.

Location

The location of replacement generation is important to maintaining the capability of the Ontario power system. Reactive power support in critical locations is needed in order to maintain adequate voltages throughout the system, particularly in the Greater Toronto, Golden Horseshoe and the Kitchener-Waterloo-Guelph areas where a significant portion of the load is concentrated. Without voltage support, the ability of the system to transfer energy would be reduced and the ability to supply energy to loads would be lessened. Nanticoke Generating Station is particularly important in this regard. The replacement of the Nanticoke Generating Station is the most complex aspect of the coal-phase out – but can be achieved provided the replacement supply and infrastructure additions of the plan are built.

Ontario’s ability to import and export energy is an essential element of secure and reliable interconnected system operation, and provides large financial benefits to Ontario market participants and ratepayers. The ability to import and export energy is dependent on where replacement supply is located.

The capability of the Ontario power system can only be maintained with the addition of replacement capacity in the right amounts in the most effective locations. Generation investment in the right locations will take advantage of existing transmission lines and facilitate the continued operation of the remaining non-coal generation.

The generation and demand response which has been selected under the Clean Energy Supply RFP, and the additional generation procurement identified for downtown Toronto and western GTA meet these requirements. This replacement generation has been identified to resolve developing reliability risks and to maximize the benefits of existing transmission. Locating generation in undesirable locations could require substantial (and difficult) transmission investments, strand existing transmission assets and generation investments, and increase risks to the adequacy and reliability of electricity supply to the province.

Energy Capability

In 2004, 7,500 MW of coal-fired generation supplied 26.8 terawatt-hours (TWh) of energy, or about 17 per cent of the total Ontario energy demand, at an average capacity factor of about 40 per cent. Although the energy characteristics of individual replacement generating facilities may differ from existing coal-fired generating stations, the aggregate of the new replacement resources must closely resemble the overall energy capability of existing coal-fired generating stations to ensure that energy is available to serve load with the same level of reliability.

Flexibility for Load Following

Coal-fired generators currently play an important role in responding to load changes that occur during five-minute intervals throughout the day. The largest load change typically occurs during the morning pick-up period, and is about 60 to 70 MW per minute, at times totalling more than 3,000 MW an hour, with periods of sustained increase or decrease lasting for up to four hours or more. Experience to date indicates that existing Ontario gas-fired generators typically offer load following capability over the upper 25 per cent of their capacity range, whereas coal-fired units can typically achieve load following from minimum load up to maximum output, which represents the upper 80 per cent of each unit's capacity range. Although nuclear units can ramp down and off the system rapidly, existing units are restricted from varying their output up and down for the purposes of load following. Having sufficient load-following capability is essential to reliability, and the mix of replacement generators will need to have sufficient load following capability to meet system needs.

Capability of Replacement Resources to Provide Operating Reserve

The ability to maintain sufficient operating reserve is critical to system reliability, and the IESO is required by the Northeast Power Co-ordinating Council (NPCC) to maintain Operating Reserve in accordance with established criteria. Operating Reserve is required for unexpected system events such as random forced outages of generation or transmission equipment, unexpected increases in load, and uncertainty associated with the performance of generation facilities or dispatchable loads in responding to IESO dispatch instructions.

Generation and demand response resources providing Operating Reserve must be capable of responding to the IESO's request to increase generation or decrease consumption within 10 or 30 minutes. Coal-fired generation has typically been an important source of operating reserve, and replacement generation will need to have similar capability. The mix of resources brought in service must be capable of continuing to meet system needs for operating reserve.

System Transition Risk Mitigation

The transition from coal to clean replacement supply is an extremely challenging objective. In terms of the amount of coal generation to be replaced, an amount of clean supply larger than all of the hydroelectric capacity in Ontario must be arranged for, constructed, commissioned and reach a reliable state of operation.

This transition must take place without jeopardizing electricity reliability and within the capabilities of the industry to deliver. Managing a challenging objective such as this requires planning, monitoring and adjustment of schedules and plans to ensure that reliability is maintained and the transition proceeds efficiently. The IESO will monitor and assess the coal shutdown and replacement resource plans and will provide advice to all parties regarding the actions or adjustments required to ensure reliability is maintained.

Located in Haldimand County, the Nanticoke coal-fired generating station can supply almost 4,000 MW of capacity – enough to meet approximately 20 per cent of Ontario's peak demand on a spring or fall day. The shutdown of the station is particularly complex due to a number of factors, including the growing demand for power in the GTA. Nanticoke also provides reactive power to support the heavy power flows from those areas to the GTA .

Supply to the GTA remains a critical concern. Current GTA demand is about 10,000 MW or 40% of Ontario's total demand and is expected to increase by approximately 1,500 MW in the next decade. This is compounded by a lack of generation within the area to supply the forecasted increase in demand.

As a result, and until additional sources of supply or demand-side initiatives become available within the GTA, the load must be supplied by generation outside the area. The

Nanticoke station provides both energy and capacity to help supply the GTA in addition to providing reactive power to support the transfer of power from southern Ontario supply located some distance from the GTA.

Under peak load conditions, a minimum of six Nanticoke units are currently required to be in service to ensure reliable system operation. Without these units, reductions in the output from the Bruce nuclear stations would be necessary. In the event that all units at Nanticoke are shutdown, and equivalent replacement voltage support is not available, the allowable output from the Bruce stations would be significantly restricted and the feasibility of returning Units 1 & 2 to service would be jeopardized.

The flow eastward on transmission lines into Toronto could also be restricted by substantial amounts, depending on the availability of Nanticoke generation or equivalent replacement generation sources. The permissible flow eastward on the transmission lines from south western Ontario can be reduced about 1,000 MW in the absence of any Nanticoke units. This could require the operation of other more expensive generation east of this interface and, under peak load conditions, could result in load interruptions in the Toronto area.

Reactive power and voltage control capability cannot be supplied over long distances. These capabilities will continue to be required locally from Nanticoke until it can be replaced, either at Nanticoke, from generation located within the major load centres such as the GTA, or by other system developments that reduce the need for reactive power and voltage control at Nanticoke.

The IESO is proposing that several units at Nanticoke be converted to operate as synchronous condensers which would produce reactive power to support the transfer of energy produced by Bruce. The final number required will be dependent on a variety of other infrastructure decisions.

Plan Highlights

Ontario benefits from a variety of electricity sources. Each fuel type fulfills a different role in meeting Ontario's power needs, which must be taken into account in planning the system.

There are many factors that are important considerations in the redevelopment of Ontario's electricity infrastructure, some of which could cause the long-term supply-demand balance to change. On the supply side, failure to meet the requirements discussed in this section would tend to reduce the operable generation from that assumed in the 10-Year Outlook.

New Generation Mix

A diverse generation mix is critical for resource adequacy and market efficiency, through the provision of dispatch flexibility, reduced vulnerability to fuel supply contingencies and fuel price fluctuations.

Baseload Generation

Baseload generation largely consists of nuclear and run-of-the-river hydroelectric resources which cannot routinely be cycled on and off in response to demand fluctuations. In the future, significant additions of gas-fired cogeneration are also expected to contribute to baseload generation. These types of generators have limited dispatch flexibility, and must operate at or near their full capability. If too much baseload generation is present in the supply mix, the amount of generation can have the potential to exceed the market demand, creating a situation known as unutilized baseload generation (UBG). An analysis of the minimum peak demands in the latter years of the study period suggests that up to approximately 4,000 MW of nuclear and run-of-the-river generation resources could be added to the existing in service baseload facilities towards the end of the ten-year period without causing undue risk of UBG. This amount will be affected by load growth and any load shifting patterns between on-peak periods and off-peak periods.

Intermediate and Peaking Generation

Existing intermediate and peaking generation in Ontario consists mainly of generation fuelled by coal, some gas, oil, and those hydroelectric generators with storage capability. New intermediate and peaking generation must be added to the Ontario resource mix in order to implement the coal replacement plan.

Renewable Generation Resources

Renewable resources consist primarily of hydroelectric, wind, biomass, solar, and geothermal energy sources. These are considered the cleanest and least environmentally impactive of all generation resources. Only wind and a small amount of hydroelectric generation have been contracted under the government's RFPs for connection to the IESO-controlled grid (ICG). Further utilization of wind energy can be achieved through partnering with suitable hydroelectric facilities to co-optimize both types of resources.

Conservation and Demand-Side Measures

The IESO has been identifying the potential contribution of conservation and demand-side measures (CDM) as part of the supply picture for several years and believes demand reductions and demand shifting should be vigorously pursued in Ontario, as clean and potentially less expensive ways to reduce future supply requirements. The application of such demand-side initiatives is virtually unrestricted in location.

CDM programs would improve the supply-demand balance in three main ways:

- Price-responsive demand which reacts to market price signals;
- Demand reduction through technological or process efficiency improvements; and
- Shifting the time of use from peak to off-peak periods through demand-response
- programs would achieve peak demand reductions.

The Conservation Bureau of the OPA has been charged with leading development of conservation and demand-side measures. The provincial government has targeted a 5 per cent demand reduction by 2007 through CDM developments, or approximately 1,350 MW.

The system requires more reactive resources during the summer than the winter for the same level of demand. Air-conditioning load is the most significant component of the higher reactive power demand in the summer than in the winter. The IESO recommends that Ontario work with other jurisdictions to raise the power factor requirements of new air-conditioning equipment. This would, in the long term, reduce the need for generation and transmission enhancements to meet the active power demand in Ontario. A move to energy-efficient appliances has already been encouraged by government programs within Ontario and in other jurisdictions; however, most of these programs have focused on reductions to active (real) power consumption.

Interconnections

In real-time system operation, reliance on external supply through interconnections is mutually beneficial to all interconnected systems, for both reliability and market efficiency reasons. During off-peak periods, attractively priced external supply can provide cost savings to the electricity market. Similarly the interconnections provide access to broader markets for inexpensive Ontario generators. During peak hours, due mainly to the non-coincidence of the peak demands with one or more neighbouring systems, external supply can contribute to meeting peak demand.

Two main aspects are relevant to utilization of interconnection benefits: transmission interconnection capability and external supply availability.

Interconnection Capability

Ontario has a maximum coincident import capability of approximately 4,000 MW through its existing interconnections. Transmission projects have been identified to the IESO through the Connections Assessment and Approval process to enhance the interconnection capability. A high voltage direct current (HVDC) interconnection with Hydro Quebec of 1,250 MW transfer capability would allow increased interchanges between Ontario and Quebec. At this time, this has high project uncertainty. A joint proposal to receive power from the Lower Churchill Falls area could provide incentive for completion of the development of the proposed HVDC tie with Hydro Quebec.

Although not yet formally submitted for Connection Assessment, an upgrade to the Ontario - Manitoba interconnection would give access to hydroelectric capacity from Manitoba.

External Supply Availability

Future levels of imports into Ontario will vary depending on several factors, including the availability and economic benefits associated with resources in external jurisdictions capable of supplying the Ontario market, and the availability of required transmission capacity.

Generation Flexibility

The IESO is concerned with the future management of the province's water resources as they relate to electricity production. The flexibility available in the operation of hydroelectric facilities is of value to the Ontario power system. The importance of this needs to continue to be reflected and balanced with other uses which may influence provincial requirements with respect to water management.

Ontario's electricity consumption pattern has changed over the last decade. Consumers have historically used more electricity in the winter than they did in the summer. This has reversed. Peak electricity demands now occur during the summer, the season in which water management is typically most restricted.

Within a typical day, the total hydroelectric energy production pattern follows the shape of the total Ontario electricity demand. This flexibility of hydroelectric generation is significant; these plants can store potential energy when it is needed least (e.g., overnight) and can deliver their energy very quickly when it is needed (e.g., during morning load pickup when Ontario consumers increase their electricity use, at times greater than 3,000 MW per hour). Similar benefit exists from managing the water for electricity production on a weekly and seasonal basis.

The flexibility of hydroelectric generation has always been of value but its importance will increase even more in the future. Coal-fired generation, while not as flexible, currently provides an important capability to meet load pick up and drop out requirements. That capability may be reduced when the coal plants shut down. Conservation, while reducing overall requirements, will not likely change the load pick-up requirement. Much of the renewable generation is expected to be wind power which has many positive features but cannot effectively be ramped up or down to meet changes in demand. Demand management is likely to help reduce peak demands but is not likely to affect ramping requirements. Gas-fired generation will have the required flexibility but even it can be limited if the plant is an efficient cogeneration facility. Given the expected future mix of resources in Ontario, the value of hydroelectric flexibility will increase.

In addition to providing energy and ramping capability, the flexibility of waterpower makes it extremely valuable for two other essential reliability products; operating reserve and automatic generation control.

- The provincial demand for electricity varies second to second, sometimes by surprisingly large amounts. Hydroelectric generation is used very effectively to continuously keep this varying demand and supply in balance, and to keep Ontario's trade with other states and provinces on schedule. Historically in Ontario, very short-time balancing "automatic generation control" has been provided by a small number of hydroelectric plants. Restrictions on the allowable limits within which hydroelectric facilities operate would require extending the use of automatic generation control to more market participant generators.
- Ontario's future generation supply mix will place an increasing reliability value on the flexibility of generating assets to provide load following capability, operating reserve and automatic generation control. Preserving operating flexibility of hydro-

electric generating facilities (whether old or new) should be a critical consideration in the development of water management plans.

With the awarding of contracts to several wind proponents, exceeding 350 MW in total with more expected from the second Renewable RFP, it will not be long before significant amounts of wind generation are contributing to the energy needs of the province.

Early studies indicate wind should make significant contributions to energy but there is less certainty with respect to the peak-meeting capacity contribution that wind will make. Wind capacity is only available when the wind blows. During winter periods, a relatively strong coincidence of wind output and peak demand is expected, especially since wind chill drives heating demand higher. However during summer periods, peak demands typically occur during hot periods with little wind, the type of weather which pushes air conditioning loads to their maximum. The reduced contribution from wind during these periods increases the power system's reliance on alternative supplies of capacity.

The geographic diversity of projects around the province should provide some stability to wind output and reduce the impact of local wind fluctuations. Assessing the connection of wind generation has needed careful examination with respect to aspects such as a facility's ability to stay connected during low voltage excursions, its ability to supply reactive power, data monitoring requirements, and others. Notwithstanding these considerations, the presence of wind on the Ontario grid will be a positive contribution to Ontario's future supply mix. For the purposes of this study, it is assumed 10 per cent of the installed capacity of wind powered generation can be relied on at the time of the annual peak.

Summary of Transmission Enhancements Identified in the IESO's 10-Year Outlook

The following table summarizes all the key transmission enhancements the IESO recommends for installation across the province to provide necessary IESO-controlled grid reliability.

Table 1: Summary of Transmission Enhancements Identified in the IESO 10-Year Outlook

Summary of Transmission Enhancements Identified in the IESO 2005 10-Year Outlook		Need date	Comments	Diagram No.
Facilities required to accommodate the planned shutdown of Nanticoke GS and the return to service of Bruce A units 1 and 2				
1	Series Capacitors in the following 500kV circuits associated with the Bruce Complex: Circuits B562L & B563L between Bruce GS & Longwood TS Circuits B560V & B561M between Bruce GS & Claireville TS/Milton TS Circuit N582L between Longwood TS & Nanticoke GS	Spring-2008	Scheduled for the spring-2009 & the fall-2009, respectively	6
2	Shunt Capacitors at Middleport TS (nominally rated at between 400MVAr & 500MVAr)	Spring-2008		
3	Conversion of two (or more) generating units at Nanticoke GS to synchronous condenser operation.	Spring-2009		

	Summary of Transmission Enhancements Identified in the IESO 2005 10-Year Outlook	Need date	Comments	Diagram No.
4	Installation of a 230 kV connection into Cambridge-Preston TS from a new 500/230 kV TS established on the right-of-way of the existing 500kV double-circuit line, M585M & V586M, between Nanticoke GS & Claireville TS/Milton TS. This work would also include the installation of two 230/115kV auto-transformers at Cambridge-Preston TS to provide a connection to the local 115kV system between Detweiler TS and Guelph-Cedar TS.	Spring-2008	To improve voltages and increase the supply capability in the Kitchener, Waterloo, Cambridge, Guelph & Orangeville area. This work is also required to ensure that adequate post-contingency voltages can be maintained following the loss of the Bruce-to-Milton 500kV line.	5
5	Installation of a new 500/230 kV TS at Bellwood Junction, where the existing 500kV (circuits B560V & B561M) & 230 kV (circuits D6V & D7V) rights-of-way intersect.	Spring-2008		
6	Although not a transmission enhancement, the installation of the planned 1,500 MW of additional generating capacity in downtown Toronto & the western GTA is also crucial to the plan to shutdown Nanticoke GS.	Fall-2008	These facilities are required to ensure that adequate post-contingency voltages can be maintained in the GTA following the loss of the Bruce-to-Milton 500kV line.	
Facilities required to accommodate the planned shutdown of Lambton GS				
7	Reconfigure the termination of the existing 230 kV circuits at Lambton TS to allow the busbar to be operated split and respect the fault interrupting capacity of the existing breakers	Fall-2007	To accommodate the commissioning of the new generating facilities in the Sarnia area while the existing units at Lambton GS are still operational.	
Facilities required to address the issues related to the supply to downtown Toronto				
8	Completion of the John-to-Esplanade Link	Fall-2007	This will defer the need date for supply in the Leaside Sector by two-years: to 2010 with weather-corrected loads & 2008 with extreme-weather loads	4
9	Incorporation of 500 MW of generation capacity into the Hearn 115kV busbar	Spring-2008	The need date for this facility is governed by the planned shutdown of Nanticoke GS. This facility will defer the need date for the 3rd Supply to 2012 (with weather-corrected loads) & 2010 (with extreme-weather loads).	

	Summary of Transmission Enhancements Identified in the IESO 2005 10-Year Outlook	Need date	Comments	Diagram No.
10	Incorporation of 1000 MW of generation capacity within the western GTA	Fall-2008	The need date for this facility is governed by both the planned shutdown of Nanticoke GS and the requirement to support transfers from the Leaside Sector to the Manby Sector, via the John-to-Esplanade Link.	
11	Extension of the John-to-Esplanade Link to Hearn	Spring-2008	This will address the requirements to perform maintenance on the existing facilities in the Manby West TS.	
12	3rd Supply to Downtown Toronto	Spring-2010	To secure the supply for extreme-weather loads.	
		Spring-2012	To secure the supply for weather-corrected loads.	
Facilities required to accommodate the planned shutdown of Atikokan GS				
13	Install shunt capacitors at Fort Frances or Mackenzie TS.	Before 2007	To offset the reactive capability removed from the system with Atikokan retirement.	
Facilities required to address existing or emerging system issues				
14	Series Capacitors at Nobel SS in the 500kV circuits X503E & X504E, between Hanmer TS & Essa TS.	Existing	To address the worsening congestion situation on the north-south corridor.	7
15	Installation of two 500/230 kV auto-transformers at Milton TS and the extension of the existing double-circuit line from Meadowvale TS through to Cardiff TS via a new 230 kV switching station on the right-of-way of the existing double-circuit line (R19T & R21T) supplying Pleasant TS.	Spring-2008	To relieve the 500/230 kV auto-transformers at Trafalgar TS and also improve supply reliability to Georgetown, north Oakville, north Mississauga & Brampton.	2
16	Installation of a 230/115kV auto-transformer at Kent TS.	Immediate	To improve supply reliability to the Windsor area & avoid supply interruptions in the event of equipment failures.	8
17	Uprating of the 115kV circuits J3E & J4E between Keith TS and Essex TS and the replacement of the existing auto-transformers at Keith TS with higher-rated units.			
18	Construction of a new 230 kV connection between Keith TS and Lauzon TS.	Immediate		
19	Increase the transfer capability of J5D conductor to better match the phase-shifter regulating transformer rating.	Not determined	To increase import capability by at least 200 MW.	

<table>
<tr><th colspan="3">Summary of Transmission Enhancements Identified in the IESO 2005 10-Year Outlook</th><th>Need date</th><th>Comments</th><th>Diagram No.</th></tr>
<tr><td>20</td><td colspan="2">Installation of a new 500/230 kV TS in the vicinity of the intersection of the Bowmanville TS to Lennox GS 500kV corridor and the 230 kV right-of-way of the circuits supplying Belleville TS</td><td>Not determined</td><td rowspan="2">To enhance the load meeting capability of the existing facilities to accommodate the growth demand in the Oshawa and Belleville areas.</td><td rowspan="2">9</td></tr>
<tr><td>21</td><td colspan="2">Construction of a new double-circuit 230 kV line from Cherrywood TS into the Oshawa area
OR
The installation of a new 500/230 kV TS at a suitable location east of Wilson Junction along the 500/230 kV corridor between Cherrywood TS and Bowmanville TS.</td><td>Not determined</td></tr>
<tr><td>22</td><td colspan="2">Replacement of the two 215MVA 230/115kV auto-transformers at Burlington TS with higher-rated units</td><td>Immediate</td><td>To avoid supply interruptions</td><td></td></tr>
<tr><td rowspan="2">23</td><td rowspan="2">Reinforcement of the Queenston Flow West (QFW) Interface</td><td>230 kV reinforcement between Allanburg TS & Middleport TS</td><td>Fall-2007</td><td rowspan="2">Identified in IESO’s 2004 10-year Outlook</td><td></td></tr>
<tr><td>Uprating of the existing 230 kV circuits into Burlington TS</td><td>Immediate</td><td></td></tr>
<tr><td>24</td><td colspan="2">Implementation of measures within the Ottawa area to address voltage decline issues</td><td>Not determined</td><td></td><td></td></tr>
<tr><td>25</td><td colspan="2">Enhance reactor switching and P502X special protection system in north-east.</td><td>Immediate</td><td>To increase the generation and load rejection arming threshold and improve the reliability to northeast 115 kV system.</td><td></td></tr>
<tr><td colspan="6">Facilities required to accommodate the expansion of the Mattagami River Plants</td></tr>
<tr><td>26</td><td colspan="2">Installation of series capacitors in the 500kV circuits north of Hanmer TS, together with the installation of shunt capacitor banks at Little Long GS & Hanmer TS, should a decision be made to proceed with the expansion of the Mattagami River Plants.</td><td>To suit schedule</td><td></td><td>7</td></tr>
</table>

Notes:
The exact requirements for Items 2 and 3 are to be determined as part of the IESO's assessment of the proposal to install series capacitors in the 500kV circuits associated with the Bruce Complex.
All the items in the table above have been identified in Hydro One’s 10 Year Plan or are included in a Connection Assessment and Approval application with the exception if items 2,3,13,15,18, and 26.

ISO-NE

Note: The information provided for ISO New England is based on the ISO-NE board-approved 2005 Regional System Plan (RSP05).

a. Summary of Most Recent Plans

This summary highlights the major results of the ISO New England's 2005 plan for the future development of the bulk power system.

RSP05 identifies system improvements needed over the next 10 years and provides information on what infrastructure improvements are needed and when and where they are needed to meet the system's peak demands in conformance with planning criteria. Plans for the region's future electricity infrastructure must account for the uncertainty of assumptions over the next 10 years in terms of load growth, fuel prices, new technology, market changes, environmental requirements, and other relevant events.

As with previous planning reports (Regional Transmission Expansion Plans), RSP05 provides technical information and data on various scenarios and identifies the requirements for maintaining, improving, and ensuring the reliability of the system in the short term. The plan also assists in linking physical system needs to wholesale market mechanisms aimed at attracting market solutions (generation, demand response, etc.) to mitigate these needs. RSP05 thus is a broader plan of the region's electricity system needs than the previous RTEP reports.

RSP05 resource adequacy studies are consistent with previous RTEP findings that indicated the need for significant new generation or demand-side resources in New England in the 2008 to 2010 timeframe. Key findings of RSP05 are as follows:

- RSP05 identifies 272 transmission projects required for the reliability of the New England system. Previous RTEP reports emphasized the major 345 kV projects. RSP05 reinforces the need for the major 345 kV projects and places greater emphasis on the need for transmission projects throughout the system and particularly within load pockets. ISO-NE estimates these projects to cost between $2.0 and 4.0 billion dollars, collectively.

- Under high-demand conditions, New England will more likely be forced to operate under emergency conditions as soon as 2006 due to resource limitations in the Connecticut (CT), Southwest Connecticut (SWCT), and Norwalk/Stamford Subareas (NOR).[14]

[14] To conduct resource planning reliability studies within New England, the region is modeled as 13 subareas and three neighboring control areas. In addition to SWCT, NOR, and CT, these subareas include northeastern Maine (BHE); western and central Maine/Saco Valley, New Hampshire (ME); southeastern Maine (SME); northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine (NH); Vermont/southwestern New Hampshire (VT); Greater Boston, including the North Shore (BOSTON); central Massachusetts/northeastern Massachusetts (CMA/NEMA); western Massachusetts (WMA); southeastern Massachusetts/Newport, Rhode Island (SEMA); and Rhode Island bordering Massachusetts (RI). Greater Connecticut includes the CT, SWCT, and NOR Subareas. Greater Southwest Connecticut is comprised of the SWCT and NOR Subareas. The three neighboring control areas are New York, Hydro-Québec, and the Maritimes.

- From a system-wide perspective, installed capacity projections show that additional resources are needed to meet system-wide demand as early as 2008 but no later than 2010.

- Analysis of operating reserves shows the immediate need for approximately 1,100 megawatts (MW) of incremental quick-start resources or units with competitive energy prices in BOSTON and Greater Connecticut, especially in Greater Southwest Connecticut.[15] Adding 530 MW (of the 1,070 MW) in Greater Connecticut will meet this area's capacity needs and also serve to meet system-wide needs.

- The region must convert 400 MW of gas-fired generation to dual-fuel capability (i.e., having the flexibility and storage capacity to use oil as well as gas) by winter 2006/2007 and increase that capability by 250 MW per year through winter 2008/2009 and 500 MW more in winter 2009/2010.

b. Planning Issues

The planning issues for ISO New England relate to resource adequacy and transmission.

Resource Adequacy

Three planning issues for resource adequacy are timing and amount of resource need, the preference for quick-start resources, and fuel diversity.

ISO's planning has used two methods to determine the timing and amount of resource need. The traditional method (i.e., installed capacity) based on the probabilistic LOLE methodology, shows the need is 170 MW in 2010. The second method, referred to as operable capacity, is a scenario analysis of possible deterministic operating conditions. It shows the need beginning in 2008 at a minimum of 160 MW and possibly reaching up to 1,900 MW for extreme weather peak loads. ISO New England will further explore the alignment of these two methods and their relationship to LICAP.

Quick-start resources typically can be brought on-line at full capacity within 10 minutes. These resources are needed in sufficient amounts in specific load pockets to assure reliability is maintained in those pockets during sudden generation or transmission outages. These resources can consist of demand-response programs or quick-start capacity, such as combustion turbines or pumped storage.

With New England's rapid growth since 1999 of gas-fired combined-cycle generation capacity, the system's fuel diversity has became an issue, as the region now is highly dependant on natural gas as a fuel source. This issue became important during the January 2004 Winter cold snap when much of this gas capacity was unavailable for various reasons.

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[15] Quick-start capacity is typically comprised of pumped storage and conventional hydro units, combustion turbines, many load-response (i.e., load-reduction) program resources, and internal combustion units that can start up and be at full load in less than 30 minutes. These units provide greater operating flexibility in daily operations and in emergency situations than base-load generators, which are available at all times to serve load, or generators that are available to serve intermediate load levels. In daily operations, quick-start resources can help replenish the capacity lost due to a sudden and unexpected loss of a generating unit or transmission facility. Under severe peak-load conditions, quick-start units can help avoid the need to implement involuntary load shedding by providing either energy or operating reserves.

The need to add dual-fuel capacity to the region's "gas-only" plants is critical to provide fuel flexibility in cold-snap conditions in the future. To increase fuel diversity for the longer term, the region needs to emphasize generation additions that do not depend solely on natural gas (e.g., renewable resources).

Transmission

The nature of the New England transmission system has led to a number of voltage-performance issues. Transmission lines that connect distant resources, limited transformation (i.e., from step-down transformers), and heavy transfers near the physical system's capability, create the potential for voltage collapse. In many instances, fixed capacitors have been installed and are sufficient to address these problems. However, capacitors have limited applications because the amount of voltage support they provide decreases as the square of the voltage (V^2) decreases. Thus, capacitors provide less voltage support at the very time they are needed the most—as voltages become very low.

The system will increasingly require fast-response dynamic voltage-control devices to allow voltage recovery after contingencies while preventing excess voltages before the contingencies. These devices also provide continuous voltage support and improved voltage regulation. Some of the devices that provide dynamic and continuous voltage support are static compensators (STATCOMs) and static VAR compensators (SVCs). These devices use power electronics that can adjust power and voltage output almost instantaneously.

Another emerging voltage-control technology not yet employed involves the installation of "clutch devices" on generators. These devices would allow a synchronous generator (i.e., a typical type of generator connected to the network) to be disengaged from its prime mover—the motive force that drives the electricity generator, such as a water or steam turbine—and be operated as a voltage-regulating synchronous condenser.[16] Reactive compensation to improve voltage support has limitations, however. Many studies have identified locations where reactive compensation already has been maximized, such as in northwestern Vermont. The only way to improve these areas is to add new transmission facilities.

c. Statistics

The figure below provides some basic statistics about New England's electric bulk power system and the wholesale energy markets.

[16] Generation owners interested in such opportunities should contact ISO New England to discuss potential locations for such conversions.

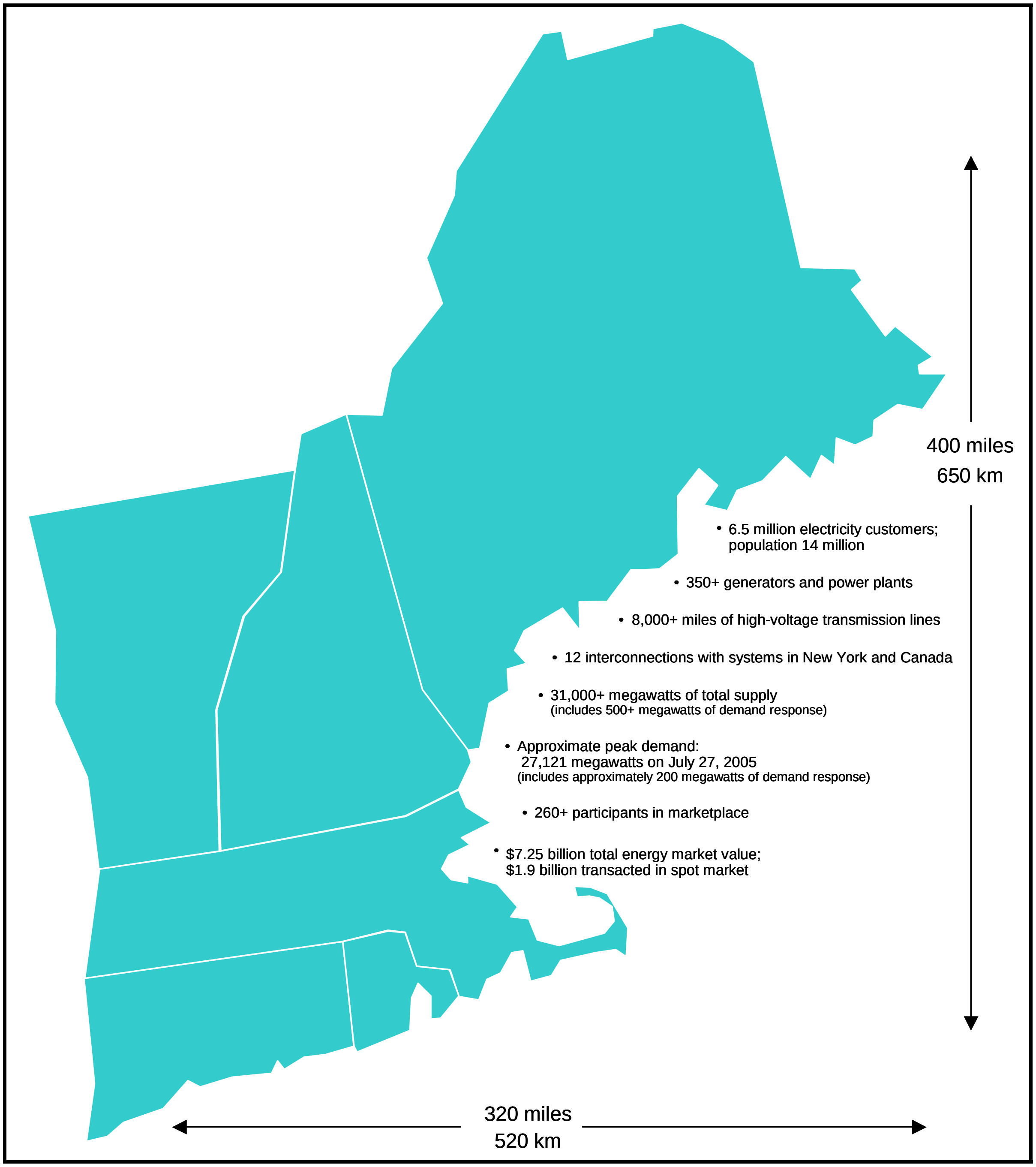


Figure 1: Key facts on New England's Electric Power System and Wholesale Electricity Market

i. Load Growth

The table below provides ISO New England's projections for energy growth and summer and winter peak loads for the next 10-year period. The peak loads are given for a normal peak weather case with a 50/50 probability of being lower or higher than the value shown, and a more extreme weather case (i.e., a 90/10 probability). New England is a summer-peaking system so the summer peak loads are higher than the winter peak loads. Energy is projected to grow at 1.4% per year, with the summer and winter peaks growing at 1.5% per year.

Table 1: Energy and Peak-Load Forecast Summary for the ISO New England Control Area and States, Net Energy for Load (GWh)

Area	Net Energy for Load (GWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50		90/10		CAGR	50/50		90/10		CAGR
	2005	2014	CAGR	2005	2014	2005	2014		2005/06	2014/15	2005/06	2014/15	
NE Control Area	134,085	152,505	1.4	26,355	30,180	27,985	32,050	1.5	22,830	26,005	23,740	27,030	1.5
CT	34,620	40,500	1.8	7,125	8,305	7,580	8,835	1.7	6,025	6,990	6,285	7,290	1.7
ME	12,140	13,790	1.4	1,975	2,255	2,060	2,355	1.5	1,960	2,220	2,010	2,270	1.4
MA	60,590	67,430	1.2	12,110	13,660	12,845	14,485	1.3	10,340	11,600	10,780	12,080	1.3
NH	11,840	13,990	1.9	2,300	2,720	2,490	2,950	1.9	2,040	2,400	2,125	2,500	1.8
RI	8,525	9,760	1.5	1,805	2,075	1,920	2,205	1.6	1,435	1,660	1,490	1,720	1.6
VT	6,375	7,035	1.1	1,045	1,175	1,100	1,235	1.3	1,030	1,150	1,060	1,180	1.2

ii. Interconnection Queue

The table below shows the current generation capacity in the ISO New England Interconnection Queue undergoing System Impact Studies. About two-thirds of the capacity in the queue is proposed to be fueled by natural gas. The “18.4/I.3.9” category reflects the projects approved for interconnection with the transmission grid.[17]

Table 2: Proposed Generation Projects by Type

Fuel/Energy Source	In System Impact Study Queue (MW)	With 18.4/I.3.9 Approval (MW)
Gas primary	2,004.8	1,447.3
Oil	96.0	6.0
Wind onshore	264.5	71.5
Wind offshore	425.0	0.0
Biomass	56.0	16.0
Hydro	0.0	0.0
Nuclear uprates	260.0	260.0
TOTAL	**3,106.3**	**1,800.8**

iii. Transmission Build

The table below summarizes the current 272 transmission projects, both planned and proposed, over the next 10 years (2005 to 2014) to be built in New England. The total costs of these projects are estimated to be between $2 and 4 billion dollars. Six “big” projects account for about two-thirds of the cost of all the 272 projects. The 272 projects

[17] Prior to 2005, ISO-NE projects received “Section 18.4”approval, which refers to the section in the *First Restated NEPOOL Agreement*. This agreement was replaced by the ISO-NE’s 2005 tariff. See the *Second Restated NEPOOL Agreement* at: <http://www.iso-ne.com/regulatory/restatd_nepool_agree/index.html>.

are the result of the ongoing planning assessments by ISO New England and the seven transmission owners that serve the region.

The 272 projects include transmission improvements in load/generation pockets required to reliably serve load and to reduce dependencies on the need to commit generating units for operating reserves, voltage support, and the relief of other transmission constraints. These transmission improvements also will reduce operating-reserve costs. The load/generation pockets discussed in RSP05 include Middletown (CT); Norwalk–Stamford (CT); Southwest Connecticut; Springfield (MA); Boston; and the North Shore (MA).

Table 3: Cost Comparison of Reliability Projects October 2004 vs. July 2005

Major 345 kV Projects	As of October '04 Plan Update (in millions $)	As of July '05 Plan Update (in millions $)	Change in Plan Estimate (in millions $)	Reasons for Change
Northwest Vermont Reliability Project	156.3	156.3	0	
Southwest Connecticut Reliability Project (Phase I)	200.0	357.0	157.0	Re-evaluation of costs based on actual bids, one-year delay in in-service date, inflation, environmental mitigation, and higher exchange rates and copper prices (cables)
Southwest Connecticut Reliability Project (Phase II)	690.0	990.0	300.0	Re-evaluation of engineering cost estimates, two-year delay in in-service date, inflation, environmental mitigation, higher exchange rates (cables), and design and scope modifications resulting from CSC review.
NSTAR 345 kV Transmission Reliability Project	217.0	234.2	17.2	Cable work related to New Boston
Southern New England Reinforcement Project	125.0	125.0	0.0	
Northeast Reliability Interconnect Project	90.4	90.4	0.0	
Subtotal	**1,478.7**	**1,952.9**	**474.2**	
Other Projects	824.2	1,009.6	185.4	Various
New Projects	0.0	79.9	79.9	
TBD Projects with cost estimates	0.0	197.1	197.1	First estimates reported for projects
Total	**2,302.9**	**3,239.5**	**936.6**	
minus 'in-service'	-143.3	-216.8		
(Aggregate estimate of active projects in the Plan)	2,159.6	3,022.7		

Transmission Upgrade Achievements

Most of the transmission projects identified in the RTEP/RSP process are reliability upgrades for ensuring that the region continues to satisfy national and regional reliability standards while continuing to operate in an economical manner. Many of these upgrades will provide the additional benefit of enhancing the efficient operation of the region's power markets in that they will allow access to generating resources external to the load pockets, the repowering or interconnection of generating facilities, and the movement of power to where it is needed.

Because Connecticut and Southwest Connecticut are considered to be critical areas in terms of service reliability, shorter-term system improvements have been implemented in these areas. Coupled with reactive improvements to the distribution system, the following highlights of the completed reliability projects in Connecticut have enhanced both system reliability and market efficiency:

- Elimination of a Long Mountain stuck-breaker contingency that resulted in the loss of three 345 kV lines
- Installation of the Glenbrook static compensator to improve voltage performance in Southwest Connecticut
- Installation of two dynamic Voltage Ampere Reactive (DVAR) systems to improve voltage performance in Southwest Connecticut
- Installation of capacitor banks at strategic locations in Connecticut to further support steady-state voltage conditions
- Replacement of circuit breakers across Connecticut to increase short-circuit duty

These improvements have reinforced the reliability of the Connecticut transmission system in advance of completing the major 345 kV reinforcement projects taking place in New England (see below). Earlier improvements have increased transfer limits into Southwest Connecticut by 300 MW, from 1,700 MW to 2,000 MW. More recent transfer-limit improvements have increased transfer limits into Southwest Connecticut by another 300 MW (up to 2,300 MW) and also Connecticut's ability to import by 100 MW up to 2,300 MW. This improvement helps bring lower-cost energy into each area when available and mitigate the need for out-of-merit commitments for system reliability support. However, these projects have not eliminated the need for major additional system improvements.

Similarly, the NEMA upgrades, placed in service in the 2002–2003 timeframe, improved reliability to the Northeast Massachusetts/Boston load pocket while increasing transfer limits by 300 MW. The recent installation of a reactor in Cambridge helps to improve the VAR control situation in the Cambridge/ Boston area during the lighter-load periods.

The RTEP/RSP process has identified several major 345 kV projects that are critical for supporting a reliable power system in New England into the foreseeable future. Significant progress has been made in siting and constructing five of these projects over the past year, as summarized below:

- NSTAR 345 kV Reliability Project—increases transfer limits into the greater Boston area. The Massachusetts Energy Facilities Siting Board permitted the project in January 2005, and NSTAR has commenced construction. The projected in-service date in June 2006 for the first two cable circuits. The third cable is scheduled for service before summer 2008.
- Northeast Interconnect Project—adds a new 345 kV tie line between New England and New Brunswick to improve import and export limits between the two regions and improve system performance in northern Maine. The Maine Public Utilities Commission permitted the project in July 2005. Other permits remain outstanding, including those based on the commission's review of associated support agreements for the Canadian portion of the new intertie. The projected in-service date for this project is December 2007.
- SWCT Phase 1— improves transfer of power and system performance in southwest Connecticut as the first stage of the major Northeast Utilities/United Illuminating

Company (NU/UI) 345 kV project. The project currently is under construction with a projected in-service date of December 2006.

- SWCT Phase 2—improves transfer of power and system performance in southwest Connecticut as the second stage of the major NU/UI 345 kV project. The Connecticut Siting Council permitted the project in April 2005, and the project currently is in the final design and analysis stage. Its projected in-service date is December 2009.
- Northwest Vermont Reliability Project—improves the Vermont Electric Power Company's (VELCO) 345 kV and 115 kV transmission system for the major load center in northwest Vermont. The Vermont Public Service Board permitted the project in January 2005 and, as part of that approval, ordered several project modifications. VELCO has commenced construction and is conducting final design and analysis of project modifications. The projected in-service dates for individual stages of the project range from May 2006 through October 2007.

In addition to the Connecticut, NEMA/Boston, and major 345 kV line projects, a number of other significant system improvements are being made. Upgrades to the North Shore/Ward Hill (MA) Substation currently are being constructed to work in conjunction with the NSTAR 345 kV project. Two of three 115 kV line upgrades out of Ward Hill Substation have been completed, and the addition of autotransformers is in progress. Other improvements were made to increase the reliability to the Cape Cod load pocket, including the addition of an autotransformer, a new line, and a capacitor bank. The Central Massachusetts Project, which will unload the Sandy Pond Substation transformers, and the Auburn Project, which will upgrade a number of stations and lines in the Auburn–DuPont–Bridgewater area, are also under construction.

To increase the SEMA/RI export capability, independent pole-tripping (IPT) capability was made available on select breakers at West Walpole, West Medway, Millbury, and Sherman Road. To increase the ability to move power within the Norwalk–Stamford and SWCT load pockets, two lines out of Glenbrook Substation were reconductored, and 115 kV cables in the Bridgeport area and the Baird–Congress 115 kV lines were upgraded. Autotransformers were added at Scobie Substation in New Hampshire and at West Rutland Substation in Vermont.

Other projects that are nearing the construction stage or have recently been started include the following:

- Southwest Rhode Island—will increase both reliability and inter-area transfer capability between Rhode Island and Connecticut.
- Y-138—will increase both reliability and inter-area transfer capability between Maine and New Hampshire.
- Monadnock—will eliminate thermal and voltage problems and increase reliability by creating stronger ties between central Massachusetts, southeastern Vermont, and southwestern New Hampshire.
- Vermont Northern Loop—will increase the reliability of the line by looping it through the area, instead of feeding it radially.
- Haddam Substation—will install a 345/115 kV autotransformer in south-central Connecticut, injecting 345 kV into a weak 115 kV system.
- Killingly Substation—will install a 345/115 kV autotransformer in Connecticut, injecting 345 kV into a weak 115 kV system and increasing the transfer limit into Connecticut.

iv. Resource Adequacy

The generation resource adequacy situation in New England is shown in the table below based on the installed capacity method. The results in the table are based on a determination of the resources needed to meet the regional 1-day in-10-year LOLE criterion. This is without regard for transmission constraints within New England and considers uncertainty in the load forecast, generating unit forced outages, and maintenance schedules. Since the benefits of ties to neighboring control areas may be variable, the table shows a range of capacity needs with no tie benefits to 2,000 MW of tie benefits. The year of need ranges from 2006 to 2010, and the capacity need in the first ranges from 173 MW to 690 MW over those years.

Table 4: Cumulative Capacity Needed in New England to Meet One-Day-in-10-Year LOLE (MW)

Year	0 MW Tie Benefits	1,000 MW Tie Benefits	2,000 MW Tie Benefits
2005	0.0	0.0	0.0
2006	172.5	0.0	0.0
2007	690.0	0.0	0.0
2008	1,035.0	0.0	0.0
2009	1,897.5	690.0	0.0
2010	2,415.0	1,207.5	172.5
2011	2,932.5	1,897.5	690.0
2012	3,450.0	2,415.0	1,380.0
2013	3,967.5	2,760.0	1,725.0
2014	4,312.5	3,277.5	2,070.0

The two tables below show the results for New England's resource need based on the operable capacity method for the 50/50 peak-load forecast and the 90/10 peak-load forecast, respectively. These tables show a need in 2008 for 160 MW to 1,900 MW for this range of peak-load forecasts.

Table5: Projected New England Capacity, Summer 2006, 2014 Using 50/50 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
Load (50/50 forecast)	26,970	27,350	27,750	28,145	28,565	29,050	29,500	29,845	30,180
Operating reserves	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Total Requirement	28,670	29,050	29,450	29,845	30,265	30,750	31,200	31,545	31,880
Capacity	31,393	31,393	31,393	31,393	31,386	31,386	31,386	31,386	31,386
Assumed unavailable capacity	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Total Net Capacity	29,293	29,293	29,293	29,293	29,286	29,286	29,286	29,286	29,286
Available Surplus/(Deficiency)	**623**	**243**	**(157)**	**(552)**	**(979)**	**(1,464)**	**(1,914)**	**(2,259)**	**(2,594)**

Table 6: Projected New England Capacity Situation, Summer 2006–2014, Using 90/10 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
Load (90/10 forecast)	28,660	29,070	29,495	29,910	30,350	30,860	31,330	31,700	32,050
Operating reserves	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Total Requirement	30,360	30,770	31,195	31,610	32,050	32,560	33,030	33,400	33,750
Capacity	31,393	31,393	31,393	31,393	31,386	31,386	31,386	31,386	31,386
Assumed unavailable capacity	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Total Net Capacity	29,293	29,293	29,293	29,293	29,286	29,286	29,286	29,286	29,286
Available Surplus/(Deficiency)	(1,067)	(1,477)	(1,902)	(2,317)	(2,764)	(3,274)	(3,744)	(4,114)	(4,464)

Midwest ISO

a. Summary of Most Recent Plans

The Midwest ISO Board of Directors has approved two Midwest ISO Transmission Expansion Plans (MTEP). These plans are MTEP 03, approved in June 2003, and MTEP 05 approved in June 05. MTEP reports are available on the Midwest ISO web site at http://www.midwestiso.org/plan_inter/expansion.shtml.

The latest plan, MTEP 05, identifies, through its Baseline Reliability study process, 615 planned or proposed facility additions or enhancements representing an investment of $2.91 billion through 2009, primarily to maintain reliability. This is substantially above the $1.96 billion that was estimated for the six-year period 2002-2007 in MTEP 03.

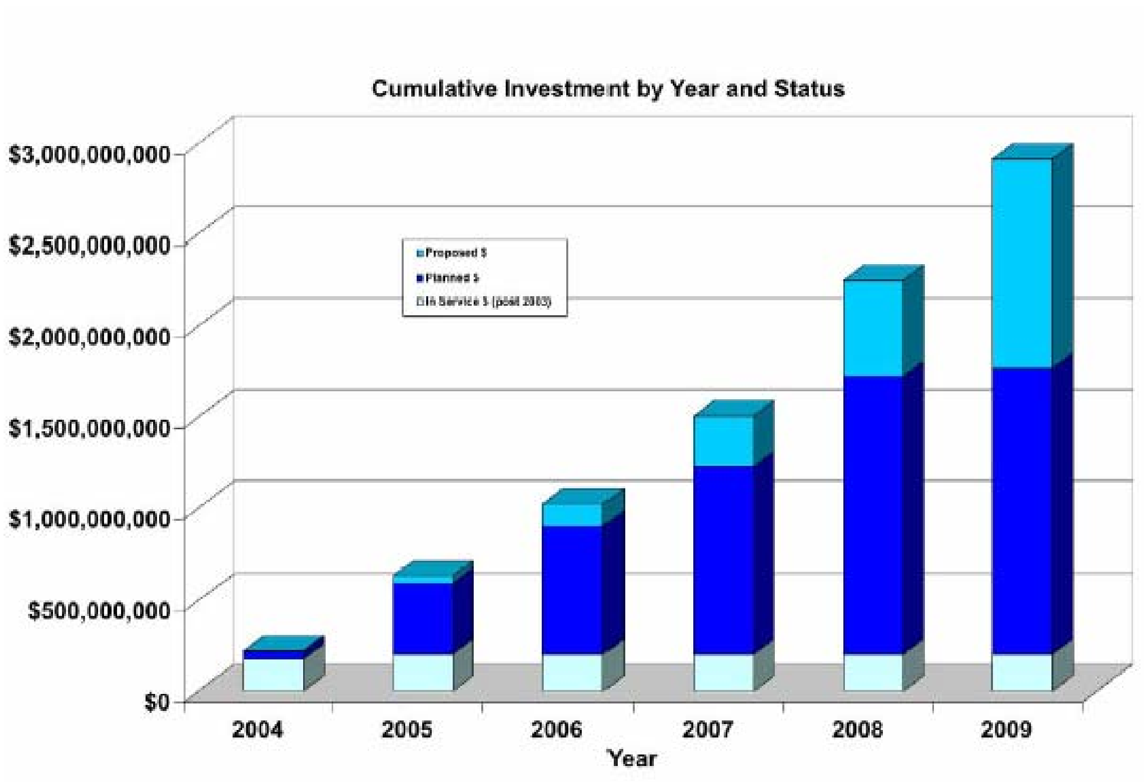


Figure 1: Cumulative Projected Spending All Projects

In addition to these facilities required primarily for reliability purposes, MTEP 05 describes two other large scale “Exploratory” plans that continue to be evaluated by the Midwest ISO and stakeholders for their potential regional benefits.

The results of the Baseline Reliability study of MTEP 05 indicate that the Midwest ISO Transmission System as projected for the year 2009 is expected to be able to perform in accordance with NERC Planning Standards for normal system conditions, events involving loss of a single transmission facility, and for most events involving loss of more than one facility. This performance will require that the ***Planned*** projects listed in Appendix A to the report go forward, and that the ***Proposed*** projects or suitable alternatives are in place.

About 5,123 miles of transmission line upgrades are projected through 2009, which is about 4.6 % of the approximately 112,000 miles of line existing throughout the Midwest ISO area.

Less than 2 %, however, involve lines on new transmission corridors. About 59 % of the expected total transmission line and substation enhancements are at 230 kV and above.

Transmission system adequacy in supporting deliverability of resources to load was evaluated for the 2009 Plan year n MTEP 05. The Midwest ISO Reliability Authority (RA) area was subdivided into 14 LOLP zones for testing the ability of a load zone to meet its reliability requirements through internal generation plus the use of transmission system for import of external resources. In 2009, for 5 of the 14 zones the internal generation mix alone was sufficient to meet the reliability criteria of 1 day in 10 years or a Loss of Load Probability (LOLP) value of 0.1, without depending on support from transmission ties. For the remaining 9 zones, the amount of transmission support needed to sustain reliability criteria was within the import transfer capability of the transmission system.

MTEP 05 also evaluated operational issues involving frequent NERC TLR, as well as areas of low AFC that limit commercial use of the system, and constraints that limit full allocations of financial transmission rights. There are 841 Midwest ISO flowgates listed in the September, 2004, NERC book of flowgates. TLR was called on 316 of these flowgates during the 48-month period from January 1, 2001, through December 31, 2004. Over this period, 24 Midwest ISO flowgates accounted for 67% of flowgate hours in TLR (each of these 24 flowgates were in TLR for 1% of the time or more).

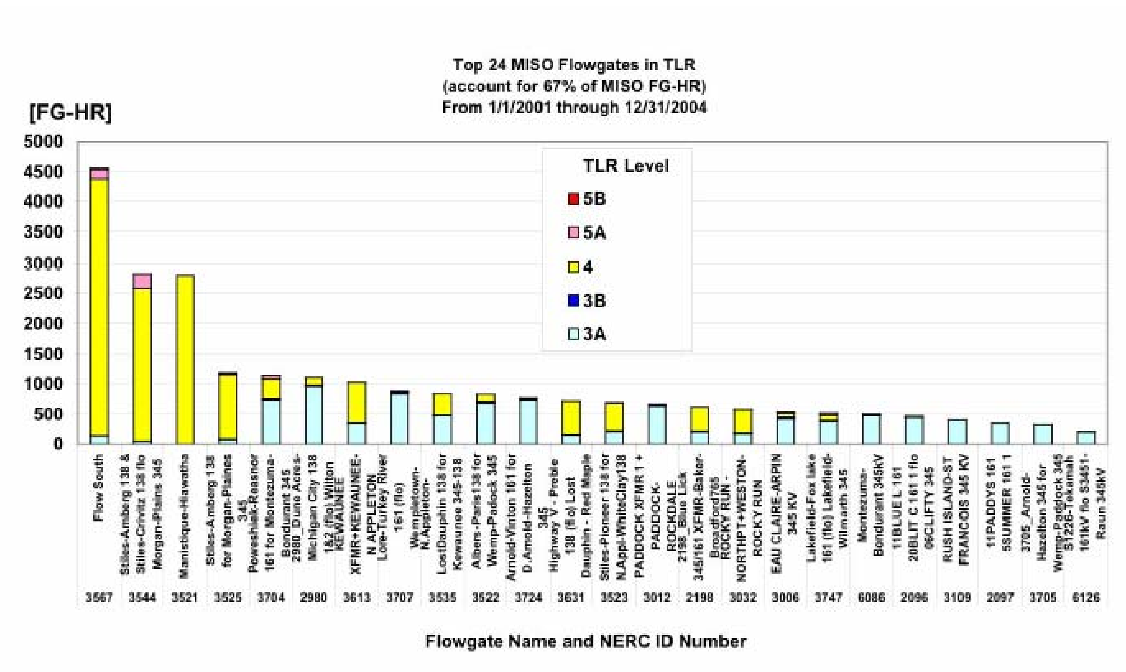
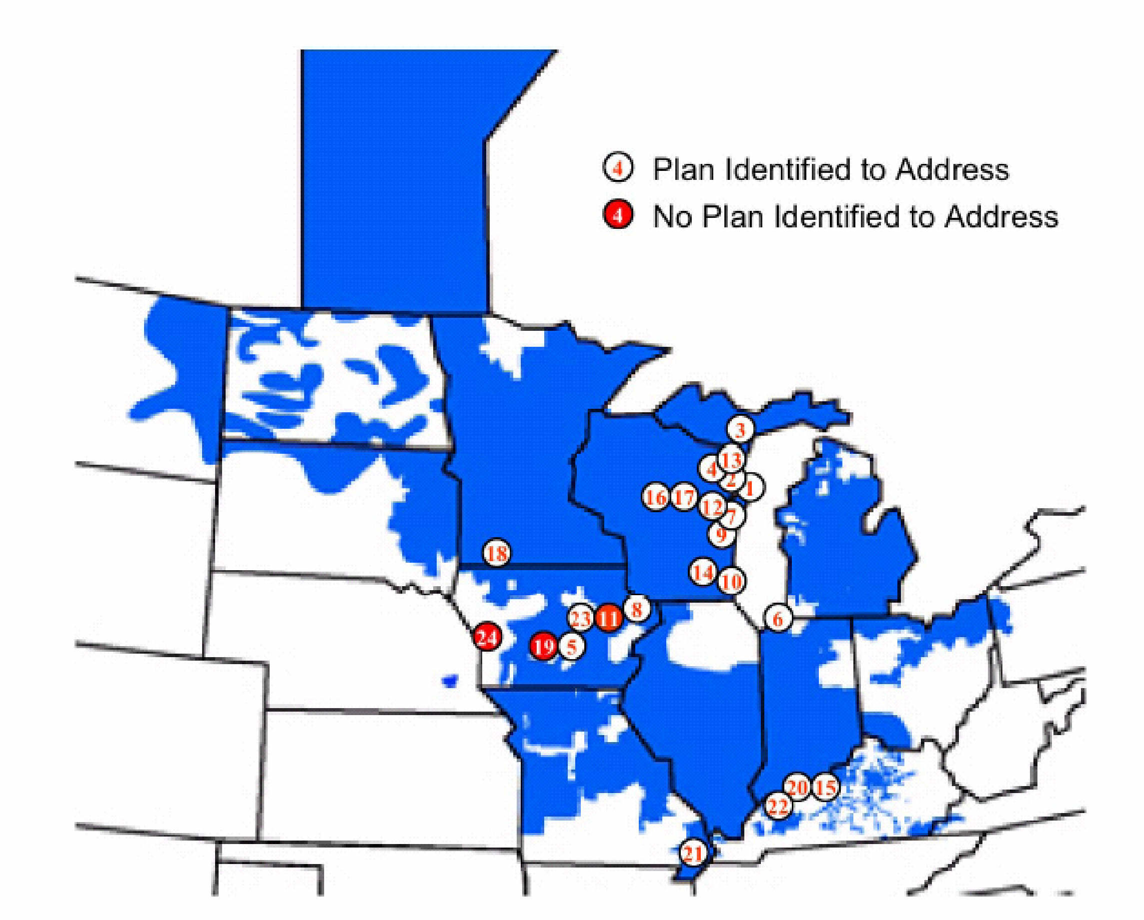


Figure 2: Flowgate Name and NERC ID Number

Plans identified in this Midwest ISO Transmission Expansion Plan address many of these constraints that fall within the Midwest ISO footprint. The following figure shows the specific flowgates that have most frequently involved TLR and that are addressed by projects in this plan, highlighted in white circles.



3: Specific Flowgates That Have Most Frequently Involved TLR

In the first Midwest ISO Transmission Expansion Plan, MTEP 03, the Midwest ISO evaluated at a high level the potential economic benefits of large regional transmission projects under various postulated generation development scenarios. MTEP 03 evaluated a dozen such plans based on analysis of the base planned transmission system, and its ability to accommodate substantial new additions of coal and wind generation, as well as gas generation based the interconnection queues at the time. This study is available on the Midwest ISO web site. The transmission and generation scenario analysis showed generally that there was significant potential for the right regional transmission to result in substantial reductions in marginal energy costs, particularly if that transmission was coupled with introduction of low cost coal and wind energy resources.

Among the dozen potentially regionally beneficial expansion concepts reviewed in MTEP 03, two have been addressed further in this MTEP 05, because of the potential benefits that the preliminary analyses showed, and because of significant stakeholder interest in these two concepts. These two expansion concepts are referred to as 1) the Northwest Exploratory Project, and 2) the Iowa–Southern Minnesota Exploratory Project.

Both projects would provide enhanced access by coal and wind resources to load centers in the Midwest ISO. It is the intention of the Midwest ISO to continue the development of these regional expansion projects through further evaluation of the nature, value, and beneficiaries of these plans. The Midwest ISO intends to recommend such plans as these to the Midwest

ISO Board of Directors at such time as the Midwest ISO in collaboration with interested stakeholders can complete these evaluations, and a determination of cost responsibility and recovery can be made, consistent with the Midwest ISO tariff and the Transmission Owners Agreement.

The Northwest Exploratory study involves generation in the Dakotas and transmission upgrades from the Dakotas to Minnesota. The Iowa-Southern Minnesota Exploratory study involves generation in northern Iowa, southern Minnesota, and South Dakota and transmission upgrades from generation to major load centers in Minnesota, Iowa, and Wisconsin. Both studies are in progress and results to date and future work efforts are described in this report.

b. Planning Issues

In early 2006 the Midwest ISO will complete its fourth year of operations, and first year of a transmission and energy market. The transition for the Midwest to an energy market environment, coupled with the diversity of energy resources and of the transmission systems infrastructure in the region, forms the basis for the key planning opportunities and challenges facing the Midwest ISO.

Planning in a New Market Environment

The Midwest ISO Board of Directors recently provided a set of Guiding Principles for the development of Midwest ISO regional transmission expansion Plans. These principles provide that Midwest ISO regional expansion planning should identify efficient investments in the transmission infrastructure system to:

1. Make the benefits of a competitive energy market available to customers by providing access to the lowest possible electric energy costs
2. Provide a transmission infrastructure that safeguards local and regional reliability
3. Support state and federal renewable energy objectives by planning for access to all such resources, and
4. Make available to state and federal energy policy makers transmission system scenarios and models to provide context and inform the choices they face

Market operations provide the opportunity for considerably expanded use of the transmission system. System planning at the Midwest ISO has as its objectives the reliable support of these expanded market opportunities. Allocation of transmission expansion costs under market operations should be consistent with this expanded use of the transmission system. In that light, the Midwest ISO and its stakeholders have been developing for nearly a year and a half, a transmission pricing policy that is guided by the indications of cost causation and beneficiaries of transmission expansions. We are also integrating LMP modeling applications into the planning process as additional tools to determine expansions needed to provide efficient and reliable service to transmission customers.

Market operations could also have an impact on the economic viability of certain existing resources, and this could impact generator retirements as has been seen in other regions, and must be prepared for.

Energy Policy Impacts

Regional planning of the energy delivery infrastructure must support national energy policy goals. The Energy Policy Act requires that the DOE in consultation with the affected states shall conduct a study of transmission congestion and issue a report designating "national interest electric transmission corridors." This classification is based on the need for reasonably priced electricity, the need to access more supply and diversify energy sources, and effects on energy independence, national defense and homeland security. The Midwest ISO expects to work closely with the DOE and the states within which the Midwest ISO operates in meeting these requirements. This work is consistent with Midwest ISO planning practices in place that seek to identify transmission issues associated with providing access to the abundant supplies of coal, wind, hydro, and other resources within the Midwest ISO. Several Midwestern states have renewable energy portfolio standards or objectives, and regional planning will support these initiatives. In addition, environmental policies within the United States and Canada could significantly impact the patterns of Midwest ISO transmission system usage.

Coordination at Seams

The Midwest ISO has extensive seams with several other RTO and non-RTO transmission providers, operating with and without market structures that provide significant challenges for coordinated and equitable operations. Many Midwest ISO stakeholders have significant concerns about the impacts of these seams and the Midwest ISO is working with border entities to approach "seamless" operations across these boundaries. See Section IV of this report for more details on these efforts.

c. Statistics

i. Load Growth

The Midwest ISO does not currently prepare a long-term load forecast. Load projections are reported by Network Customers under the tariff, and are represented in planning models developed collaboratively between the Midwest ISO and our transmission-owning members. Members also provide load forecasts through the NERC regional reporting processes. Resource adequacy is established under the tariff by requiring load serving entities to report their Network Resources that will be used to meet State and NERC regional resource adequacy guidelines. Based on the current Midwest ISO peak load measurements, aggregate load growth rate projections reported by members and non-members to NERC, and activity from the Midwest ISO generation interconnection queue, estimates of peak load and capacity are shown in the figure below.

At an estimated load growth rate of 1.9 %, the peak load of Midwest ISO for 2009 would be about 131,000 Mw, which is about equal to the current installed capacity of 131,000 MW. There is about 11,554 Mw of generation in the current queue with executed Interconnection agreements and service dates between 2004 and 2009 inclusive. There is an additional 17,521 MW of generation in the queue for service over this period that have not yet executed interconnection agreements.

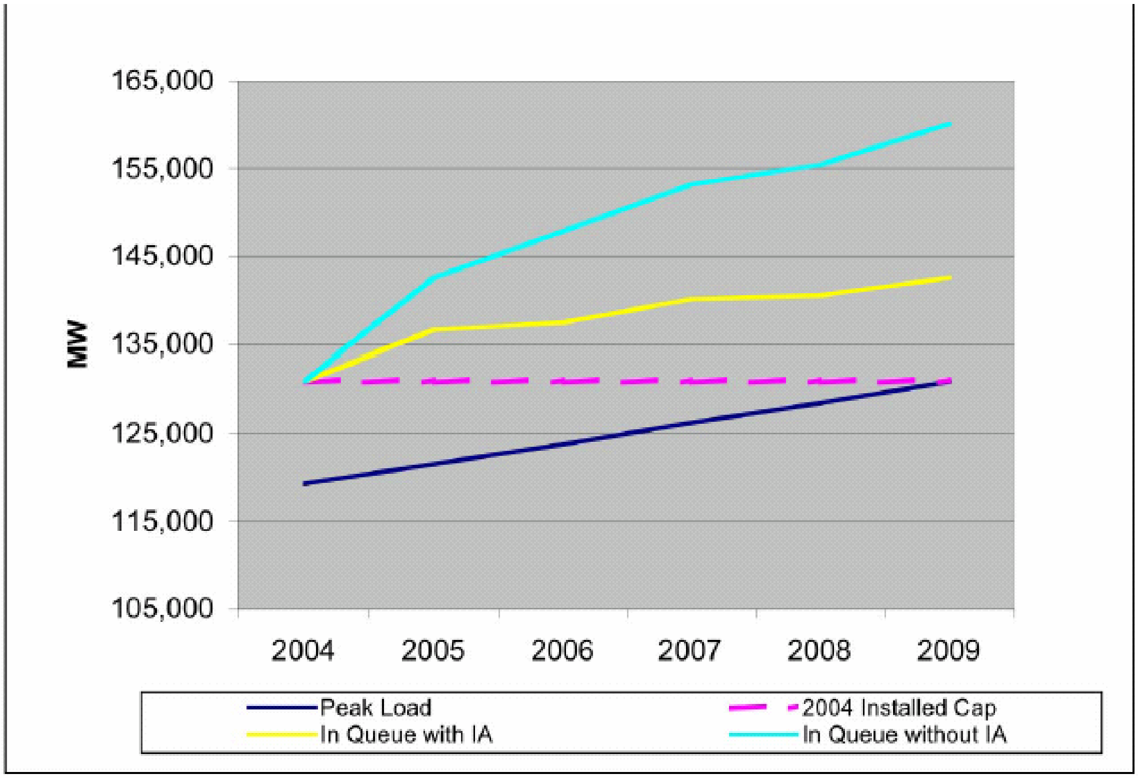


Figure 4: Load and Generation Trends

ii. Interconnection Queue

Overall, 6,397 MW of new generation have executed Interconnection Agreements in the Midwest ISO since 2001. 1,783 MW of this has been Wind-powered.

The figure below shows the active generation interconnection queue entries for the two-year period January 2003 to January 2005. The number of active entries has remained relatively stable between approximately 80 and 100. During this time, more than 150 new requests have entered the queue.

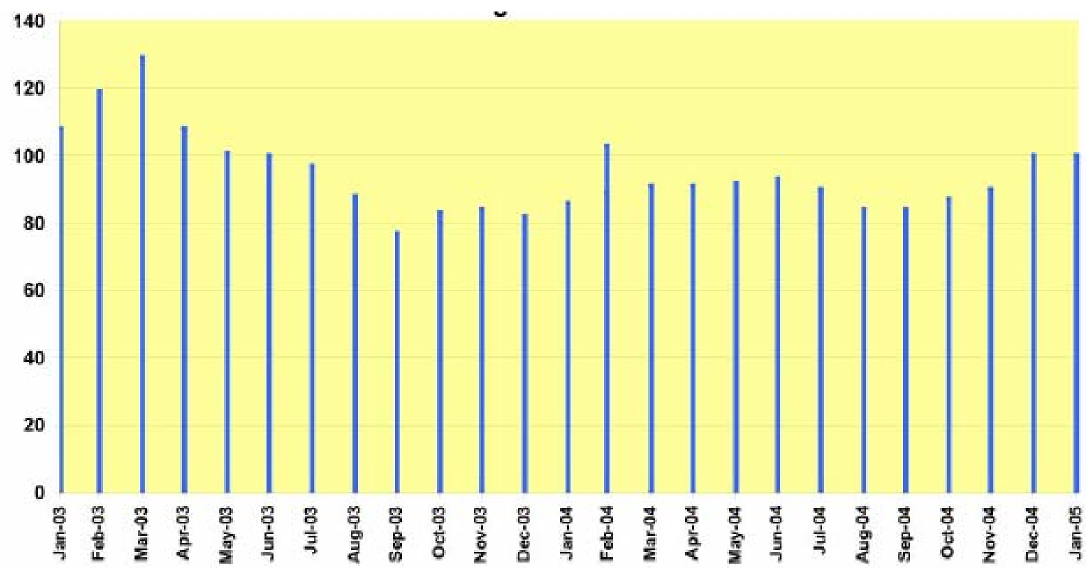


Figure 5: Number of Active Entries in Queue by Date

There has been a considerable shift in the type of requests the Midwest ISO is processing. As shown in the figure below, 65 % of current entries are for wind power, 18 % for natural gas and 12 % coal.

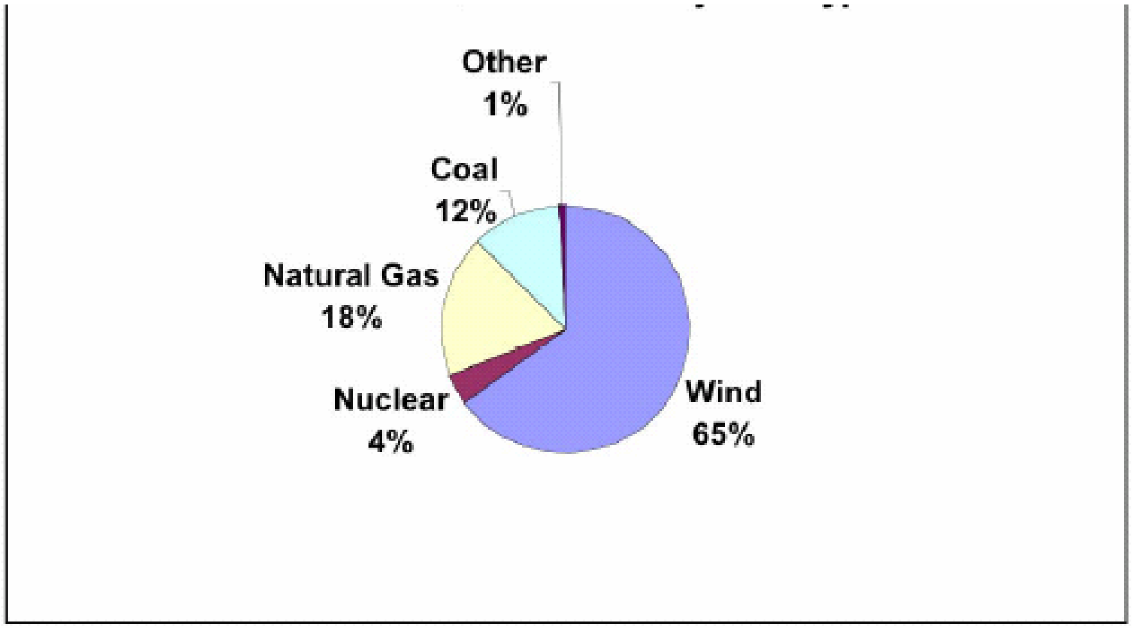


Figure 6: 2005 Queue – Number of Queue Entries by Fuel Type

Compared to the entries in the 2003 queue shown in the figure below, this is a 30 % increase in wind requests, 50 % increase in the number of coal requests and a 50 % decrease in gas requests.

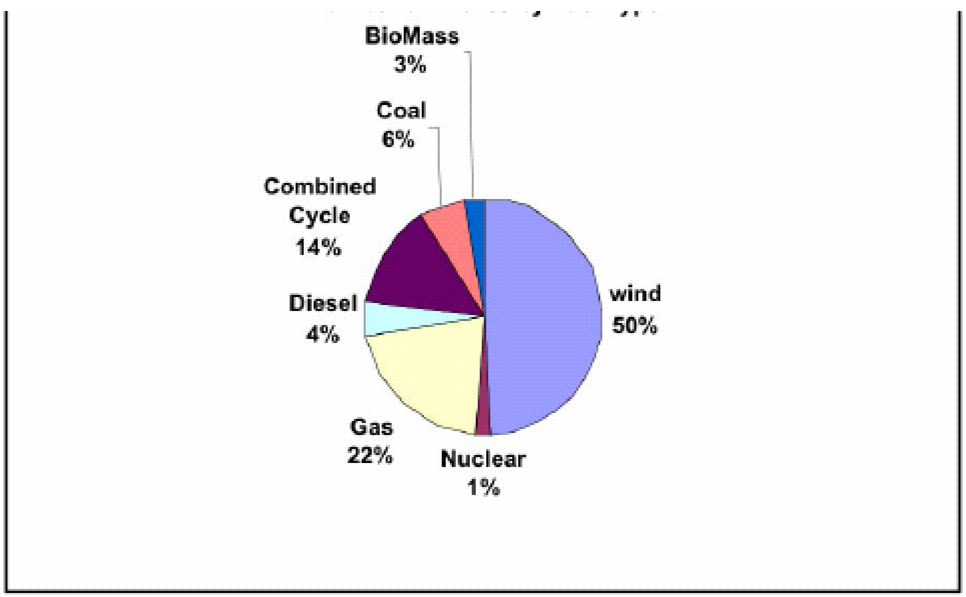


Figure 7: 2003 Queue – Number of Queue Entries by Fuel Type

While the number of wind entries has increased significantly, in terms of capacity, the 2005 queue shows that the predominant fuel type is coal with 6700 MW, followed by wind with 5800 MW and gas with gas with 5000 MW.

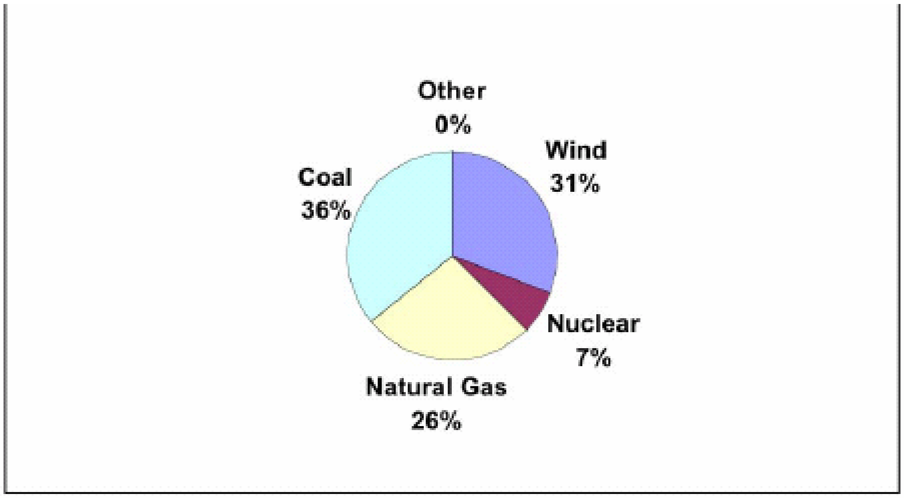


Figure 8: 2005 Queue – Generation Capacity in Queue by Fuel Type

This compares to the 2003 queue shown below, in which the overwhelming capacity of the queue was in natural gas plants. Most Combined Cycle plants are gas fired also.

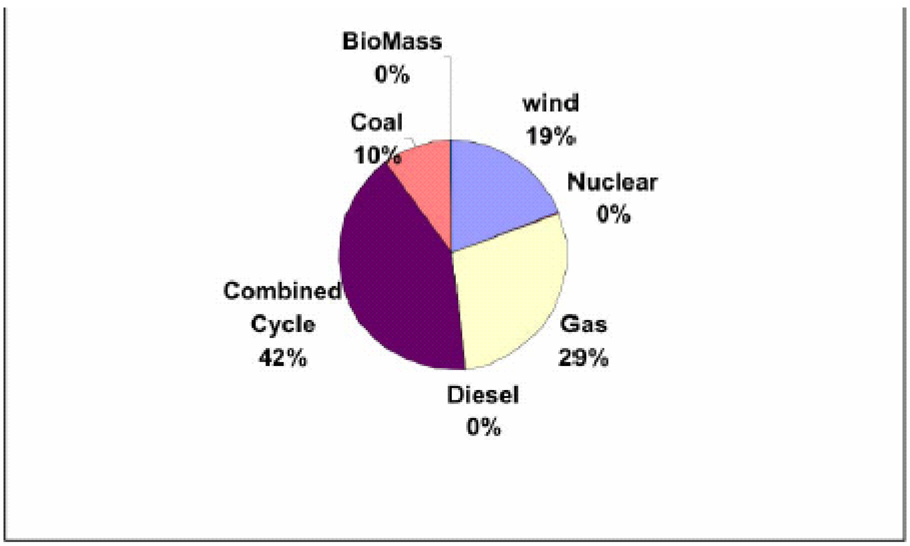


Figure 9: 2003 Queue – Generation Capacity in Queue by Fuel Type

The plot below shows the geographic distribution of the queue entries.

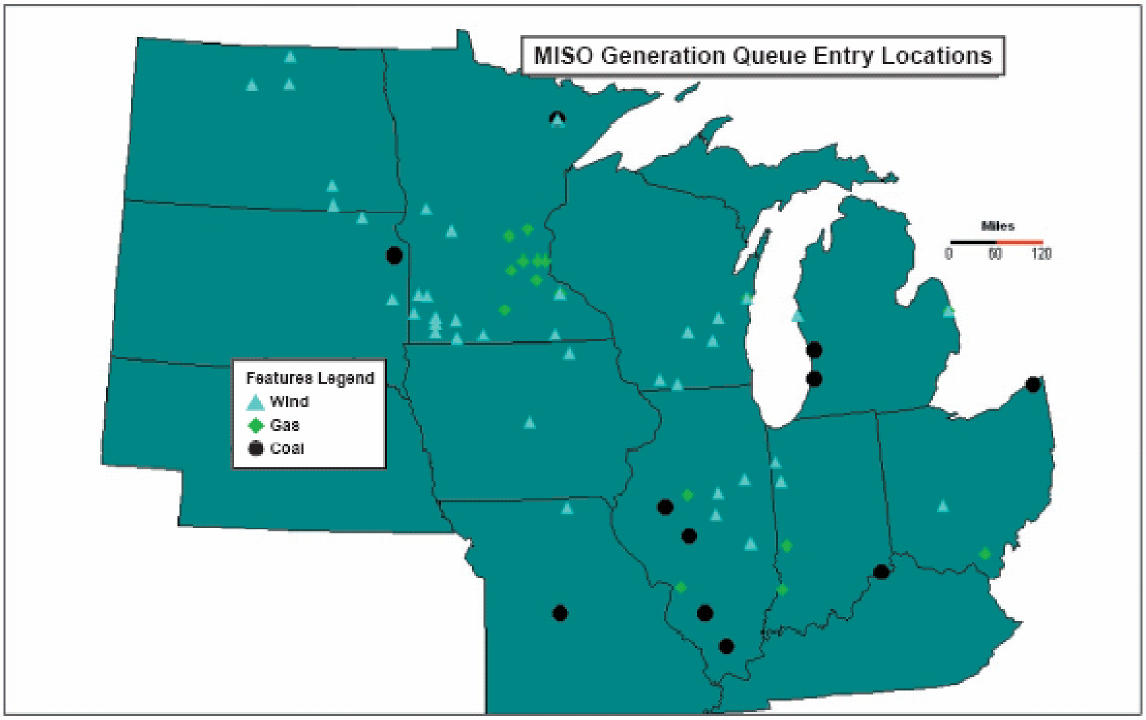


Figure 10: MISO Generation Queue Entry Locations

iii. Transmission Build

Our members have reported more than $673,000,000 in transmission investment to the Midwest ISO since 2001 (2002 and forward). This has included 2,017 miles of upgraded or new transmission line.

About 5,123 miles of transmission line upgrades are projected through 2009, which is about 4.6 % of the approximately 112,000 miles of line existing throughout the Midwest ISO area. Less than 2 %, however, involve lines on new transmission corridors. About 59 % of the expected total transmission line and substation enhancements are at 230 kV and above.

iv. Resource Adequacy

The Midwest ISO is currently developing with stakeholders a permanent implementation of a resource adequacy requirement. The initial resource adequacy requirements under the Transmission and Energy Market Tariff (TEMT) can be found in Module E to the TEMT on the Midwest ISO website at http://www.midwestiso.org/. Module E requires Load Serving Entities to identify sufficient deliverable Network Resources to meet reserve obligations or guideline of individual States or applicable Regional Reliability Organizations for a twelve-month forecast horizon.

NYISO

a. Summary of Most Recent Plans

The peak loads that are forecast for the NYCA for the years 2005 through 2015 show a compound growth rate of 1.2%. The forecast net energy for the same ten-year period shows a compound growth rate of 1.2%. The forecast details are presented in section c.

Within the New York Control Area (NYCA), the New York State Reliability Council (NYSRC) has the responsibility of setting the installed minimum capacity requirements consistent with the NPCC reliability criterion. The NYISO assigns a proportion of this installed capacity requirement to each Load-Serving Entity (LSE) located within the NYCA. The NYISO administers an installed capacity market that allows LSEs to procure installed capacity to meet their requirements either through bilateral arrangements or auctions conducted by the NYISO. Failure to meet these requirements will result in the imposition of financial penalties.

LSEs within the NYCA may meet their installed capacity requirements through procurement of qualified capacity from resources within the NYCA or from resources located in neighboring control areas directly interconnected to the NYCA. Resources located within the PJM, ISO-NE and Hydro Quebec control areas may qualify as installed capacity suppliers to the NYISO. Currently the Ontario IMO, the operator of the other directly interconnected control area to the NYCA, does not meet the NYISO's requirement relating to the recall of transactions associated with installed capacity sold to New York. Therefore, resources located within this control area do not qualify as installed capacity suppliers to the NYISO.

The NYSRC has determined that an installed reserve of 18% over the NYCA year 2005 summer peak load is required to meet the NPCC reliability criterion. The NYSRC revisits the issue of the installed reserve margin each year. For the purposes of this report, the NYISO assumes that the 18% installed reserve margin will apply throughout the 10 year reporting period. Existing capacity within the NYCA and known purchases and sales with neighboring control areas provide sufficient capacity to meet the 18% installed reserve margin through the year 2007.

The NYISO maintains an interconnection list of proposed generation facilities. Approximately 2200 MW of the new capacity on the list, which has completed construction or is under construction, has been included in the NYISO installed reserve margin calculation through 2015. The balance of the list, which is not under construction and has qualified for inclusion in a class year, has been categorized as Proposed Resource Additions. The projects categorized as Proposed Resource Additions total in excess of the projected capacity that would need to be constructed in order to maintain the 18% installed reserve margin. These specific capacity additions and class year projects are presented in section c.

Additionally, part of the New York installed capacity market design allows Special Case Resources (i.e., distributed generation and interruptible load customers that are not visible to the NYISO Market Information System) to participate in the installed capacity market. These customers become another source of capacity for LSEs.

In addition, to capacity and demand resources, the NYCA has a multitude of proposed transmission additions. The majority of these projects is proposed by transmission owners and is being constructed to ensure reliability criteria are met. A small number of the projects are merchant projects or market driven projects. The specific transmission projects are presented in section c.

b. Planning Issues

The NYISO currently has a number of important planning issues that are under continuous review. They include, but are not limited to the following:

i. Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) are state standards established for load-serving entities (LSE) requiring that a specific percent of their energy be supplied each year by renewable forms of energy. Starting in a specified year, this percentage increases each year to some maximum amount. New York has adopted a standard which requires that 25% of the State's energy requirements come from eligible renewable resources by 2013. The current level which includes the State's hydro resources is 19.5%.

It is expected the majority of the additional requirement will be supplied by wind generators. The NYISO interconnection queue for wind generation now totals in excess of 5,000 MW. Wind generators, which are intermittent resources and have other unique electrical characteristics which pose challenges for planning and operations of the interconnected system. The NYISO has completed a study conducted by GE Energy which evaluated the reliability and operating implications of the large scale integration of wind generation. The study concluded that if state-of-the-art wind technology is utilized wind generation can reliably interconnected with only minor adjustments to existing planning, operating, and reliability practices. Section c presents a listing of the wind generators currently in the NYISO interconnection queue.

ii. Retirements

Retirement of resources is a potential risk to maintaining adequate resources for the region and will affect inter-regional power flows as well. NY currently has almost 2,800 MW of planned and scheduled retirements. The retirement schedule is provided in section c.

iii. Environmental Initiatives

The are a host of new air quality and water quality rules that will apply to fossil fuel-fired power plants in New York State from the immediate present to within the next decade. These initiatives can have a significant future impact on resource availability and, thus, the reliability of the interconnected system. These initiatives include the following:

1. NYS Acid Deposition Reduction Program (ADRP): ADRP, which is a New York only power plant cap-and-trade program for nitrogen oxides (NOx) and sulfur dioxide (SO2), began October 1, 2004, for NOx and January 1, 2005, for SO2. The regulations require an approximate 40 percent reduction in NOx emissions from 2002 levels and a 50 percent reduction in SO2 emissions from current federal acid rain program levels.
2. Clean Water Act (CWA) Section 316(b) – Cooling Water Intake Structure Best Technology Available (BTA): This rule primarily applies to existing power plants (fossil fuel and nuclear) that rely on once-through cooling for steam condensers (about 20 plants in New York). The US EPA has promulgated this rule, but it will be implemented by NYSDEC through its own rules and policies, with EPA's rule as a baseline. The EPA rule requires existing power plants to demonstrate compliance with performance standards

requiring an 80-95 percent reduction in the impingement mortality of aquatic organisms and a 60-90 percent reduction in fish egg and larvae entrainment in cooling water intakes, both from uncontrolled levels. These performance standards are based on the impacts that would be achieved with closed loop cooling systems (i.e., cooling towers).

A "comprehensive demonstration study" of the existing impacts and proposed BTA, considering technical and economic viability, must be submitted as part of the water discharge permit renewal application (most will be due in the 2007-2009 timeframe). Though allowed by the EPA rule, NYSDEC has indicated that they will not consider economic viability in the determination of BTA. This policy could force most, if not all, existing power plants to install cooling towers.

3. New Source Review (NSR): NSR regulations require existing facilities that undergo a major modification to install modern air emission control equipment for air contaminants impacted by the modification. In the late 1990's EPA and New York State Department of Environmental Conservation (NYSDEC) began enforcement action against the coal-fired power plants in New York and several other states for allegedly violating NSR requirements. The basis for the enforcement actions was the interpretation of what constitutes routine maintenance, repair and replacement, which is exempt from the definition of major modification. The power plant industry and regulatory agencies disagree on this interpretation, but several companies have agreed to settle the enforcement actions. In New York, the settlements include power plants owned by Mirant, AES and NRG and have resulted in the commitment to install millions of dollars in emission controls or shut down plants. Enforcement actions are still outstanding for RG&E and Dynegy.
4. Clean Air Interstate Rules (CAIR): On March 10, 2005, EPA finalized new cap-and- trade programs for reducing emissions of SO2 and NOx by approximately 70 percent in 28 eastern states. Implementation of the rules will be in two phases. Phase I for NOx begins in 2009 and Phase II begins in 2015. Phase I for SO2 begins in 2010 and Phase II begins in 2015.
5. Clean Air Mercury Rule: On March 15, 2005, EPA finalized a rule for controlling mercury emissions from power plants through a new cap-and-trade program for mercury emissions. The rule limits mercury emissions from new and existing coal-fired power plants, and creates a market-based cap-and-trade program that will permanently cap utility mercury emissions in two phases: the first phase cap is 38 tons beginning in 2010, with a final cap set at 15 tons beginning in 2018. However, EPA implements the cap by setting a mercury budget for each state, but it is left up to each state to determine how they will meet that budget – either by participating in EPA's trading program or some other mechanism (e.g., emission standards forcing all units to add emission controls). In comments submitted to EPA, New York has indicated that they do not support the cap-and-trade program, and thus would not allow mercury allowance trading if given the option.
6. Regional Greenhouse Gas Initiative (RGGI): RGGI is a cooperative effort by 9 Northeastern and Mid-Atlantic states to reduce carbon dioxide emissions

through a regional cap-and-trade program. A model rule for the program, which will require fossil fuel-fired electric power generators greater than 25 MW to reduce carbon dioxide emissions below 1990 levels, is expected by August 2005. An implementation date has not been established, but is likely to be 2008 or 2009. Staff from participating states' environmental and public service agencies are currently in the process of evaluating various cap level scenarios and the resulting energy and economic impacts.

7. Regional Haze Rule: To reduce haze in national parks and wilderness areas, EPA issued a regional haze rule requiring Best Available Retrofit Technology (BART) on certain facilities built between 1962 and 1977 that have the potential to emit more than 250 tons a year of visibility-impairing pollution (i.e., SO2, NOx and fine particulate matter). Those facilities fall into 26 categories, including fossil fuel-fired power plants. This rule could affect 13 New York power plants and could result in the addition of BART controls by 2013. The Regional Haze Rule will be implemented through a New York State implementation plan, which will not be submitted until 2007. Potential BART controls include SO2 scrubbers, selective catalytic reduction of NOx and fabric filter particulate controls.

Although there are a significant number of initiatives whose ultimate disposition and impact have not yet been determined, the NYISO primary concern at this point is that these impacts be determined with sufficient lead time that any adverse impact on system reliability can be mitigated within the NYISO comprehensive planning process.

iv. Blackout-Related Issues

There are numerous additional blackout-related studies and requirements (both international, regional and local) that must be accommodated in future planning efforts such as under voltage load shedding.

c. Statistics

i. Load Growth

NYISO Long Term Forecast - 2005 to 2015

Energy - GWh

Year	Low	Base	High
2004 Actual		160,211	
2004 Weather Normalized		161,257	
2005	163,972	**164,050**	165,624
2006	166,538	166,790	168,813
2007	168,509	169,400	172,399
2008	170,373	172,100	175,862
2009	171,747	174,290	178,811
2010	173,103	176,340	181,634
2011	174,193	178,060	184,108
2012	175,029	179,520	186,292
2013	175,633	180,710	188,196
2014	176,083	181,740	189,915
2015	176,635	182,880	191,742

Summer Peak - MW

Year	Low	Base	High
2004 Actual		28,433	
2004 Weather Normalized		31,400	
2005 *	31,891	**31,960**	32,204
2006	32,242	32,400	32,762
2007	32,572	32,840	33,357
2008	32,934	33,330	33,961
2009	33,250	33,770	34,508
2010	33,576	34,200	35,057
2011	33,861	34,580	35,556
2012	34,083	34,900	35,987
2013	34,267	35,180	36,372
2014	34,413	35,420	36,709
2015	34,584	35,670	37,063

Winter Peak - MW

Year	Low	Base	High
04-05 Actual		25,541	
04-05 Weather Normalized		25,250	
2005-06	25,339	**25,350**	25,534
2006-07	25,642	25,670	25,910
2007-08	25,874	25,980	26,330
2008-09	26,093	26,290	26,733
2009-10	26,253	26,550	27,076
2010-11	26,412	26,790	27,402
2011-12	26,539	26,990	27,687
2012-13	26,636	27,160	27,938
2013-14	26,707	27,300	28,157
2014-15	26,759	27,410	28,353
2015-16	26,823	27,550	28,562

Annual Avg Growth Rates (Energy - Low)		Annual Avg Growth Rates (Summer - Low)		Annual Avg Growth Rates (Winter - Low)	
94-04 (Normal)	1.01%	94-04 (Normal)	1.41%	94-04 (Normal)	0.79%
04-15 (Actual)	0.89%	04-15 (Actual)	1.80%	04-15 (Actual)	0.45%
04-15 (Normal)	0.83%	04-15 (Normal)	0.88%	04-15 (Normal)	0.55%

Annual Avg Growth Rates (Energy - Base)		Annual Avg Growth Rates (Summer - Base)		Annual Avg Growth Rates (Winter - Base)	
94-04 (Normal)	1.01%	94-04 (Normal)	1.41%	94-04 (Normal)	0.79%
04-15 (Actual)	1.21%	04-15 (Actual)	2.08%	04-15 (Actual)	0.69%
04-15 (Normal)	**1.15%**	04-15 (Normal)	**1.17%**	04-15 (Normal)	**0.80%**

Annual Avg Growth Rates (Energy - High)		Annual Avg Growth Rates (Summer - High)		Annual Avg Growth Rates (Winter - High)	
94-04 (Normal)	1.01%	94-04 (Normal)	1.41%	94-04 (Normal)	0.79%
04-15 (Actual)	1.65%	04-15 (Actual)	2.44%	04-15 (Actual)	1.02%
04-15 (Normal)	1.59%	04-15 (Normal)	1.52%	04-15 (Normal)	1.13%

ii. Interconnection Queue

As of April 1, 2005

Interconnection Projects that met Class Year Milestones

OWNER / OPERATOR	STATION UNIT	ZONE	DATE	CAPABILITY (kW) SUMMER	WINTER	UNIT TYPE
Projects Under Construction						
Consolidated Edison of NY, Inc.	East River Repowering	J	7/1/2005	288000	288000	Combined Cycle
New York Power Authority	NYPA 500 MW Project	J	1/1/2006	500000	500000	Combined Cycle
SCS Energy, LLC	Astoria Energy (Phase 1)	J	4/1/2006	500000	500000	Combined Cycle
Calpine Eastern Corporation	Bethpage 3	K	5/1/2005	79900	79900	Combined Cycle
Pinelawn Power, LLC	Pinelawn Power I	K	5/1/2005	79900	79900	Combined Cycle
PSEG Power NY	Bethlehem Energy Center	ROS	7/1/2005	750000	750000	Combined Cycle
				2197800	2197800	
Proposed Resource Additions						
Calpine Eastern Corporation	JFK Expansion	J	6/1/2006	45000	45000	Combustion Turbine(s)
SCS Energy, LLC	Astoria Energy (Phase 2)	J	4/1/2007	500000	500000	Combined Cycle
PG&E/Liberty Generating Co., LLC	Liberty Generation	J	5/1/2007	400000	400000	Combined Cycle
Bay Energy, LLC	Bay Energy	J	6/1/2007	79900	79900	Combustion Turbine(s)
NYC Energy, LLC	Kent Avenue	J	6/1/2007	79900	79900	Combustion Turbine(s)
Fortistar, LLC	Fortistar VAN	J	7/1/2007	79900	79900	Combustion Turbine(s)
Fortistar, LLC	Fortistar VP	J	7/1/2007	79900	79900	Combustion Turbine(s)
PSEG Power In-City 1, LLC	Cross Hudson Project	J	7/1/2008	550000	550000	Combined Cycle
Reliant Energy NY	Astoria Repowering (Phase 1)	J	7/1/2010	540000	540000	Combined Cycle
Reliant Energy NY	Astoria Repowering (Phase 2)	J	9/1/2011	540000	540000	Combined Cycle
KeySpan Energy, Inc.	Spagnoli Road Energy	K	7/1/2008	250000	250000	Combined Cycle
American National Power	Brookhaven Energy Center	K	7/1/2009	580000	580000	Combined Cycle
Flat Rock Wind Power, LLC	Flat Rock Wind Power (Phase 1)	ROS	12/1/2005	200000	200000	Wind Turbines
Global Winds Harvest Inc.	Prattsburgh Wind Park	ROS	7/1/2006	79500	79500	Wind Turbines
Flat Rock Wind Power, LLC	Flat Rock Wind Power (Phase 2)	ROS	12/1/2006	100000	100000	Wind Turbines
Besicorp-Empire Development Company, LLC	Empire State Newsprint	ROS	7/1/2007	660000	660000	Combined Cycle
Lockport Merchant Associates, LLC	Lockport II Gen Station	ROS	7/1/2007	79900	79900	Combustion Turbine(s)
Calpine Eastern Corporation	Wawayanda Energy Center	ROS	7/1/2008	540000	540000	Combined Cycle
Mirant Corporation	Bowline Point 3	ROS	7/1/2008	750000	750000	Combined Cycle
				6134000	6134000	
			Total	8331800	8331800	

Wind Interconnection Queue which totals 5,258.5 MW

Queue Pos.	Owner/Developer	Project Name	Date of IR	SP (MW)	Location County/State	Interconnection Point	Utility
N/A	US Generating Company	Madison	N/A	11.5		County Line-Brothertown li	NYSEG
N/A	ChiEnergy	Wethersfield Wind Power	N/A	6.6		NM-NG 34.5kV	NM-NG
55	Canastota Wind Power, LLC	Fenner Wind Energy Fac.	3/14/00	30		Fenner-Whitman	NM-NG
113	Global Winds Harvest, Inc.	Prattsburgh Wind Park	4/22/02	75	Yates, NY	Eelpot Rd-Flat St. 115kV	NYSEG
117	Chautauqua Windpower, LLC	Chautauqua Windpower	5/14/02	50	Chautauqua, NY	Dunkirk-S. Ripley 230kV	NM-NG
119	ECOGEN, LLC	Prattsburgh Wind Farm	5/20/02	79.5	Yates, NY	Eelpot Rd-Flat St. 115kV	NYSEG
N/A	Green Power Energy, LLC	Cody Road Wind Farm	3/5/03	9		Oneida-Cortland line	NM-NG
127A	Airtricity Developments, LLC	Munnsville	10/9/02	40	Madison, NY	46kV line	NYSEG
135	UPC Wind Management, LLC	Canandaigua Wind Farm	5/30/03	81	Ontario, NY	Avoca 230kV line	NYSEG
141	Flat Rock Wind Power, LLC	Flat Rock Wind Power	8/27/03	300	Lewis, NY	Adirondack-Porter 230kV	NM-NG
142	Airtricity Developments, LLC	Hartsville Wind Farm	10/30/03	50	Steuben, NY	Bennett-Palmiter 115kV lin	NYSEG
144	Invenergy Wind, LLC	High Sheldon Windfarm	2/18/04	198	Wyoming, NY	Stolle Rd-Meyer 230kV	NYSEG
147	NY Windpower, LLC	West Hill Windfarm	4/16/04	40	Madison, NY	Oneida-Cortland 115kV	NM-NG
150	Reunion Power, LLC	Cherry Valley Wind Power	6/17/04	80	Otsego, NY	East Springfield 115kV	NYSEG
152	Invenergy Wind, LLC	Stamford Wind Project	7/23/04	129	Delaware, NY	Axtell Road-Grand Gorge 1	NYSEG
155	Invenergy NY, LLC	Canisteo Hills Windfarm	9/17/04	148.5	Steuben, NY	TBD	NYSEG
156	Atlantic Renewable Energy Corp.	Fairfield Wind Project	9/28/04	120	Herkimer, NY	Salisbury 115 kV	NM-NG
157	Orion Energy, LLC	Orion Energy NY I	10/12/04	100	Herkimer, NY	TBD	NM-NG
158	Orion Energy, LLC	Orion Energy NY II	10/12/04	100	Montgomery, NY	TBD	NM-NG
160	Atlantic Renewable Energy Corp.	Burke Wind Project	10/12/04	102.3	Franklin, NY	Willis-Malone 115 kV	NYSEG
161	NY Windpower, LLC	Marble River Windfarm	12/7/04	76	Clinton, NY	Willis-Plattsburgh 230kV	NYPA
162	AES Somerset, LLC	Niagara Windpower	12/15/04	70	Niagara, NY	TBD	NYSEG
163	Clipper Windpower Inc.	Pine Hill Wind Generation	1/13/05	100	Steuben, NY	Bath-Montour Falls 115kV	NYSEG
164	FPL Energy	Long Island Offshore Wind	1/28/05	140	Suffolk, NY	Sterling Substation	LIPA
*165	UPC Wind Management, LLC	Genesee Wind Farm	1/31/05	500	Genesee, NY	Batavia Substation 115kV	NM-NG
166	AES New York Wind, LLC	St. Lawrence Wind Farm	2/8/05	130	Jefferson, NY	Lyme Substation	NM-NG
167	AES New York Wind, LLC	St. Lawrence Wind Farm II	2/8/05	80	Jefferson, NY	Lyme Substation	NM-NG
168	Zilkha Renewable Energy	Perry Wind Farm	2/8/05	132	Wyoming, NY	Stolle Rd.-Meyer 230kV	NYSEG
169	Zilkha Renewable Energy	Batavia Wind Farm	2/8/05	90.8	Genesee, NY	Oakfield-Lockport 115kV	NM-NG
170	Zilkha Renewable Energy	Machias Wind Farm	2/8/05	90	Cattaraugus, NY	Cobble Hill-Valley 115kV	NM-NG
171	Zilkha Renewable Energy	Clinton County Wind Farm	2/8/05	123.8	Clinton, NY	Willis-E. Plattsburgh 230kV	NYPA
172	Noble Environmental Power, LLC	Clinton Windfield	2/14/05	80	Clinton, NY	Willis-Plattsburgh 230kV	NYPA
173	Noble Environmental Power, LLC	Bliss Windfield	2/14/05	71	Wyoming, NY	Arcade Substation 115kV	NM-NG
174	Noble Environmental Power, LLC	Altona Windfield	2/14/05	99	Clinton, NY	Willis-Plattsburgh 230kV	NYPA
175	Noble Environmental Power, LLC	Ellenburg Windfield	2/14/05	79.5	Clinton, NY	Willis-Plattsburgh 230kV	NYPA
176	Noble Environmental Power, LLC	Wethersfield Windfield 115	2/14/05	129	Wyoming, NY	Springville-Machias 115kV	NM-NG
177	Noble Environmental Power, LLC	Wethersfield Windfield 230	2/14/05	129	Wyoming, NY	Stolle-Meyer 230kV	NM-NG
178	Noble Environmental Power, LLC	Allegany Windfield	2/14/05	99	Cattaraugus, NY	Springville-Machias 115kV	NM-NG
179	Noble Environmental Power, LLC	Malone Windfield	2/14/05	159	Franklin, NY	Malone Substation 115kV	NM-NG
180	Invenergy Wind, LLC	Buffalo Rd. Wind Farm	2/23/05	165	Wyoming, NY	Stolle Rd.-Meyer 230kV	NYSEG
181	Everpower Global	Cold Spring Wind	3/21/05	102.3	Steuben, NY	Falconer-Salamanca 115kV	NM-NG
182	Everpower Global	Howard Wind	3/21/05	69.3	Cattaraugus, NY	Falconer-Salamanca 115kV	NM-NG
183	Invenergy Wind, LLC	Buffalo Rd. Wind Farm II	3/28/05	165	Wyoming, NY	Towns of Orangeville and W	NM-NG
184	Invenergy Wind, LLC	Ripley Hill	3/28/05	75.9	Onondaga, NY	Town of Spafford	NYSEG/NM-NG
186	Community Energy	Jordanville Wind	4/1/05	150	Herkimer, NY	Porter-Rotterdam 230kV	NM-NG
187	NY Windpower, LLC	North Slope Wind	4/5/05	109.5	Clinton, NY	Willis-Plattsburgh 230kV	NYPA
*188	NY Windpower, LLC	Orangeville Wind	4/5/05	96	Wyoming, NY		
*189	PPM Energy, Inc.	Clayton Wind	4/8/05	132	Jefferson, NY		NM-NG
*190	PPM Energy, Inc.	Mixer Road Wind	4/8/05	66	Jefferson, NY		NM-NG

iii. Transmission Build

FUTURE TRANSMISSION FACILITIES AS OF JANUARY 1, 2005

LIST OF PROPOSED BULK POWER LINES

Line Owner	Terminals		Line Length miles *	Expected Service Date/Yr Prior to	**	Nominal Voltage in kV Operating	Design
Merchant							
PSEG	Bergen (New Station, NJ)	W. 49th Street	7.500	2006		345	345
Atlantic Energy Partners	Sayerville (New Station, NJ)	W. 49th Street	36.000	2006		250	dc
PG&E	Liberty (Linden, NJ)	Goethals	0.620	2006		230	230
Atlantic Energy Neptune	Duffy Ave Convertor Station	PJM	65.000	2007		500	500
Transmission Owner							
ConEd***	Dunwoodie	Sherman Creek	7.8	2005	W	138	138
LIPA (4)	Riverhead	Canal(New)	16.400	2005	S	138	138
LIPA	East Garden City	New Superconductor Substation	0.3788	2006	S	138	138
LIPA (5)	Northport	Narwalk Harbor	11	2006	S	138	138
ConEd****	Mott Haven	Dunwoodie	9.989	2007	S	345	345
ConEd****	Mott Haven	Rainey	4.083	2007	S	345	345
ConEd	Sprain Brook	Sherman Creek	10	2007	S	345	345
LIPA	Newbridge Rd	East Garden City	4	2007	S	138	138
LIPA	Newbridge Rd	Ruland Rd	9.1	2007	S	138	138
LIPA	Duffy Ave Convertor Station	Newbridge Rd 345kv	1.7	2007	S	345	345
LIPA	Newbridge Rd 345kv	Newbridge Rd 138kv	-	2007	S	-	-
LIPA	Holtsville GT	Brentwood	12.4	2007	S	138	138
LIPA (4)	Brentwood	Pilgrim	4.6	2007	S	138	138
RGE***	Station 80	Station 82/Mortimer	3.500	2007/2008	W	115	115
RGE***	Station 80	Station 82/Mortimer	3.500	2007/2008	W	115	115
RGE***	Station 82	Station 67	2.400	2007/2008	W	115	115
RGE***	Station 80	Station 67	5.900	2007/2008	W	115	115
RGE***	Station 82	Station 48	9.500	2007/2008	W	115	115
RGE	Station 48	Station 7	7.500	2007/2008	W	115	115
RGE	Station 121	Station 230	5.700	2007/2008	W	115	115
RGE	Station 80	Station 80	xfrm	2007/2008	W	345/115	345/115
LIPA (6)	Sterling	Off Shore Wind Farm	10.15	2008	S	138	138
LIPA	Riverhead	Canal	16.400	2010	S	138	138
CHGE	Hurley Ave	Saugerties	11.11	2011	W	115	115
CHGE	Pleasant Valley	Knapps Corners	17.7	2011	W	115	115
CHGE	Saugerties	North Catskill	12.25	2012	W	115	115
O&R***	Ramapo	Tallman	3.240	2007	S	138	138
O&R***	Tallman	Burns	6.080	2007	S	138	138

(6) LIPA owns 6.78 miles of the circuit
(5) Cable replacement; LIPA owns 50% of the NUSCO cable
(4) 138 kv operation as opposed to previous 69 kv operation
**** Tapping of Existing Circuit
*** Reconductoring of Existing Line
** S = Summer Peak Period W = Winter Peak Period

iv. Resource Adequacy

LOAD AND CAPACITY SCHEDULE

NEW YORK CONTROL AREA

	KILOWATTS										
SUMMER CAPABILITY	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Steam Turbine (Oil)	1649200	1649200	1649200	1649200	1649200	1649200	1649200	1649200	1649200	1649200	1649200
Steam Turbine (Oil & Gas)	9240900	9073700	9073700	9073700	8119900	8119900	8119900	8119900	8119900	8119900	8119900
Steam Turbine (Gas)	1066600	1066600	1066600	1066600	1066600	1066600	1066600	1066600	1066600	1066600	1066600
Steam Turbine (Coal)	3596900	3596900	3596900	3241600	2829600	2829600	2829600	2829600	2829600	2829600	2829600
Steam Turbine (Wood)	38800	38800	38800	38800	38800	38800	38800	38800	38800	38800	38800
Steam Turbine (Refuse)	263716	263716	263716	263716	263716	263716	263716	263716	263716	263716	263716
Steam (PWR Nuclear)	2469500	2543500	2543500	2638500	2638500	2638500	2638500	2638500	2638500	2638500	2638500
Steam (BWR Nuclear)	2610000	2610000	2610000	2610000	2610000	2610000	2610000	2610000	2610000	2610000	2610000
Pumped Storage Hydro	1288700	1408700	1408700	1408700	1408700	1408700	1408700	1408700	1408700	1408700	1408700
Internal Combustion	118582	118582	118582	118582	118582	118582	118582	118582	118582	118582	118582
Conventional Hydro	4487984	4487984	4487984	4487984	4487984	4487984	4487984	4487984	4487984	4487984	4487984
Combined Cycle	5843504	7041304	8041304	8041304	8041304	8041304	8041304	8041304	8041304	8041304	8041304
Jet Engine (Oil)	526800	526800	526800	526800	526800	526800	526800	526800	526800	526800	526800
Jet Engine (Gas & Oil)	172600	172600	172600	172600	172600	172600	172600	172600	172600	172600	172600
Combustion Turbine (Oil)	1414100	1414100	1414100	1414100	1414100	1414100	1414100	1414100	1414100	1414100	1414100
Combustion Turbine (Oil & Gas	1428000	1428000	1428000	1428000	1428000	1428000	1428000	1428000	1428000	1428000	1428000
Combustion Turbine (Gas)	1284400	1284400	1284400	1284400	1284400	1284400	1284400	1284400	1284400	1284400	1284400
Wind	46647	46647	46647	46647	46647	46647	46647	46647	46647	46647	46647
Other	680	680	680	680	680	680	680	680	680	680	680
Special Case Resources - SCR	975000	975000	975000	975000	975000	975000	975000	975000	975000	975000	975000
Additions	1197800	1000000	0	0	0	0	0	0	0	0	0
Reratings	194000	0	95000	0	0	0	0	0	0	0	0
Retirements	-167200	0	-355300	-1365800	0	0	0	0	0	0	0
:A RESOURCE CAPABILITY	39747213	40747213	40486913	39121113	39121113	39121113	39121113	39121113	39121113	39121113	39121113
Purchases(1)	80000	80000	80000	0	0	0	0	0	0	0	0
Sales(1)	-305000	-305000	-305000	-305000	-305000	-298000	-298000	-298000	-298000	-298000	-298000
AL RESOURCE CAPABILITY	39522213	40522213	40261913	38816113	38816113	38823113	38823113	38823113	38823113	38823113	38823113
BASE FORECAST											
Peak Load	31960000	32400000	32840000	33330000	33770000	34200000	34580000	34900000	35180000	35420000	35670000
Resource Capability	39522213	40522213	40261913	38816113	38816113	38823113	38823113	38823113	38823113	38823113	38823113
Required Capability	37712800	38232000	38751200	39329400	39848600	40356000	40804400	41182000	41512400	41795600	42090600
Actual Reserve KW	7562213	8122213	7421913	5486113	5046113	4623113	4243113	3923113	3643113	3403113	3153113
Reserve Requirement	5752800	5832000	5911200	5999400	6078600	6156000	6224400	6282000	6332400	6375600	6420600
Reserve Margin %	23.66	25.07	22.60	16.46	14.94	13.52	12.27	11.24	10.36	9.61	8.84
Proposed Resource Additions (	0	324500	2304100	4394100	4974100	5338800	5878800	5517800	5517800	5517800	5517800
Adjusted Reserve Margin	23.66	26.07	29.62	29.64	29.67	29.13	29.27	27.05	26.04	25.19	24.31

(1) - Purchases & Sales are with neighboring Control Areas.

(2) - Proposed Resource Additions - Includes all generating projects that are not under construction but have met milestone requirements to qualify for inclusion in a class year. Only net capacity increases are included.

(3) - Special Case Resources (SCR) are loads capable of being interrupted upon demand and distributed generators that are not visible to the ISO's Market Information System and that are subject to special rules in order to participate as Installed Capacity suppliers.

As of April 1, 2005

RERATINGS

OWNER / OPERATOR	STATION	UNIT	ZONE	DATE	CAPABILITY (kW) SUMMER	WINTER	REASON FOR RERATING
Entergy	Indian Point 2		ROS	6/1/2005	36000	36000	Uprate
Entergy	Indian Point 3		ROS	6/1/2005	38000	38000	Uprate
NYPA	Blenheim Gilboa		ROS	6/2/2005	30000	30000	Plant Life Extension
NYPA	Blenheim Gilboa		ROS	6/2/2005	30000	30000	Plant Life Extension
NYPA	Blenheim Gilboa		ROS	6/2/2005	30000	30000	Plant Life Extension
NYPA	Blenheim Gilboa		ROS	6/2/2005	30000	30000	Plant Life Extension
Constellation	Ginna		ROS	11/1/2006	95000	95000	Uprate
					289000	289000	

RETIREMENTS

OWNER / OPERATOR	STATION	UNIT	ZONE	DATE	CAPABILITY (kW) SUMMER	WINTER	REASON FOR RETIREMENT
<u>Scheduled Retirements with New Projects</u>							
Consolidated Edison Company of NY, Inc.	Waterside 6,8,9		J	7/1/2005	167200	167800	Station Repowering
New York Power Authority	Poletti 1 *		J	2/1/2008	885300	885700	Station Replacement
Reliant Energy NY	Astoria 2		J	7/1/2010	175300	181300	Station Repowering
Reliant Energy NY	Astoria 3		J	9/1/2011	361000	372400	Station Repowering
PSEG Power NY	Albany 1,2,3,4 **		ROS	3/1/2005	312300	364600	Station Replacement
<u>Scheduled Retirements</u>							
NRG Power, Inc.	Huntley 63,64 **		ROS	11/1/2005	60600	96800	Environmental Restrictions
NRG Power, Inc.	Huntley 65,66		ROS	11/1/2006	166800	170000	Environmental Restrictions
Rochester Gas and Electric Corporation	Russell Station		ROS	12/1/2007	238000	245000	Environmental Restrictions
<u>Planned Retirements</u>							
Mirant Corporation	Lovett 5		ROS	6/1/2007	188500	189700	Environmental Restrictions
Mirant Corporation	Lovett 3		ROS	6/1/2008	68500	68500	Environmental Restrictions
Mirant Corporation	Lovett 4		ROS	6/1/2008	174000	175500	Environmental Restrictions
					2797500	2917300	

*** Unit can remain in service for two years beyond scheduled retirement date, if needed to meet reliability requirements.**

**** Units have been netted out of Existing Generating Capacity - Table III-2.**

PJM

a. Summary of Most Recent Plans

Table 1: Currently Approved PJM Regional Transmission Expansion Plan (RTEP)

Plan Components *	Cost *
Baseline Reinforcements	$1,327 M
Generation Interconnection and Merchant Transmission Interconnection Network Upgrades and Direct Connection for Queues A through L	$ 533 M
TOTAL RTEP *	$1,860 M

(* NOTE: RTEP as approved by the PJM Board of Managers – December 7, 2005 Meeting.)

Baseline Reinforcements

The first step in each cycle of the Regional Transmission Expansion Planning Process is an evaluation of the "baseline" system, i.e. the transmission system without any of the generation interconnection requests included in the current planning cycle. This baseline analysis determines the compliance of the existing system with reliability criteria and standards. The cost of transmission upgrades to mitigate such criteria violations are the responsibility of the PJM transmission owners.

PJM establishes a baseline for a five-year period from which the need and responsibility for transmission system enhancements can be determined. PJM performs a comprehensive load flow analysis of the ability of the grid to meet reliability standards, taking into account forecasted firm loads, firm imports and exports to neighboring systems, existing generation and transmission assets, and anticipated new generation and transmission assets.

The baseline reliability assessment identifies areas where the planned system is not in compliance with applicable NERC and regional reliability council (MAAC, ECAR, MAIN or SERC) standards, nuclear plant licensee requirements and PJM reliability standards. The baseline assessment develops and recommends enhancement plans to achieve compliance.

Generation and Merchant Transmission Interconnection RTEP Enhancements

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of Regional Transmission Organizations. A key part of this regional planning protocol is the evaluation of generation and merchant transmission interconnection requests. Geographically clustered projects within each time-based queue are evaluated against a baseline benchmark set of studies in order to establish project-specific system enhancements, separate from general network upgrades suggested by the results of baseline analyses themselves.

Since the inception of PJM's open, non-discriminatory planning process in 1997, more than 144,000 MW of new generation requests have been submitted to PJM's interconnection queues. To date, the system enhancements planned by PJM have accommodated over 16,400 MW of new generation, representing over 130 projects. These generation additions enhance system reliability, supply adequacy and competitive markets for PJM's market participants and the customers they serve.

Economic Planning

As part of the June 8, 2005 RTEP, seven Economic Planning studies have been completed for congested facilities for which the Market Window has closed and for which no market solutions were proposed. Six of these situations involved the determination of whether previously identified RTEP reliability based Network Upgrades would mitigate congested facilities. The studies indicated that these Network Upgrades would realize a total annual reduction of unhedgeable congestion of approximately $200 million. The one remaining Economic Planning study revealed that the cost of the Network Upgrade required to mitigate the congestion was 5 times greater than the congestion savings and, therefore, the Network Upgrade was not recommended.

Generator Project Withdrawals

As part of the June 8, 2005 Plan, approximately $20 M of attachment facilities and network upgrades have been eliminated from the plan based on the withdrawal of 10 proposed generation interconnection projects from previous Queues. The withdrawal of these projects and the associated impacts on all projects through Queue L have been included in this analysis.

Major Enhancements

By way of example, the following map displays where major RTEP-identified enhancements are located. The table which follows the map provides some basic background information on each project as of June 8, 2005.

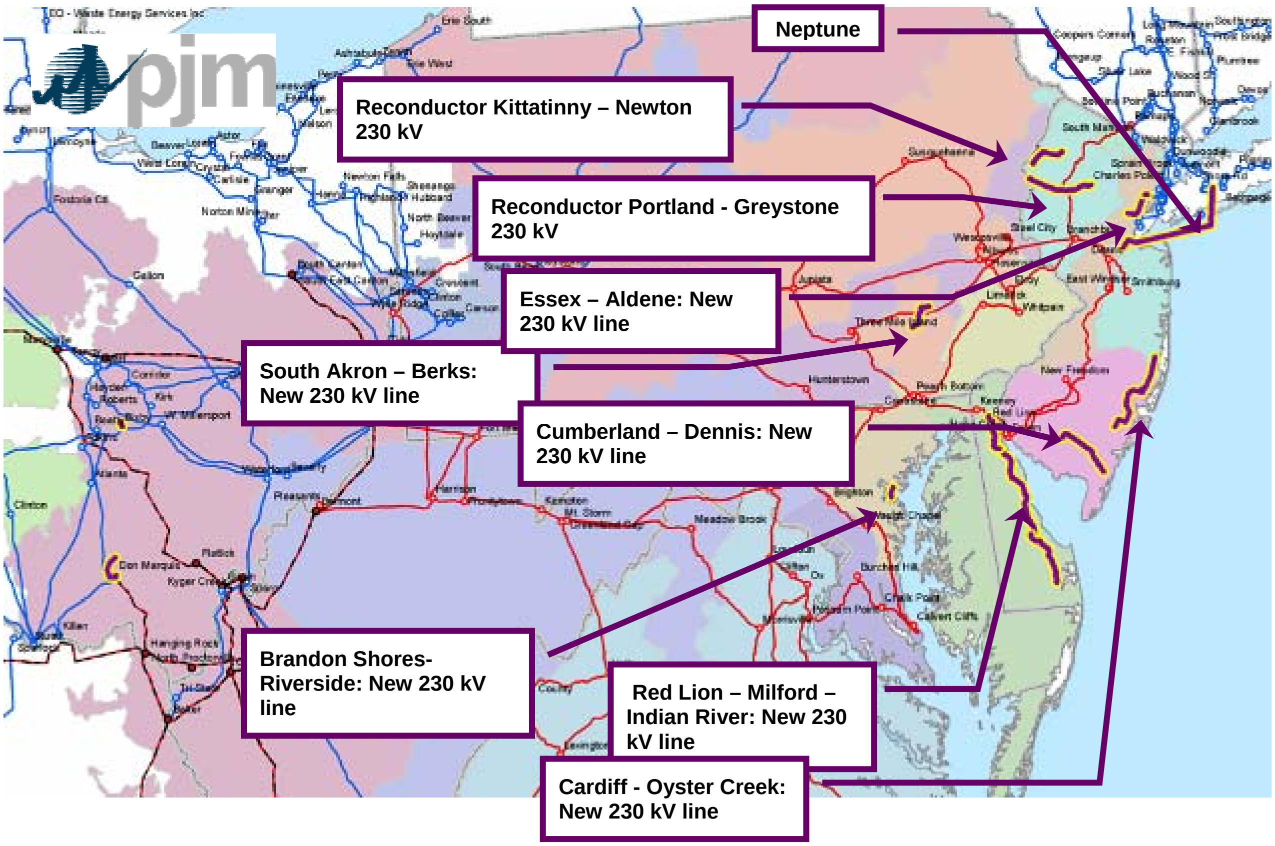


Table 2: PJM Major Transmission Enhancements as of June 8, 2005

Enhancement	RTEP Upgrade Type	Cost (Millions)	Expected In-service Date
Neptune Direct Current Project --- new transmission line	Merchant transmission proposal	n/a	6/2007
Kittatinny-Newton 230kV Line --- reconductoring existing line	Baseline upgrade for reliability.	$ 20	6/2007
Portland-Greystone 230kV Line --- reconductoring existing line	Baseline upgrade for reliability.	$ 20	6/2008
Essex-Aldene 230kV --- New transmission line	Baseline upgrade for reliability.	$ 40	12/2006
South Akron-Berks 230kV --- new transmission line	Baseline upgrade for reliability.	$ 42	6/2008
Cumberland-Dennis 230kV --- new transmission line	Baseline upgrade for reliability.	$ 16.1	12/2007
Brandon Shores-Riverside --- new transmission line	Baseline upgrade for reliability	$ 7	1/2007
Red Lion-Milford-Indian River 230kV --- new transmission line	Baseline upgrade for reliability	$ 58	6/2006
Cardiff-Oyster Creek 230kV --- new transmission line	Baseline upgrade for reliability	$ 58	7/2005

b. Planning Issues

PJM continues to provide a reliable electrical grid to ensure that its members are provided the greatest opportunity to establish and grow revenue streams for their respective business organizations. Providing these opportunities necessarily dictates that PJM's RTEP Process not remain static. Rather, PJM has already embarked on a number of organizational work plan initiatives to ensure that the reliability, market, business and regulatory needs of all constituencies continue to be met:

- Reliability Pricing Model (RPM)
- Long Term Planning Horizon / Planning to Support Competitive Markets
- Develop Innovative Business Models for Transmission Investment

These value-added initiatives will enhance members' diverse RTO business interests. That value will be derived from PJM's RTEP Process adaptability in the face of these emerging challenges.

<u>Reliability Pricing Model</u>

PJM is proposing a new approach for a generation capacity market that is called the Reliability Pricing Model. This Model coordinates the price paid for generation capacity with overall system reliability requirements. The Reliability Pricing Model provides a mechanism for generation solutions, transmission solutions and Demand Response solutions to directly compete in a four-year forward auction to satisfy system reliability requirements. Thus, the Reliability Pricing Model will provide incentives for appropriate investment to respond to the relevant reliability-related factors. It also provides a mechanism for demand response to directly compete in the forward capacity market while preserving the ability for shorter term demand response to offset Load obligation.

The proposed Reliability Pricing Model would use marginal pricing to set prices based on supply offers, capacity obligations, operational reliability and locational constraints factors. Assigning locational value to capacity is necessary to send clear and proper investment signals to capacity developers and is intended to ensure that generation development addresses transmission issues as well.

Evaluation of capacity requirements and value is highly dependent on appropriate planning analysis. More intensive and accurate data input will be required to perform the complex planning analysis that is needed to determine the locational value for capacity. The growth and development of the Electricity Market are significant drivers for the need to develop a reliability based capacity pricing model. Thus, Market Operation and Capacity Planning must be synchronized. Load forecasts are a fundamental component of the planning process to evaluate capacity requirements and the Load forecasting Initiative will provide a key input to the Reliability Pricing Model.

Among the reliability issues addressed by the Reliability Pricing Model are:

- Locational capacity requirements – Assigning locational value to capacity ensures that generation development is consistent with developing transmission issues and can also create incentive for demand response products
- Operational reliability – Generator characteristics such as dispatchable range, quick start capability and cycling capability directly affect operational reliability. The Reliability Pricing Model considers these factors and provides greater compensation for generators with more desirable operating characteristics.
- Fuel diversity – Although the Reliability Pricing Model does not specifically include fuel-type issues, it does include constraints related to generation operating characteristics. It ensures there is sufficient flexibility in the generation supply and, for example, avoids overdependence on any one fuel. In particular, the new model can help ensure diversity between base load and peaking generation.
- Reliability must run – The need to require certain generators to operate because of a local transmission reliability problem raises market power concerns. Including transmission constraints in the Reliability Pricing auction can incent solutions to the reliability problem through direct competition which will produce a transparent price that reflects the cost of preserving reliability. The four-year forward auction will reduce or eliminate the need to depend on individual Reliability Must run contracts because the costs of preserving local generation will be included in the auction clearing price. This approach significantly reduces market power issues by allowing new generation, transmission upgrades and new demand response to compete in a four-year forward auction with existing resources.

The concept behind the Reliability Pricing approach is to coordinate the price paid to generation capacity with overall system reliability requirements. This concept emphasizes that overall system reliability requirements extend beyond simply measuring system-wide installed generation reserve. The Reliability Pricing approach is designed to incorporate operational reliability metrics into the Reliability Pricing algorithm such that each generator will be paid a price for capacity that is consistent with its contribution to the reliability objective. The result of this approach is that each generator may be paid a different price for capacity. This results in more targeted compensation to the generation that has better contributions to reliability metrics.

PJM anticipates that the Reliability Pricing Model will provide appropriate signals to generation developers to encourage the installation of new generation projects in appropriate amounts, types and locations to meet reliability targets. If so, then the signals provided by the Market will achieve the desired goals. PJM has filed the Reliability Pricing Model with the FERC.

Long-Term Planning Horizon / Planning to Support Competitive Markets

Over the next ten years, PJM's enhancements to existing processes will build on an existing solid RTEP foundation to ensure that Transmission Expansion Plans continue to meet or exceed region-appropriate reliability criteria.

PJM's planning processes have always included 'what-if' Scenario Planning as a means to assess possible system reaction to specific system disturbances and events. Over the last 20 years, and indeed for many more before, these Scenario Planning studies largely took the form of long-range five and ten-year load growth based studies and maximum credible disturbance scenario studies. More recently, industry deregulation has revealed 'new' potential system scenarios whose outcome, if they arise, could have negative impacts on system reliability from both an infrastructure integrity perspective and from a load-serving capability perspective.

1. Generation Retirement

   Generator retirements can potentially lead to reliability issues. PJM adopted a retirement policy on October 21, 2004 in order to provide an orderly process to review the proposed retirement of generating units. Under the policy, PJM determines whether a unit can retire when requested or will be needed to remain in service for some period of time to allow completion of transmission-system changes to maintain system reliability. The process provides compensation to generation owners if their units are required to defer retirement. In the last two years, PJM has received requests to retire a number of generating units. The retirement of a generating unit may pose concerns about transmission-system reliability, even though, overall, the PJM system has sufficient generation. Under the policy, generation owners provide 90-days' notice of a proposed unit retirement. PJM would determine whether a reliability concern exists and identify any required transmission upgrades to ensure system reliability following the unit's retirement.

   If no reliability concerns are identified, the unit can be retired. If reliability concerns are identified, the unit would be requested to continue operating until completion of the identified system upgrades. The owner could apply to the FERC for a cost-of-service rate to recover the entire cost of operating the unit until its deferred retirement. Or, the owner could receive compensation through a formula rate in the PJM tariff for costs it could avoid by retiring the unit. The latter alternative is expected to be a more expedited procedure. The cost of the compensation would be allocated as an additional transmission charge to the appropriate transmission zones.

From an RTEP perspective, Scenario Planning for generator retirements will include “what-if” analyses that look into the future. And, based on unit characteristics – fuel type, location, size, age, etc - for units which have recently retired, PJM will perform analyses that consider retirement of remaining units that exhibit similar characteristics. Given (1) the results of such analyses, (2) the short lead time under which unit owners only need to notify PJM of imminent retirements; and (3) the longer lead times to implement transmission enhancements, scenario planning gives PJM the opportunity to consider plans in advance to mitigate any potential reliability problems such retirements might cause.

PJM has already begun to integrate its analytical procedures to accommodate the provisions of the generator retirement policy. As the policy is refined and PJM gains specific retirement case experience, PJM’s RTEP processes will evolve as well to accommodate issues as they arise.

2. Fuel Adequacy and Availability

   Fuel adequacy and availability scenario planning is not new to PJM either. In decades past, PJM performed studies as necessary to address fuel disruption scenarios such as those which could have potentially arisen out of coal strikes. In addition, the longer term impacts of various fuel cost increases have also been reflected in ongoing power flow base case development. When integrated through power flow economic dispatch, the impacts of specific fuel cost changes on power system transmission flows can be assessed.

3. Aging Infrastructure

   Ongoing processes to address the aging infrastructure of transmission facilities in the PJM footprint must necessarily be integrated into PJM’s RTEP. This integrated approach will ensure that longer RTEP analytical processes address risk-ranked aging infrastructure, initially for 500kV transformer units and later for 345 kV and 230 kV transformer units as well as circuit breakers, GSUs and other large infrastructure. PJM’s potential exposure to the catastrophic loss of such facilities will be assessed on an ongoing basis.

4. Ongoing ‘future studies’

   While all scenario planning studies encompass a ‘future’ aspect to them, such studies must also specifically address the potential risk to PJM system integrity and supply adequacy from the perspective of anticipated and unanticipated load growth, capacity growth scenarios and maximum credible disturbances.

PJM’s RTEP process is now expanding to incorporate the scenarios analyses described above, and indeed others, over the next ten years. In 2006, PJM will expand the planning horizon for its RTEP from five years to 15 years into the future. Extending the planning horizon allows better planning both for reliability improvements and for upgrades that make sure the electric grid best supports economic sales of power around the PJM region.

c. Statistics

i. Growth Statistics

PJM's load growth statistics are presented as part of PJM's Resource Adequacy statistics, found in **Section c. iv**, below.

ii. Interconnection Queue Statistics

Since the inception of PJM's open, non-discriminatory planning process in 1997, more than 145,000 MW of new generation requests have been received in PJM's interconnection queues through June 21, 2005. System enhancements planned by PJM have accommodated over 16,400 MW of new generation, representing over 130 projects. More detailed information can be found in Table 3 and Table 4, below. The generation additions these numbers represent enhance system reliability, supply adequacy and competitive markets for PJM's market participants and the customers they serve

Table 3: Megawatt Summary by Queue – June 21, 2005

Queue	Active	In-service	Under Construction	Withdrawn	TOTAL Requests (MW)
A	0	7,653	1,259	18,145	27,057
B	0	4,531	7	15,882	20,420
C	47	27	587	3,954	4,615
D	0	716	0	7,603	8,319
E	0	795	0	17,637	18,432
F	0	52	0	3,093	3,145
G	1,795	454	32	21,293	23,574
H	400	143	160	8,422	9,125
I	70	72	8	4,863	5,013
J	200	14	22	707	943
K	208	251	323	2,033	2,815
L	1,080	11	27	3,143	4,261
M	1,917	48	90	2,585	4,640
N	8,279	1,667	0	411	10,357
O	3,027	0	0	0	3,027
TOTAL MW	17,022	16,435	2,514	109,771	145,742

Table 4: Number of Projects per Queue – June 21, 2005

Queue	Active	In-service	Under Construction	Withdrawn	TOTAL Requests
A	0	27	1	34	**62**
B	0	20	0	41	**61**
C	1	2	2	19	**24**
D	0	13	0	22	**35**
E	0	8	0	38	**46**
F	0	3	0	7	**10**
G	4	19	0	53	**76**
H	2	8	2	24	**36**
I	2	5	1	16	**24**
J	1	2	1	7	**11**
K	7	10	3	13	**33**
L	8	5	2	13	**28**
M	12	4	1	8	**25**
N	40	6	0	6	**52**
O	29	1	0	0	**30**
TOTAL	**106**	**133**	**13**	**301**	**553**

iii. Transmission Built Statistics

Between 1994 and June 8, 2005, baseline upgrades totaling $671 Million have been approved by the PJM Board for the purpose of ensuring that PJM meets defined reliability criteria. An additional $446 Million of upgrades have been authorized to interconnect merchant generation and transmission projects to the PJM system and to upgrade transmission system elements affected by the interconnection of those projects.

With further PJM Board approvals as of December 7, 2005, the total amount approved for baseline upgrades is $1,327 Million and the total amount approved for interconnection of merchant generation and transmission projects is $533 Million.

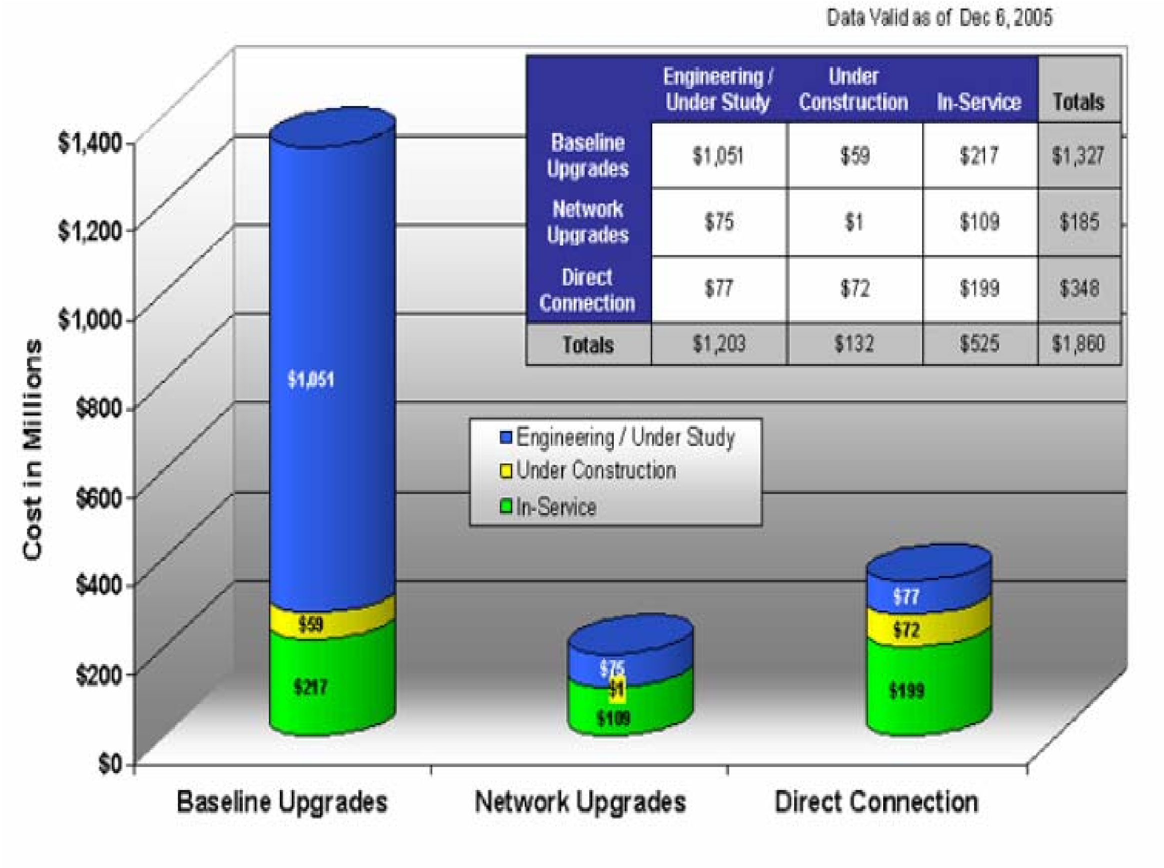
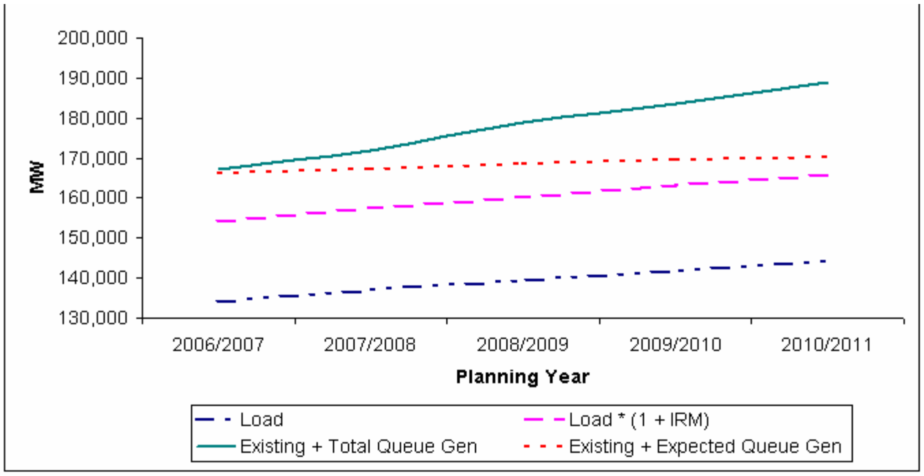


Figure 1: Cost Breakdown in RTEP by Status and Millions

iv. Resource Adequacy

PJM's three Reliability Assurance Agreements (RAAs) – one each for the Mid-Atlantic, Western and Southern regions - are intended to ensure that adequate Capacity Resources will be planned and made available to provide reliable service to loads within PJM, to assist other Load Serving Entities during emergencies and to coordinate planning of Capacity Resources consistent with established Reliability Principles and Standards and the development of a robust competitive marketplace.

The chart below displays the overall PJM RTO **load forecasts**, status of resources and PJM's forecasted reserve margin. More specifically, Forecasted Summer Peak Net Internal Demand (including the integration of Dominion in 2005) is expected to grow at an annualized RTO rate of 1.9%.



PJM RTO - 10/11/2005

	A	B	C	D	E	F	G	H	I
Planning Year	Forecasted Summer Peak Net Internal Demand	Forecasted Peak Net Internal Demand + Reserve Requirement	Existing Installed Capacity as of 10/11/2005	Total Interconnection Queue Generation by June 1st	Expected Interconnection Generation Additions by June 1st	Announced Retirements	Existing + Total Interconnection Queue Generation	Existing + Expected New Generation Additions	Summer Peak Forecasted Reserve Margin %
2006/2007	134,104	154,220	164,597	2,497	1,579	0	167,094	166,176	23.9
2007/2008	136,896	157,430	164,597	4,865	929	0	171,959	167,105	22.1
2008/2009	139,329	160,228	164,597	7,012	1,365	727	178,971	168,470	20.9
2009/2010	141,793	163,062	164,597	4,754	893	836	183,725	169,363	19.4
2010/2011	144,144	165,766	164,597	5,335	800	0	189,060	170,163	18.1

Column A: PJM Total Demand - Active Load Management. Forecast is calculated as a diversified sum of zonal forecasts.
Column B: Column A multiplied by the Reserve Requirement of 1.15
Column C: Installed Capacity as of 10/11/2005. This number represents "iron-in-the-ground" inside of the PJM electrical territory. This number excludes external sales/purchases and does not necessarily represent generation controlled by PJM.
Column D: For planning year 2006/2007, the value in Column D represents the Queue Generation from 10/11/2005 to 5/31/2006
– For all other years, the applicable time period is from June 1st of the first year listed to May 31st of the second year listed
Column E: Queue Generation * Commercial Probability (by project status)
Column F: Announced Future Generator Retirements
Column G: Existing Installed Capacity + Total Queue Generation - Announced Retirements
Column H: Existing Installed Capacity + Expected Queue Generation - Announced Retirements
Column I: [Column H/Column A] - 1

*Each planning year row represents a snapshot of the system as of the first day of the planning year (June 1st)

Figure 2: Forecasted Reserve Margin – PJM RTO as of 10/11/2005

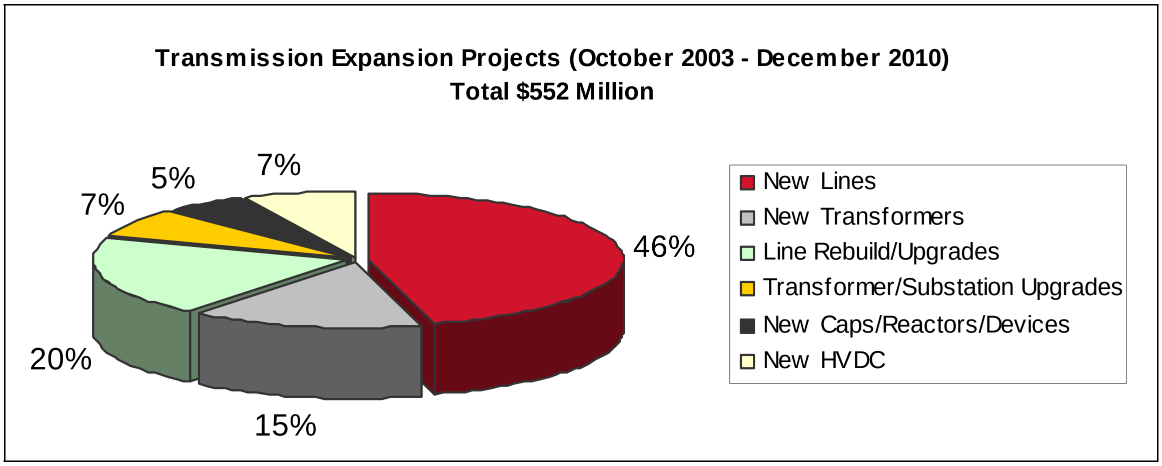
SPP

a. Summary of Most Recent Plans

SPP began the RTO expansion planning process in late 2003. The SPP RTO expansion planning process is open and collaborative using regional planning summits to present the process discuss results and collect feedback. The regional planning summits were well attended by a variety of attendees including: regulators, SPP transmission owners, transmission owners from other regions, members of the Wind Coalition, load serving entities, consulting firms and independent system operators.

Phase I report titled *SPP RTO Expansion* Plan addresses reliability violations and recommended projects to meet planning standards. The projects identified in Phase I span October 2003 through December 2010, and the SPP system requires an investment totaling $552 million. The estimated line mileage for new transmission lines for this period totaled 634 miles, while rebuilds/upgrades total 646 miles. The project types are illustrated in Figure 1.

Figure 1: Transmission Expansion Projects (October 2003 – December 2010)



The major 345 kV projects identified over the study period are as follows:

- 105 mile Finney-Lamar 345 kV line and high voltage direct current (HVDC) tie – December 2004
- Oklahoma Gas and Electric Company (OGE) Draper 345/138 kV transformer – June 2005
- American Electric Power (AEP) 14 mile Chamber Springs-Tontitown 345 kV line – June 2007
- AEP 22 mile Flint Creek-East Centerton 345 kV line – June 2010

Only 100 kV and above contingencies were assessed; as a result, the $552 million project cost does not include all 69 kV projects required to meet the planning standards. New or advanced projects identified by the SPP RTO Expansion Plan process equal $172 million of the $552 million.

A market assessment was conducted during Phase II of the SPP RTO Expansion Plan to determine potential projects for system reinforcement. Potential projects were identified from a variety of resources including stakeholder feedback, review of past transmission Line Loading Relief, refused long-term transmission reservations and suggestions from summit participants during the Planning Summit III. Thirty three projects were screened to determine the top four projects with the best cost to benefit ratio. These projects were further studied by doing complete seasonal economic runs for 2005 and 2010. The top four projects are as follows:

- Tulsa East Switching Station
- Sooner-Cleveland 345 kV line
- Rose Hill-Sooner 345 kV line
- Tolk-Potter 345 kV line

Detailed analysis of the four projects show that the projects yield a 10-year return on investment. The Sooner-Cleveland 345 kV line had the best cost to benefit ratio. Summit participants showed interest in all four projects. A proposed economic upgrade process was presented at the Regional Planning Summit IV.

At Summit IV, an Economic Modeling and Methods Task Force were formed. This task force reviews basic economic model assumptions, solution techniques, etc. and makes recommendations for improvements to future economic planning analyses.

Through the collaborative process, the SPP Transmission Working Group (TWG) has overseen the development of the plan and the draft is presented to the appropriate SPP committee structure for approval.

Currently SPP is changing the two year planning cycle to 12-months which will synchronize with the SPP Tariff Attachment Z – Aggregate study process and also the SPP Model Development Working Group (MDWG) model building effort, whereas the second cycle will utilize Models on Demand (MOD).

b. Planning Issues

Significant planning issues current facing SPP include:

- **<u>SPP RTO Expansion Plan</u>**

  The SPP Board of Directors approved the Southwest Power Pool RTO Expansion Plan (SREP) Phase I Reliability Report in April 2005. The SPP Transmission Working Group approved the final 2005-2010 SREP Report in September 2005. The SREP Phase 1 report identified 89 reliability projects with a total of $172M of investment required in 2005-2010 (in addition to TO committed projects taking the total to over $550M) as least cost solutions to meet reliability standards.

  The SREP Phase 2 analysis in 2005 investigated possible transmission expansion projects which provide economic benefits to the footprint. Per the SPP OATT, Economic Upgrades are voluntary. In this assessment, 33 potential projects were screened and a detailed analysis of 4 projects was completed. Additional, economic expansion opportunities are being evaluated to address needs in and around Kansas as well as the Panhandles of Oklahoma and Texas. These studies are posted on the www.spp.org website and details are available on the SPP eRooms.

  Mechanisms for cost recovery of reliability based upgrades are addressed in attachment J of the SPP Tariff. However, in order to move implementation of economic projects forward, the SPP Cost Allocation Working Group has been working diligently to resolve uncertainty regarding revenue credits, future reliability offsets or reallocations.

- **ERCOT/SPP Joint Study**

  SPP and ERCOT have initiated a joint study to evaluate any opportunities in the near and far-term for mutually beneficial projects in the West and Panhandle regions of Texas. SPP and ERCOT staffs are looking at the potential benefits of 4 new/expanded DC interconnections between the SPP and ERCOT systems. SPP and ERCOT have completed Phase I reliability analyses focusing on existing constraints and potential transfer capability between the regions. A Phase II economic analysis is in process and should be completed in the first quarter of 2006.

- **Project Tracking**

  To date, $177M of "Out-Of-Cycle" projects have been identified and evaluated. Out-of-Cycle means projects that are identified by the SPP transmission owners outside of the SERP reliability planning cycle. Sometimes projects are identified by SPP transmission owners for various unforeseen reasons – i.e. service to a new load, new interconnections, and system upgrades with uncertain budgeting. Out-Of-Cycle projects will not be eliminated, but ought to diminish as SPP becomes the Planning Authority. It is clear, tracking/reporting are dependent upon transmission owner communications. SPP strongly encourages the SPP transmission owners to communicate needs assessments and recommended solutions as soon as they becomes potential planning projects so that all impacts to the SPP RTO Expansion Plan can be taken into account.

- **Cost Allocation & Base Plan Funding of New Transmission Facilities** Attachment 'J' of the SPP Tariff describes the cost recovery structure for tariff funding of new SPP transmission facility upgrades. Base Plan upgrades are upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the Transmission System. Base Plan Upgrades also include upgrades required for new or changed Designated Resources. SPP recognizes the need for transmission projects that address distribution system reliability needs but are not readily quantified through traditional NERC/ERO reliability criteria. For this reason, SPP is in development of reliability guidelines beyond existing traditional reliability criteria to help determine eligibility for base plan funding in a consistent and equitable manner for all similarly situated customers within SPP.

- **Aggregate Study – SPP Tariff Attachment 'Z'**. This recently approved Attachment outlines a process used to evaluate long-term transmission service requests using an Aggregate Transmission Service Study process. The Transmission Provider will combine all long-term point-to-point and long-term designated network resource requests received during a specified period of time into a single aggregate transmission service study. Using this aggregate study process, SPP will combine all requests received during an open season to conclude an optimal expansion of the transmission system that provides the necessary ATC to accommodate all such requests at the minimum total cost. For the purposes of this Attachment Z, all Transmission Owners that are not taking Network Integration Transmission Service will be treated the same as Transmission Customers taking Network Integration Transmission Service. This attachment details: (i) cost allocation and cost recovery for Requested Upgrades; and (ii) transmission revenue credits for Requested Upgrades, Economic Upgrades, and directly assigned costs that are in excess of the Safe Harbor Cost Limit for Network Upgrades associated with new or changed Designated Resources.

- **EMMTF** The SPP Transmission Working Group (TWG) established the Economic Modeling & Methods Task Force (EMMTF) to advise and assist SPP Staff in the determination of the appropriate data, sources, models, timing, application and economic parameters to be used in the development and evaluation of economic options for the next increments of the SPP RTO Expansion Plan. Recent activities of the task force include validation of generator data and drafting of the economic planning white paper.
- **NERC Reliability Standards & Blackout Recommendations** SPP planners continue to support the results of the blackout recommendations and the new NERC/ERO Reliability Standards in response to the 2005 Federal Energy Bill.
- **Dynamic Modeling – Transition to Model On Demand (MOD)** SPP has numerous internal and external customers that require accurate Eastern Interconnection electric grid models. The current method of annual model updates does not make available to all customers the best information that is critical to decision making on grid expansion and reliability. Customers are also asked for model data information by multiple sources. Model on Demand (MOD) will provide a common place for model data providers and users to view, modify, and export their data and models.
- **Data Collection & Coordination** Data collection and coordination is a key issue at SPP where members are over burdened and often find similar requests from SPP staff Planning, Modeling and Aggregate groups. SPP is working to develop a singular means of collecting data from the SPP transmission owners for projects and mitigation solutions and ideas through a single point contact. This information will be funneled into a database from which SPP departments will strive to retrieve what they need before asking members for more information.

c. Statistics

SPP, a FERC-approved regional transmission organization (RTO), is a group of 45 members serving more than 4 million customers and covers a geographic area of 255,000 square miles containing a population of over 18 million people. In covering a wide political, philosophical, and operational spectrum, SPP's current membership consists of 13 investor owned utilities, seven municipal systems, eight generation and transmission cooperatives, two state authorities, three independent power producers and 12 power marketers. Eighteen of the 150 control areas within the North American continent are members of SPP. SPP is more than 350 electric industry employees on various organizational groups that bring together unmatched expertise to deal with tough reliability and equity issues. An administrative and technical staff of approximately 165 persons facilitates the organization's activities and services.

i. Load Growth

Through econometric modeling, the following table summarizes SPP growth rates that bound the most likely range of occurrence under normal weather conditions. The results of the 2001 forecast are also shown for comparison.

Annual Compound Forecast Growth Rates

	(%/Year 2003-2012)			(%/Year 2001-2010)		
	Low	Base	High	Low	Base	High
Peak Demand	**0.9**	**1.7**	**2.9**	**1.8**	**2.2**	**2.6**
Annual Energy	**0.8**	**1.6**	**2.7**	**1.6**	**2.0**	**2.4**

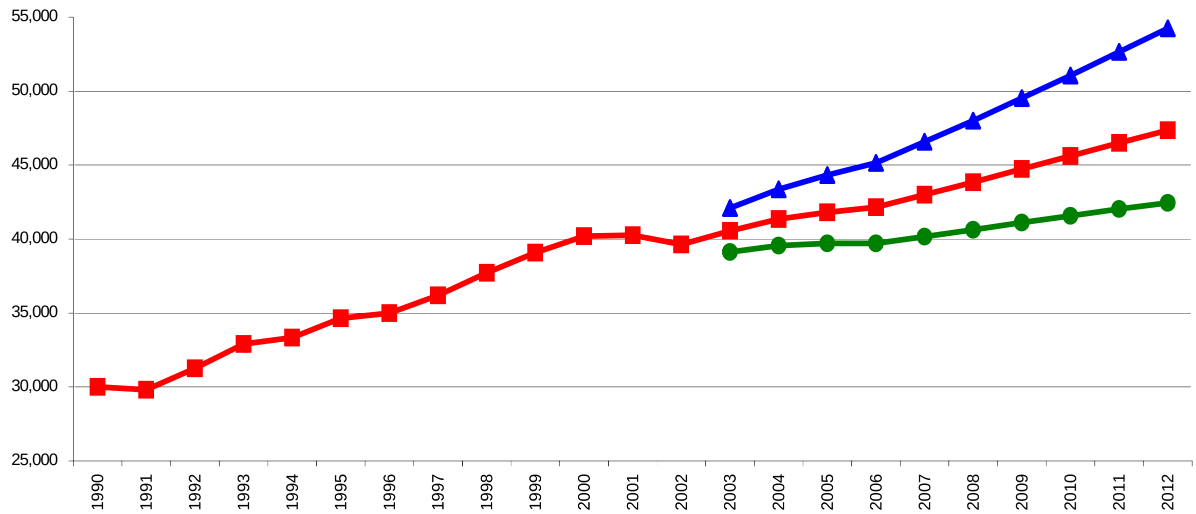


Figure 2: Bandwidth Forecast of SPP Demand (MW)

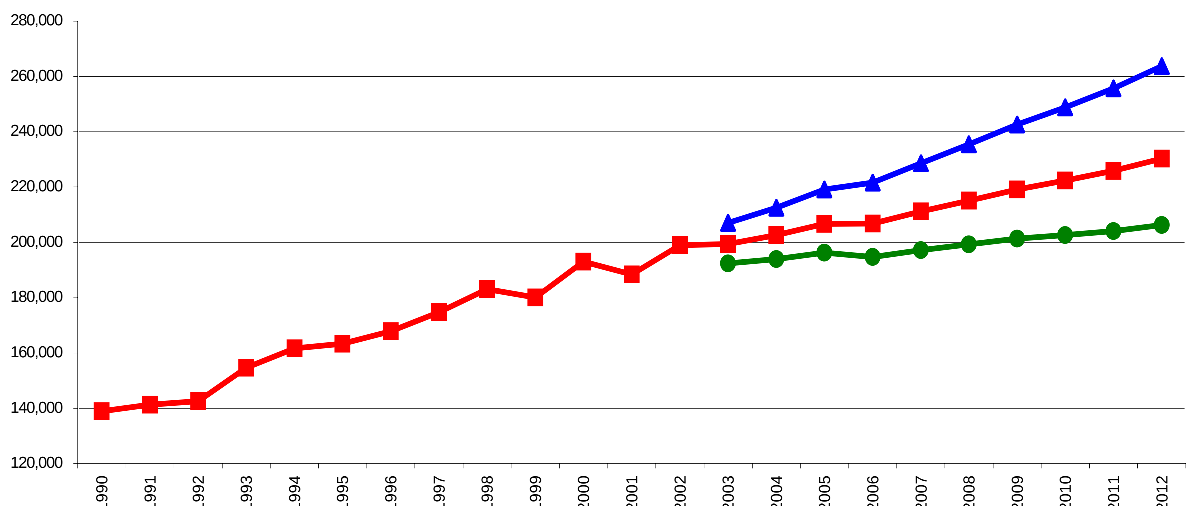


Figure 3: Bandwidth Forecast of SPP Energy (GWh)

SPP member systems continue to forecast similar growth of future demand and energy requirements. The annual compound growth rate on peak demand for the next 10 years decreased from 2.2 %/yr in 2001 to 1.7 %/yr in 2003. Actual peak demand has grown at 2.3 %/yr from 1990 to 2002. The annual compound growth rate on energy for the next 10 years decreased from 2.0 %/yr. in 2001 to 1.6 %/yr. in 2003. Actual energy has grown at 3.0 %/yr.

The econometric predictor variables applied in the 2003-2012 forecasts are similar to the ones used in the 2001-2010 forecasts. The SPP forecast growth rates for the high, low and base economic scenarios for both the 2003 and 2001 forecasts are shown on the previous page. The demand and energy growth rates for both the high and low economic scenarios have more variance from the base forecast in 2003 compared to 2001.

Two standard deviations were used for a 30-year average to account for extreme weather effects. These variables were then incorporated in the base energy forecast model in place of the normal values to generate energy bands, which represent the effects due to extreme weather. The extreme weather demand bands were derived from the extreme weather energy bands using one standard deviation from the 10-year mean load factor. Should weather extremes occur in any given year in addition to a low or high growth scenario, the bands are broadened as shown in the following figures. These weather uncertainty percentages can be applied to all economic growth scenarios.

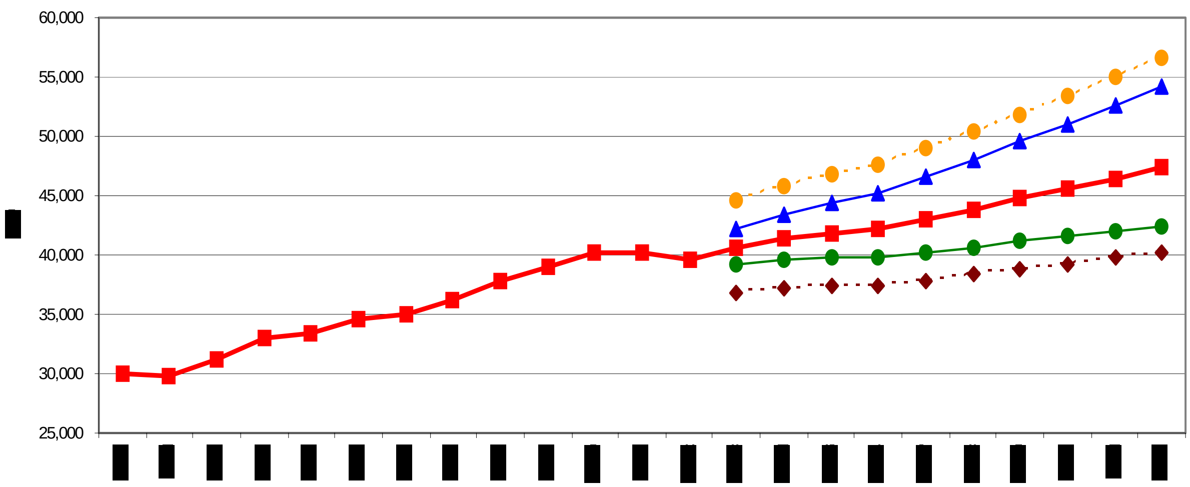


Figure 4: SPP Bandwidth Demand Forecast Economic in Weather Bands

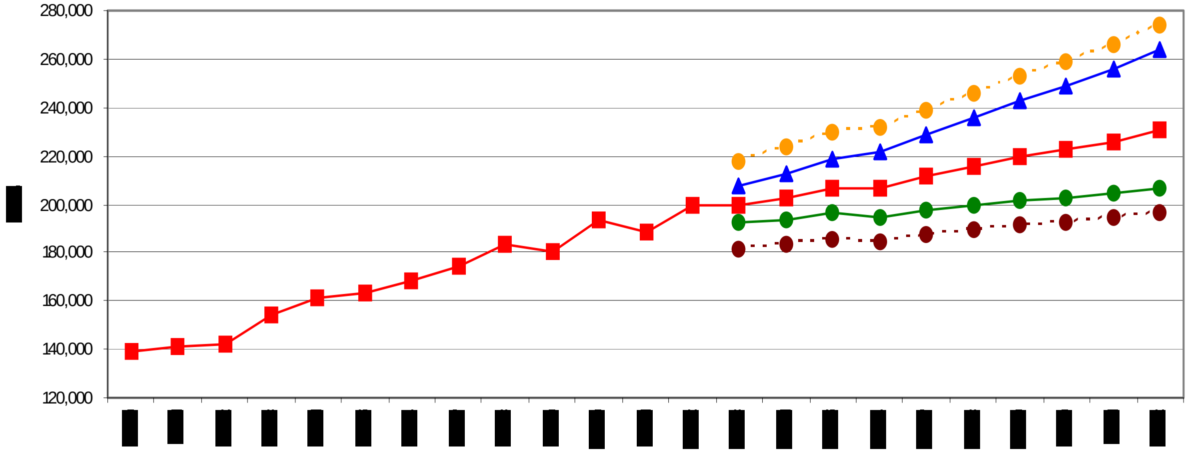


Figure 5: SPP Bandwidth Energy Forecast Economic and Weather Bands

ii. Interconnection Queue

Generation

- Number of requests = 39, representing 7,260 MW
  - Number of wind requests = 27, representing 4,833 MW
  - Number of fossil fuel requests = 12, representing 2,427 MW
- Number of requests with Interconnection Agreement pending = 10
  - Interconnection Agreements signed during 2005 = 3
- During the same period last year, there are 37 requests in process (26 wind; 11 fossil fuel) representing 9,078 MW (4,279MW wind; 4,799 MW fossil fuel)

Transmission

- Number of requests/studies = 180/104, representing 15,249 MW
- Number of non-DC tie requests/studies = 87/71, representing 6,239 MW
- There are 82 requests/26 studies for the DC ties representing 8,456 MW that cannot be processed due to impending DC tie competition.
- During the same period last year, there were 136 requests/63 studies in process, representing 18,090 MW. There were 76 request/24 studies for DC ties representing 8,072 MW that could not be processed due to impending DC tie competition.

iii. Transmission Build

Several major new transmission projects have been completed in the SPP since 2002. A 105 mile 345kV line from Finney, KS to a HVDC tie into WECC at Lamar, CO was completed during the winter of 2004. Approximately 220 miles of 345kV transmission line was built from Potter, TX to Finney, KS and a re-conductor of the 31 mile LaCygne to Stilwell 345kV line was completed in winter 2002. To mitigate existing and projected transmission constraints, a second 500/161kV transformer was added at Fort Smith, AR during the Winter of 2004. Southwestern Public Service added a new 25 mile 230 kV line from Seven Rivers-Eddy County with a 230/115 kV step down transformer at Seven Rivers in Eddy County, NM. Oklahoma Gas & Electric has added a third 345/138 kV transformer at Draper in May. SPP members have completed 76 projects in the last year amounting to $88 million of investment to expand and upgrade the existing transmission system. These upgrades have eliminated easy to fix terminal and flowgate limits that have restricted substantial transmission service in the SPP system.

iv. Resource Adequacy

SPP uses a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments are performed on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin.

The SPP capacity margin based on committed resources is expected to be 40.3% for the 2005/2006 winter, which is comparable to the calculated capacity margin from last year. This is significantly above the 12% minimum criteria for the region.

ISO/RTO REPORT III: SEAMS/BOUNDARY PLANNING ACTIVITIES

Introduction

In accordance with recent FERC-defined policies that require ISO/RTOs to develop mechanisms to address inter-regional coordination, PJM, MISO, NY-ISO, ISO-NE and TVA have initiated several efforts to implement boundary seams coordination processes as part of their individual respective planning processes. In addition, the ISO/RTOs who are not FERC jurisdictional have developed such coordination agreements. These include the following initiatives:

1. Midwest ISO and PJM Joint Operating Agreement ("JOA") – December 31, 2003
2. Northeastern ISO/RTO Planning Coordination Protocol – December 8, 2004
3. Midwest ISO, PJM Interconnection and TVA Joint Reliability Coordination Agreement – April 22, 2005
4. Memorandum of Understanding ("MOU") Among NYISO, PJM and ISO-NE to Coordinate on Natural Gas Supply Conditions Related to Generation – June 3, 2005.
5. NYISO and ISO-NE Interregional Coordination And Seams Issue Resolution Agreement ("ICA") – December 10, 2004
6. Northeastern Independent Market Operators Coordinating Committee ("NIMOCC") – June 11, 2002
7. CFE/ERCOT Interconnection Study – December 19, 2003
8. Midwest ISO and SPP JOA – December 2, 2004
9. IESO Operating and Interconnection Agreement
10. CAISO Boundary Planning Activities

Expanding inter-regional markets and system inter-operability demand coordinated integrated system assessments and planning inter-regionally. Inaction could allow unresolved reliability issues to emerge at RTO/ISO transmission interfaces. Missed opportunities to resolve reliability criteria compliance issues could result, absent such inter-regional mechanisms as those listed above to address seams issues jointly and proactively.

The balance of Section IV discusses each of these initiatives in more detail were appropriate from the perspective of the structure of the operating agreements, the associated protocols, and memorandum of understandings (MOUs). Also, the discussions will review the current state of activities and upcoming activities including timelines and deliveries for the above initiative.

1) Midwest ISO and PJM JOA – December 31, 2003

a. Structure of Operating Agreements, Protocols and MOUs

JOA Structure

On December 31, 2003, PJM and the Midwest ISO filed a Joint Operating Agreement ("JOA). The JOA governs aspects of the relationships between the Midwest ISO and PJM that affect reliability. The JOA resolves seams issues, providing measures to enhance data exchange and other communications, flowgate coordination, coordination of long-term transmission planning, and emergency procedures between the two RTOs.

Structured in three phases (Phases 0, Phase 1 and Phase 2), Phase 0 of the JOA became effective upon execution of the Agreement itself and included immediate implementation of a number of provisions to enhance interregional reliability. Many of those provisions were already underway in some manner and forum. From a planning perspective, Phase 0 has included formal implementation of information and data exchange (per Article IV) and coordinated regional transmission expansion planning (per Article IX).

Phase 1 continues the planning aspects of Phase 0. From a markets and operations perspective, Phase 1 is the period during which PJM's market-driven operations will interface with the non-market operation of the Midwest and will end when all PJM and Midwest ISO control areas on the parties' adjacent boundaries are included in LMP-based markets, at which time the Phase 2 market-to-market phase will take effect and continue in effect throughout the entire term of the JOA.

Committee Structure and Governance

Under Article IX of the JOA, the parties have established a Joint RTO Planning Committee ("JRPC") to coordinate system planning activities. Coordinated system planning includes preparation of common power system analysis models and the regular preparation of a Coordinated System Plan. These models permit power flow, short circuit and stability analyses for use in planning. The Coordinated System Plan is a final product specifying upgrades and modification necessary to efficiency and congestion management. The JRPC will facilitate communications, committee work and review by appropriate governmental authorities. The parties have also agreed to the formation of an Inter-Regional Planning Stakeholder Advisory Committee ("IPSAC) to facilitate stakeholder review and input into the development of the Coordinated System Plan.

Coordinated Regional Transmission Expansion Planning

Coordinated regional transmission expansion planning across the seams will reduce congestion on an inter-RTO basis and enhance the physical and economic efficiencies of congestion management. Under the JOA, the parties have agreed to coordinate the results of their respective transmission expansion planning processes in order to establish inter-regional planning.

The JOA specifies substantial detail about the coordinated planning process. Each party shall provide the other annually with twelve categories of detailed information. Each party continues to engage in its customary internal system planning activities as required under its respective tariff and other applicable standards, and shall prepare a planning report that documents the procedures and methodologies applicable to its plan. The coordinated process will include studies for generator and merchant transmission interconnection and long-term firm transmission reservations, and provide for the recovery of study costs. The process will culminate with the preparation of a Coordinated System Plan applicable to both Midwest ISO and PJM systems. This plan will integrate the parties' respective transmission expansion plans, resolve impacts across seams and address results of the underlying analyses. The detailed procedures for development and completion of the Coordinated System Plan assure its regular completion and updating and that stakeholders will have an appropriately high level of involvement.

Upgrade Cost Allocation

The JOA allocates two categories of upgrade costs: (a) costs within one party's borders due to generation and merchant transmission interconnection or long-term firm transmission reservations across the seams; and (b) network upgrades addressed in the Coordinated System Plan to resolve thermal or other constraints related to reliability or economic criteria (and not resulting directly from specific interconnections or reservations). Costs of upgrades under (a) will be coordinated and allocated consistent with the parties' Order 2003 compliance filings and the Commission's orders on those respective filings.

Costs of upgrades under (b) will be allocated equitably to the parties based on the nature of the constraint being resolved. The JRPC will develop procedures and standards to evaluate the parties' relative contributions to the constraint for this determination, all to be reviewed by the IPSAC. Each party will enforce the obligations to construct and own or finance transmission facilities under applicable transmission owners agreements.

b. Current State of Activities --- PJM / MISO

Under the auspices of the JRPC, generation interconnection coordination activities are in progress, including the following:

- The coordinated model is being screened for generation or merchant transmission projects that have an impact that is greater than 3% of line rating of any element in the opposing system.
- Modeling information for projects that exceed the 3% screening threshold is being exchanged.
- Potentially impacted facilities and corresponding system upgrades are being identified.
- The impacts of individual projects on all PJM & MISO facilities are being noted in the appropriate Feasibility / Impact Study.

A major part of this effort is the identification of projects "on the border" which need to be studied by the opposite party. Those projects which pass the 3% screen become the focus of fully coordinated study efforts.

c. Upcoming activities including timeline and deliverables --- PJM / MISO

The following timeline outlines upcoming activities and deliverables

- August 2005 - Develop 2011 MTEP / PJM RTEP Base case *
- September/October 2005 - Develop coordinated system plan scope and schedule review with IPSAC – September/October 2005
- 2Q, 2006 - Complete preliminary analysis and review with IPSAC
- August, 2006 - Complete first coordinated system plan
- 3Q, 2006 - Finalize analysis, report and review with IPSAC

* Notes:

"MTEP" = Midwest ISO Transmission Expansion Plan

"PJM RTEP" = PJM Regional Transmission Expansion Plan

2) Northeastern ISO/RTO Planning Coordination Protocol – December 8, 2004

a. Structure of Operating Agreements, Protocols and MOUs

Goal of the Agreement

The Northeastern ISO/RTO Planning Coordination Protocol Agreement executed by the PJM Interconnection, L.L.C. (PJM), the New York Independent System Operator (NYISO), and ISO New England (ISO-NE) documents the formal basis for coordinated plan development among the signatories. The agreement was effective upon execution by all parties as of December 8, 2004.

The Northeastern Coordinated System Plan: 2005 (NCSP 2005) issued on April 6, 2005 is the initial work product under the Coordinated Planning Protocol. This "state of the planning processes" document was prepared in anticipation of the first open stakeholder meeting to explain what is planned under the protocol and to seek stakeholder comments. The document consolidates the system assessments and plans of each of the participating control areas, highlights existing inter-regional planning activities, summarizes perceived issues and risks and identifies potential issues for future analysis. The NCSP 2005 is labeled a “Final Draft” because the Protocol stipulates that the development of a fully coordinated plan will be conducted with stakeholder input from the Interregional System Planning Advisory Committee (IPSAC) and the report serves as the basis for such a plan.

The goal of the 2006 NCSP is to provide adequate and coordinated system planning activities among the ISOs and RTOs of the northeastern United States and Canada to achieve a reliable system of generation, distributed resources, demand side management and transmission facilities. Such coordinated planning is necessary to ensure that coordinated analyses are performed to identify power system reliability concerns or other system needs and then to recommend any system upgrade requirements to mitigate those reliability concerns.

The identification of other system needs provides signals to the market to allow the market to respond. To the extent that the market responds with adequate solutions to identified system needs or solutions that mitigate identified reliability concerns, such solutions will be evaluated and included in the NCSP. Where inadequate market solutions are proposed, regulated solutions will be developed and included in the NCSP. In this way, the NCSP will identify expansions or enhancements to transmission system capability that is needed to maintain reliability, improve operational performance, and enhance the competitiveness of electricity markets in full coordination with market responses. Thus, the NCSP is intended to provide a coordinated, cost effective system development plan that identifies appropriate projects to ensure both reliability of service and a robust market.

NCSP Planning Protocol

The NCSP protocol describes the foundation for processes and procedures through which coordination of system planning activities will be implemented by the ISOs and RTOs of the northeastern United States and Canada. The protocol document maintains the primacy of the individual ISO/RTO planning responsibilities and is binding on each party's successors and assigns. The protocol is not a mandate to fully integrate planning for the entire northeastern footprint, but rather to ensure that planning is coordinated among the individual ISO/RTOs to ensure that the entire northeastern system will be operated reliably and in a manner that promotes economic competition. The activities of the parties, as defined under this protocol, will be conducted in coordination with the Regional Reliability Councils of northeastern United States and eastern Canada (NPCC and MAAC). In addition, the protocol was developed with participation from Ontario's Independent Electricity Market Operator (IMO), Hydro-Quebec (TransEnergie) and New Brunswick Power. These entities are not parties to this protocol but have accepted to participate, at their convenience, in the Data and Information Exchange process and in regional planning studies for projects that may have inter-area impact to ensure better coordination in the development of the Interconnected Power System. This could include participation in studies of Interconnection Requests and studies of Long Term Firm Transmission Service Requests. The Canadian entities are not participating in any sharing o£ the costs, as proposed under this protocol, of future system upgrades or modification.

NCSP Committee Structure

The Protocol describes the committee structure that is established to coordinate inter-area planning activities, procedures for the exchange of planning-related data and information, and the system planning analysis procedures that will be utilized by the parties. The protocol establishes:

- Inter-area Planning Stakeholder Advisory Committee
- Joint ISO/RTO Planning Committee.

The Inter-area Planning Stakeholder Advisory Committee (IPSAC) will be the primary means for providing stakeholder input for development of the NCSP. The IPSAC will review all stakeholder input and will coordinate system planning activities by all stakeholder groups. Initially, the representatives to the existing ISO/RTO planning advisory committees will comprise the membership of the IPSAC. Membership on the IPSAC is open to all stakeholders and may include the market participants within the regions of the parties, governmental agencies, regional state committees, regional reliability councils, and any other parties with an interest in the coordination of planning related to the northeastern ISO/RTOs. With respect to the development of the 2006 NCSP, the IPSAC will meet:

- Prior to the start of each cycle of the coordinated planning process to review and provide input on the assumptions and scope of analysis upon which the development of the NCSP will be based.
- At least once during the development of the NCSP to review and provide feedback on the preliminary results of the coordinated system planning analysis and to identify sensitivity analyses that may be required.
- Upon completion of the NCSP to review the final results of the system planning analysis.

A Joint ISO/RTO Planning Committee (JIPC), comprised of representatives of the staff of the parties, will coordinate actual planning activities, identifying issues related to the Inter-area planning process, and facilitating the resolution of such issues. In addition, ad hoc committees may be established to resolve specific planning coordination issues. Such ad hoc committees may include representatives of the JIPC, the affected transmission owners, and other interested stakeholders. The JIPC shall have the following responsibilities:

- Coordinate planning activities under this protocol, including the development of planning procedures, the conduct of planning analyses, and the production of the NCSP.
- Maintain a web site and required e-mail lists for the communication of information related to the coordinated planning process,

- Meet on at least a semi-annual basis to review and coordinate system planning activities,
- Support the review by any federal or provincial agency of elements of the NCSP,
- Support the review by multi-state entities, regional state committees, state, provincial, or other similarly situated entities, including the facilitation of new transmission facility additions.
- Establish working groups as necessary to provide adequate development and review of the inter-area plan. Where practical, the JIPC will utilize existing working group and committee structures in support of inter-area planning activities.

b. Current State of Activities

Study Content

The primary purpose of the NCSP planning protocol is to contribute, through coordinated planning, to the on-going reliability and the enhanced operational and economic performance of the systems of the parties. This is to be accomplished in two ways:

1. First, the parties will coordinate the evaluation, on an on-going basis, of Tariff-provided services, such as generation interconnection, to recognize the impacts that result across the seams between systems.
2. Second, the parties will produce, on a periodic basis, a Northeastern Coordinated System Plan (NCSP) that integrates 1) the system plans of the parties, 2) on-going load growth and retirements or deactivations of infrastructure, 3) market-based additions to system infrastructure, such as generation or merchant transmission projects, 4) distributed resources, such as demand side and load response programs, and 5) transmission upgrades identified, jointly, by the parties to resolve seams issues or to enhance the coordinated performance of the systems.

Each ISO/RTO region will continue to perform its individual planning analysis, as required by its tariffs and procedures and applicable reliability rules. The results of these area analyses will be included in, and form the basis for, the further studies to be performed under the 2006 NCSP. Such additional studies will focus on those proposed projects or system conditions that may have significant inter-regional implications. The goal of the 2006 NCSP is to achieve a reliable system of generation, distributed resources, demand-side management and transmission for the Northeast region. The 2006 NCSP will identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, or enhance the competitiveness of electricity markets. By so doing, it is intended that the NCSP will help ensure that sufficient regulated transmission solutions are identified in the event that market-based responses do not respond to identified needs.

All analyses performed to evaluate cross-border impacts on the system facilities of one of the parties will be based upon the criteria, guidelines, procedures, or standards applicable to those facilities. In the event that system upgrades may be needed to resolve cross-border impacts, such upgrades will be constructed according to the standards, terms, and conditions of the party on whose system the upgrade is to be constructed.

Specific Issues

An IPSAC meeting was held on June 17, 2005 to discus with stakeholders the provisions of the 2005 NCSP and to solicit input toward the development of the scope for the 2006 NCSP. Based on their knowledge and experience in planning for their respective areas, the meeting participants identified the following non-exclusive list of specific issues for inclusion in the next NCSP. The parties intend to solicit stakeholder input and comment on these and other issues during the initial implementation phase for NCSP 2006.

- Fuel Diversity – There are a number of initiatives concerning fuel diversity that have either been completed or are under way within the existing ISOs. The primary concern is due to the extensive development of natural gas-fired generation that has been installed in recent years. In recognition of this concern, the three northeastern regional grid operators (ISO-NE, NYISO and PJM) participated in a study of gas supply and delivery system capability. The grid operators also entered into a Memorandum of Understanding in June 2005 to coordinate operations and practices and share information and technology during periods of extreme cold weather and/or abnormal gas supply or delivery conditions. The MOU fosters an ongoing cooperative effort to ensure the use of available gas supply capability for reliable electric system operation. For 2006, the scope of work for fuel diversity will be to summarize the existing studies including results and conclusions of those studies and to provide a recommendation for any future fuel diversity studies.
- Resource Adequacy – Loss of Load Expectation (LOLE) analysis. The three northeastern regional grid operators (ISO-NE, NYISO and PJM) will complete a study to expand their existing resource adequacy models to include additional details from the other ISO/RTOs
- Loss of Source – Hydro-Quebec source issue – A study will be completed using a joint 2009 planning representation to determine the impacts on the ISO/RTOs of all single contingency loss of sources exceeding 1000 MW.
- 1000 MW Wheel / Ramapo – The existing agreements and operating protocols will be reviewed to determine if any changes are warranted.
- Unit Retirements – Generator retirements will be modeled in the three ISO/RTOs systems and any potential impact to reliability will be quantified. The focus will be on impacts to the 345 kV and higher systems and more localized issues will not be part of the scope of this evaluation.
- Inter-System Oscillations – The ISO/RTOs will review occurrences of inter-system oscillations since 2000 and will provide a recommendation for potential future study work in the 2007 NCSP.
- Environmental Issues – A summary will be developed of existing environmental restrictions, the timing of the restrictions and potential implications to the Northeastern generation fleet.
- Nuclear Plant Re-Licensing – A review of existing nuclear plant NRC licenses will be completed to determine potential implications to the Northeastern nuclear generation fleet.

c. Upcoming Activities Including Timeline & Deliverables

Process and Timeline

The NCSP will be a periodic comprehensive, coordinated inter area assessment and system expansion study. The JIPC will develop the scope and procedures for the 2006 NCSP which will then be reviewed with the IPSAC. The timeline schedule of activities for development of the 2006 NCSP is:

- June, 2005 - First IPSAC meeting to review 2005 Northeastern Coordinated System Plan (NCSP) and obtain stakeholder input for the 2006 NCSP.
- July, 2005 - JIPC meeting to discuss any follow up to stakeholder input from the June IPSAC meeting
- August, 2005 - Start analysis for 2006 NCSP such as base case development, etc.
- November, 2005 IPSAC meeting to review preliminary scope of work and provide updates.
- Spring, 2006 - Final Draft 2006 NCSP issued for stakeholder review.
- June, 2006 - IPSAC meeting to receive and discuss comments on final draft.
- Summer, 2006 - Issue 2006 NCSP

3) Midwest ISO, PJM Interconnection and TVA Joint Reliability Coordination Agreement – April 22, 2005

a. Structure of Operating Agreements, Protocols and MOUs

JRCA Structure

On April 22, 20005, the Midwest Independent Transmission System Operator, Inc. (Midwest ISO), PJM Interconnection (PJM) and the Tennessee Valley Authority (TVA) signed a Joint Reliability Coordination Agreement (JRCA) to provide for cooperation in the management and operation of the electric transmission grid over a major portion of the eastern United States. The Parties will establish an Operating Committee to administer the arrangements under the JRCA.

b. Current State of Activities

Reliability Coordination

The JRCA provides for actively managing the reliability of seams between the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. It provides for the comprehensive management of reliability and relief of congestion within the three power systems. To accomplish this, the parties will share critical operating information, system models and extensive planning data to ensure that all have the best information possible in their day-to-day operations. This information-sharing will enable each transmission provider to recognize and manage the effects of its operations on the adjoining systems.

The three organizations have also agreed to conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adversely affecting reliability to any organization's customers.

c. Upcoming Activities Including Timeline & Deliverables

Planning Coordination

Planning will begin in a manner consistent with Midwest ISO and PJM's respective tariffs and the laws and rules pertaining to TVA's status as a regional, non-FERC jurisdictional entity within the Eastern Interconnection. The Parties shall engage in coordinated system planning to identify expansions or enhancements to transmission system capability that may be needed to maintain reliability and/or improve operational performance. The Parties will coordinate any and all studies required to assure reliable, efficient and effective operation of the transmission systems. The timeline schedule for periodic activities to ensure planning coordination is:

- Operating Committee (OC) – An OC shall meet no less than once quarterly to address any issues associated with the JRCA that a Party may raise and to determine whether any changes to the Agreement, or procedures employed under the Agreement, would enhance reliability, efficiency or economy.
- Joint Planning Committee (JPC) – A JPC shall be formed as a subcommittee of the OC and shall meet at least semi-annually to review and coordinate transmission planning activities.
- Coordinated Regional Transmission Planning Study (CRTPS) – The JPC shall conduct a CRTPS on a regular basis. The parties shall conduct a CRTPS at least every three years. Sensitivity analyses will be performed, as required, during the off years based on a review by JPC of discrete reliability problems or operability issues that arise due to changing system conditions.
- Data and Information Exchange – Each Party shall provide the other Parties with the following data and information:

Monthly identification of interconnection requests that have been received and any long-term firm transmission services that have been approved that may impact the operation of a Party's system in a manner that affects another Party's system.

Quarterly, the status of all interconnection requests that have been identified.

Each Party acknowledges that voltage control and reactive power coordination are essential to promote reliability. At least once each calendar quarter, the Parties will exchange voltage schedules and meet and confer to identify system conditions that could impact the schedules and determine adjustments to the schedules, consistent with reliability.

4) MOU Among NYISO, PJM and ISO-NE to Coordinate on Natural Gas Supply Conditions Related to Generation - June 3, 2005

a. Structure of Operating Agreements, Protocols and MOUs

MOU Structure

On June 3, 2005, the New York Independent System Operator, Inc. (NYISO), PJM Interconnection (PJM) and ISO New England Inc. (ISO-NE) entered into a MEMORANDUM OF UNDERSTANDING (MOU) to coordinate education, communications, operations (processes and procedures) and planning on matters related to natural gas supply and delivery issues potentially or directly impacting the Parties' bulk electric power systems under extreme cold weather and/or abnormal natural gas supply or delivery conditions.

The Parties agree to establish a working committee comprised of representatives from each Party through which the work contemplated under the MOU shall be coordinated and executed. The Parties further agree to commit resources required to support agreed upon activities in a cost effective manner. While seeking to improve coordination between electric and natural gas industries, the Parties shall promote the management of natural gas and electric operations at market seams in a manner consistent with competition and consumer choice. b. Current State of Activities

Gas Supply and Delivery Coordination

Under the terms of the MOU, the Parties agree to the following:

1. Share information and technology concerning, and provide expertise and advice on, the coordination of natural gas and electric operations under extreme cold weather and/or abnormal natural gas supply or delivery conditions with the intention of building consensus positions,
2. Coordinate their electrical operations with one another as well as take appropriate actions with regional natural gas operating entities to the extent commercially and legally possible, and
3. Develop, implement and adopt, as appropriate, standards and procedures to be employed in the coordination of operations between the electric and natural gas industries to ensure the reliability of both the bulk electric and regional natural gas systems.

c. Upcoming Activities Including Timeline & Deliverables

The working committee will meet periodically to further the activities contemplated under the MOU.

5) NYISO and ISO-NE ICA – December 10, 2004

a. Structure of Operating Agreements, Protocols and MOUs

The NYISO and ISO-NE Interregional Coordination and Seams Issue Resolution Agreement is a bilateral agreement between NYISO and ISO-NE. It identifies specific seams issues that must resolved and tracks them. The agreement provides for a formal process that includes quarterly reporting to the Federal Energy Regulatory Commission.

b. Current State of Activities – NYISO and ISO-NE ICA

The agreement monitors planning activities under the Northeastern Coordinated System Plan (NCSP). To date no planning issues have been discovered that require action under the ICA rather than the NCSP.

c. Upcoming Activities Including Timeline and Deliverables – NYISO and ISO-NE ICA

The ICA will continue to monitor progress under the NCSP.

6) Northeast Independent Market Operators (NIMOCC) – 2002

a. Structure of Operating Agreements, Protocols and MOUs

The current members of the NIMOCC are NYISO, ISO-NE, and IESO. The three members meet quarterly to discuss problems and outstanding issues. Progress on outstanding issues is reported to the Boards of Directors of each organization annually.

b. Current State of Activities – NIMOCC

The agreement monitors planning activities under the Northeastern Coordinated System Plan (NCSP). To date no planning issues have been discovered that require action under NIMOCC rather than the NCSP.

c. Upcoming Activities Including Timeline and Deliverables – NIMOCC

NIMOCC will continue to monitor progress under the NCSP.

7) <u>CFE/ERCOT Interconnection Study – December 19, 2003</u>

a. Structure of Operating Agreements, Protocols and MOUs

In December 2003, The Comisión Federal de Electricidad (CFE) and ERCOT issued a report entitled, "CFE/ERCOT Interconnection Study". The study is a result of a long history of emergency assistance across the Mexico/United States border, and constitutes the first phase of a two-phase study to determine the opportunities for electric system interconnections between Northeast Mexico and Texas in both the short- and long-term. Details of both Phase I and Phase II include:

> Phase I of the study investigated the immediate consideration of support to the ERCOT transmission system along the Texas border where older inefficient generation is no longer economical to operate. In addition, synchronous ties may allow new block load support in remote areas where lengthy transmission additions would be required. Phase I alternatives leverage the existing interconnections and infrastructure and do not require lengthy regulatory review. The Phase I study identified that opportunities exist at the Matamoros/Brownsville, Reynosa/McAllen, Nuevo Laredo/Laredo, and Acuna/Del Rio areas to provide support between the electrical grids. Additional short-term recommendations included:
>
> 1. ERCOT to complete economic evaluations of alternatives to Reliability Must Run (RMR) services in south Texas;
> 2. CFE and ERCOT to develop system support services agreement;
> 3. Ensure ERCOT protocols support and facilitate transactions over CFE/ERCOT interconnections;
> 4. Transmission Service Providers (TSPs) to complete transmission upgrades to support and build the CFE/ERCOT interconnections; and
> 5. Proceed with the applicable presidential permits for the CFE/ERCOT interconnections.
>
> Phase II will evaluate long-term opportunities for interconnections that can support additional economic transactions and emergency assistance between CFE and ERCOT. Phase II studies will not be constrained by infrastructure limitation, and they are likely to involve new transmission improvements providing higher transfer capabilities.

b. Current State of Activities

All Phase I recommendations are currently being implemented. Phase II of the study is currently under way.

c. Upcoming Activities Including Timeline and Deliverables

The Phase II study will provide insights into the long-term market impacts and societal benefits from interconnection improvements including quantifying the benefits and costs to industrial, commercial, and residential customers on both sides of the border. This study will include a subjective analysis of externalities and other non-quantifiable impacts, since not all costs and benefits can be expressed in dollars or pesos. The distribution of costs and benefits will also be evaluated, to ensure that they are proportionally allocated to the different sectors of the Mexican and Texas electricity markets.

The Phase II study will also include evaluations of the impacts of interconnection investment on the following aspects of the Mexican and Texas energy markets:

1. Bilateral purchases and sales;
2. Spot market purchases and sales;
3. Emergency assistance;
4. Opportunities for reserve sharing;
5. Solid and petroleum fuels availability;
6. Natural gas availability; and
7. Delivery of energy from renewable technologies to load centers.

Because of the policy implications and economic impacts of larger bulk transmission interconnections on the CFE and ERCOT power systems, involvement by the Public Utilities Commission of Texas (PUCT) and the Secretaria de Energia (SENER) in the development and review of the Phase II study is recommended.

Phase II is expected to be completed by fall 2006.

8) Midwest ISO and SPP JOA – December 2, 2004

a. Structure of Operating Agreements, Protocols and MOUs

JOA Structure

On December 2, 2004, SPP and the Midwest ISO filed a Joint Operating Agreement ("JOA). The JOA governs aspects of the relationships between the Midwest ISO and SPP that affect reliability. The JOA resolves seams issues, providing measures to enhance data exchange and other communications, flowgate coordination, coordination of long-term transmission planning, and emergency procedures between the two RTOs.

Structured in three phases (Phases 1, Phase 2 and Phase 3), Phase 1 of the JOA became effective upon execution of the Agreement itself and included immediate implementation of a number of provisions to enhance interregional reliability. Many of those provisions were already underway in some manner and forum. From a planning perspective, Phase 1 has included formal implementation of information and data exchange (per Article IV) and coordinated regional transmission expansion planning (per Article IX).

Phase 2 continues the planning aspects of Phase 1. From a markets and operations perspective, Phase 2 is the period during which the Midwest ISO market-driven operations will interface with the non-market operation of SPP and will end when all SPP and Midwest ISO control areas on the parties' adjacent boundaries are included in LMP-based markets, at which time the Phase 3 market-to-market phase will take effect and continue in effect throughout the entire term of the JOA.

Committee Structure and Governance

Under Article IX of the JOA, the parties have established a Joint Planning Committee ("JPC") to coordinate system planning activities. Coordinated system planning includes preparation of common power system analysis models and the regular preparation of a Coordinated Systems Plan. These models permit power flow, short circuit and stability analyses for use in planning. The Coordinated Systems Plan is a final product specifying upgrades and modification necessary to efficiency and congestion management. The JPC will facilitate communications, committee work and review by appropriate governmental authorities. The parties have also agreed to the formation of an Inter-Regional Planning Stakeholder Advisory Committee ("IPSAC) to facilitate stakeholder review and input into the development of the Coordinated System Plan.

Coordinated Regional Transmission Expansion Planning

Coordinated regional transmission expansion planning across the seams will reduce congestion on an inter-RTO basis and enhance the physical and economic efficiencies of congestion management. Under the JOA, the parties have agreed to coordinate the results of their respective transmission expansion planning processes in order to establish inter-regional planning.

The JOA specifies substantial detail about the coordinated planning process. Each party shall provide the other annually with twelve categories of detailed information. Each party continues to engage in its customary internal system planning activities as required under its respective tariff and other applicable standards, and shall prepare a planning report that documents the procedures and methodologies applicable to its plan. The coordinated process will include studies for generator and merchant transmission interconnection and long-term firm transmission reservations, and provide for the recovery of study costs. The process will culminate with the preparation of a Coordinated Systems Plan applicable to both the Midwest ISO and SPP systems. This plan will integrate the parties' respective transmission expansion plans, resolve impacts across seams and address results of the underlying analyses. The detailed procedures for development and completion of the Coordinated Systems Plan assure its regular completion and updating and that stakeholders will have an appropriately high level of involvement.

Upgrade Cost Allocation

The JOA allocates two categories of upgrade costs: (a) costs within one party's borders due to generation and merchant transmission interconnection or long-term firm transmission reservations across the seams; and (b) network upgrades addressed in the Coordinated System Plan to resolve thermal or other constraints related to reliability or economic criteria (and not resulting directly from specific interconnections or reservations). Costs of upgrades under (a) will be coordinated and allocated consistent with the parties' Order 2003 compliance filings and the Commission's orders on those respective filings.

Costs of upgrades under (b) will be allocated equitably to the parties based on the nature of the constraint being resolved. The JRPC will develop procedures and standards to evaluate the parties' relative contributions to the constraint for this determination, all to be reviewed by the IPSAC. Each party will enforce the obligations to construct and own or finance transmission facilities under applicable transmission owners agreements.

9) IESO Operating and Interconnection Agreements

a. Structure of Operating Agreements, Protocols and MOUs

IESO have Operating Agreements (OA) with Ontario transmitters, and Interconnection Agreements (IA) with entities interconnected to the IESO-controlled grid (ICG).

OA Structure

Operating Agreements are in-place with 5 OEB-licensed Ontario transmitters. These Operating Agreements:

1. Establish roles and responsibilities,
2. Define facilities included within the ICG
3. Establish procedures for directing and operating the ICG,
4. Require adherence to defined operating and reliability standards,
5. Establish requirements for confidentiality, dispute resolution, indemnification, amendment and termination,
6. Establish an Administrative Committee responsible for planning and coordinating all actions under the agreement.

IA Structure

Interconnection Agreements are in-place with all neighboring Reliability Coordinators (MISO, NYISO, HQ-TE), and all neighboring transmitters in Manitoba, Minnesota, Michigan, New York and Quebec. The Interconnection Agreements:

1. Enable coordination between IESO and each of their counterparts,
2. Significant components include:
    - exchange of real-time and studies information,
    - concept of providing emergency assistance,
    - coordination of system security and equipment outages,
    - creation of the Interconnection Committee responsible for planning and coordination of all actions under the agreement, and for development and maintenance of joint operating instructions.

b. Current State of Activities

Under the Operating Agreements, the IESO and Ontario transmitters:

1. Exchange information and relevant study results related to transmission facilities,
2. Monitor existing, and foresee emerging, operational issues and develop common plans/actions to mitigate them,

Under the Interconnection Agreements, the IESO and interconnected entities:

1. Develop joint operating instructions for operation of interconnection facilities, outage coordination and information exchange, voltage/reactive control, emergency assistance, etc.,
2. Exchange information and relevant study results related to interconnected operation,
3. Coordinate interconnection transfer limit studies and emergency/restoration assistance plans (through Transmission System Study Working Groups),
4. Examine and mitigate market seams issues (through seams issue committees).

c. Upcoming Activities Including Timelines and Deliverables

The IESO, along with Ontario transmitters and neighboring entities, will continue to monitor existing, and foresee, system reliability and market issues, and work on mutually developing mitigation plans/actions.

10) CAISO Boundary Planning Activities

a. Structure of Operating Agreements, Protocols and MOUs

On November 1, 2002, the CAISO took on the leadership role in an initiative to develop a Southwest Transmission Expansion Plan (STEP). The purpose of STEP is:

> "*To provide a forum where all interested parties are encouraged to participate in the planning, coordination, and implementation of a robust transmission system between the Arizona, Nevada, Mexico, and southern California areas that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. The wide participation envisioned in this process is intended to result in a plan that meets a variety of needs and has a broad basis of support.*"

On June 30, 2003, the CAISO communicated its interest, to entities located in the Northwest portion of the WECC, in forming a sub-regional planning effort between California and the Northwest. Subsequently, the Northwest Transmission Assessment Committee (NTAC) was formed, in which the CAISO participates.

On December 5, 2002, the Seams Steering Group-Western Interconnection (SSG-WI) was formed among three potential Regional Transmission Operators in the West, RTO West (in the Northwest), WestConnect (in the Southwest), and the California Independent System Operator (California ISO). The three entities are working together to facilitate a regional market for electricity that makes the best use of generating and transmission resources. That effort is focused on resolving commercial, operational and policy issues that arise with the creation of three RTOs in the West. For a variety of reasons, some of the initially envisioned SSG-WI activities may be transferred to the WECC.

b. Current State of Activities

Transmission expansion projects to increase the transfer capability between Arizona and California by 505 MW have been developed by STEP and are currently under construction. Additional projects to increase this path another 1200 MW are in the permitting process.

Transmission expansion projects to increase the transfer capability between the Northwest and California are in the early planning process.

Transmission projects to connect potential coal-fired and wind generation and create 3000 MW of transfer capability between Wyoming, Colorado, Idaho, Montana, Utah, Nevada, and California are in the early planning process.