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ISO/RTO Council

Increasing Renewable Resources

How ISOs and RTOs Are Helping Meet This Public Policy Objective

ISO/RTO Council

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Table of Contents

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List of Figures

List of Tables

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Executive Summary

Elected officials and other policymakers have long recognized the benefits provided by renewable resources.[1] Renewable resources provide electric energy with little or no emissions, reduce dependence on fossil fuels, and strengthen local economies. Renewable resources, including hydroelectric generation, currently supply about 9% of the electric energy provided by North America's Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).[2] To encourage renewable resources, policymakers have implemented favorable tax policies at the federal and state levels, and 25 states (and the District of Columbia) have implemented Renewable Portfolio Standards that require utilities to supply a targeted percentage of their electric energy from renewable resources. The combination of Renewable Portfolio Standards (RPSs) and tax policies have helped make renewable energy financially viable in many areas.

To meet the policy objectives of increasing renewable resources, developers must be able to build these projects and bring them to market. The markets supported by the ISOs and RTOs have proven to be fertile ground for the development of renewable resources. Figure ES–1 shows significant potential growth in renewable resources in ISOs and RTOs. Four ISO and RTO areas are planning sufficient resources to meet Renewable Portfolio Standards, while the states comprising the three other ISOs and RTOs are making significant progress toward meeting those standards.

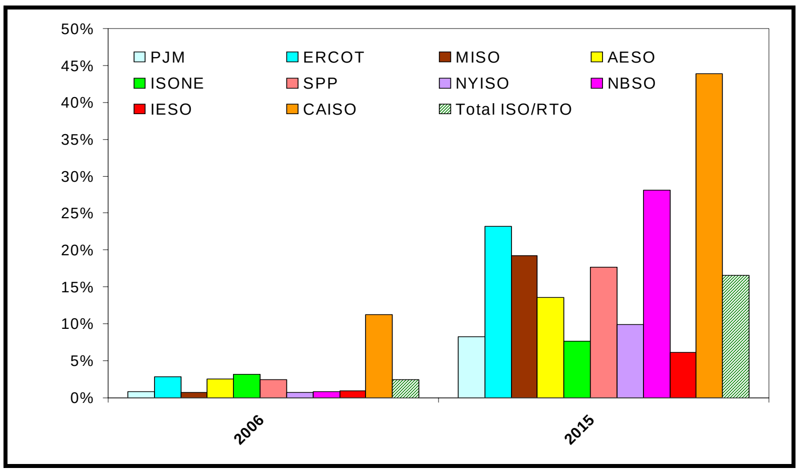

Figure ES–1: Current ISO and RTO non-hydro renewable energy resources and proposed renewable energy projects in ISO and RTO interconnection queues.

Note: These data are from the ISO and RTO generation interconnection queues. Not all proposed projects in these queues will be developed, but no other consistent source of planned project information exists. Therefore, the projections in this report should be viewed as estimates of maximum potential.

[1] Renewable resources can include solar, hydro, wind, selected biomass, geothermal, ocean thermal, tidal sources of power, and landfill gas. Some states consider fuel cells to be a renewable resource, and some do not count pumped hydro, since the electricity for pumping comes mostly from fossil fuel generators. Appendix A includes more details on various state renewable energy policies.

[2] ISOs and RTOs are the organizations that operate the power grid and the electricity markets for two-thirds of the electricity demand in the U.S. and just over 40% in Canada. As of 2007, the North American ISOs and RTOs include the Alberta Electric System Operator (AESO), California Independent System Operator Corporation (CAISO), Electric Reliability Council of Texas (ERCOT), Ontario's Independent Electricity System Operator (IESO), ISO New England, Inc. (ISO-NE), Midwest Independent Transmission System Operator, Inc. (MISO), New York Independent System Operator (NYISO), New Brunswick System Operator (NBSO), PJM Interconnection, L.L.C. (PJM), and Southwest Power Pool (SPP).

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The success of markets in enabling renewable resources is evidenced by the fact that ISOs and RTOs host 79% of today's installed wind generation, which is well above their 44% share of wind energy potential and 53% share of total North American electricity demand.[3]

Renewable generators account for 142,171 megawatts (MW) of the 326,459 MW of generation in the ISO and RTO interconnection queues. Figure ES-2 shows that wind generation is the largest proposed generation technology in the ISO and RTO queues, totaling 124,012 MW. This exceeds natural gas (89,579 MW), is more than double that of coal (55,667 MW), and is nearly four times that of nuclear (36,047 MW). Wind accounts for 87% of the renewable generation in the ISO and RTO queues. California is the only ISO or RTO area with a significant amount of proposed solar generation.

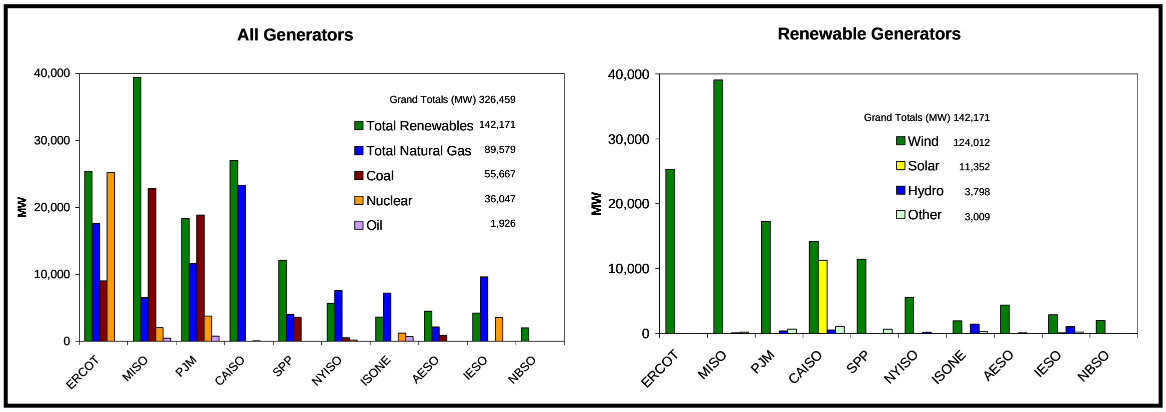

Figure ES–2: Renewable generation is the largest type of proposed generation in most regions. Wind generation accounts for most of the proposed renewable generation.

The coordinated regional planning of ISOs and RTOs also helps facilitate the growth of renewable energy generation. ISOs and RTOs are finding innovative ways to finance and build transmission lines to solve the problem of bringing renewable generation in remote sites to market. The Federal Energy Regulatory Commission (FERC) has preliminarily approved a CAISO proposal to develop transmission to service regions with significant but location-constrained renewable generation potential. Costs will be allocated to all transmission customers until the renewable generation is built, at which point generation owners will bear proportionate shares of the costs. Texas has initiated a process to designate Competitive Renewable Energy Zones (CREZs) and build transmission to serve selected CREZs to facilitate the proposed development of thousands of megawatts of new wind generation. Initial CREZ designations are expected later this year.

The large wholesale electricity markets operated by ISOs and RTOs help minimize the cost of electricity to consumers by taking advantage of economies of scale in generation and transmission; more efficient use of the energy provided by existing electric generators; and reducing the need for generating capacity overall. Four features of these wholesale electricity markets play an especially critical role in developing renewable resources. First, large, organized markets in ISO and RTO regions are open to all those interested in investing and building new power plants. Second, the price transparency of these markets lets developers know the value of their power, making investment decisions easier. Third, the five- to fifteen-minute dispatch of these large markets and the large size of these markets reduce the cost of integrating wind into the power system by taking advantage of wind diversity and the ramping capability of conventional generators. Fourth, coordination of regional transmission planning makes it possible to build the transmission needed to bring renewable energy to market. These features are enhanced by the open

[3] Michael Skelly. February 27, 2007. Comments, Federal Energy Regulatory Commission (FERC) Docket No. AD07-7-000.

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governance process of ISOs and RTOs, which includes extensive stakeholder input in establishing market rules and can quickly respond to the needs of new technologies.

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Introduction

ISOs and RTOs facilitate the integration of renewable generation into the bulk electric power system. ISOs and RTOs typically feature large electricity markets that often span multiple states and provinces. These organized, wholesale electricity markets provide ready access for generation developers. They also provide beneficial competition and economies of scale for customers, thus reducing the regional need for capacity, for example. All these activities are in the context of an open governance process that provides a responsive means of improving the market design to accommodate new technologies. Wholesale electricity markets also greatly reduce the cost of integrating wind and other renewables into the power system by accommodating the within-hour variation of renewable resources. Bilateral markets in the rest of the country generally are conducted hourly and include penalties for failing to deliver or for over delivering in a given hour.

Wind, solar, geothermal, small hydro, and biomass are all being deployed on the North American bulk electric power grid. Renewable generation currently provides about 8.6% of the ISOs' and RTOs' electric energy, of which 6.2% is supplied by large hydro, 1.2% by wind, and the remaining 1.3% by geothermal, biomass, and solar.[4] The amounts are increasing. In California, for example, the Intermittency Analysis Project, funded by the California Energy Commission, estimated the potential for large amounts of wind and solar in California. That study assumed that wind and solar would supply 7,500 MW and 1,900 MW, respectively, by 2010. By 2010, wind and solar would supply 12,700 MW and 6,000 MW, respectively, if the state increases its RPS goal from 20% to 33%.

This paper addresses all renewables but focuses on wind generation for two reasons. First, wind generation is by far the largest single type of renewable resource currently and is showing extraordinary growth. Second, wind variability makes it the most difficult to integrate into the power system. Other renewable generation types, such as biomass and geothermal, for example, are similar to conventional generation. The solar category includes photovoltaic, concentrating troughs, concentrating towers, and sterling engine powered plants.

Wind primarily is an energy resource. Its main value is in saving fuel and reducing emissions, and it provides environmental, reliability, and economic benefits. However, it is not primarily a capacity resource. Measuring wind plants on the basis of their energy output in megawatt-hours (MWh or MWh/year) and referring to a 1.5 MW wind turbine as a 4,400 MWh/year turbine, would be more precise, for example. Unfortunately, the 4,400 MWh/year terminology is not well understood. Therefore, this paper continues the convention of referring to wind generators and plants by the nameplate ratings but seeks to emphasize that these are not the capacity values of the plants nor will they support that many megawatts of peak load. Typical wind capacity factors range from about 20% per year to about 40% per year, depending on the project.

[4] Refer to Appendix A for more details on how the states within the ISOs and RTOs classify renewable resources.

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The Renewable Resources Imperative

Renewables enjoy support from many quarters: energy experts, environmentalists, policymakers, and the general public, and there is strong interest in increasing renewable-based generation throughout the country. This interest and support is being manifested through the development of physical resources supplying customer loads. In 2006, wind was the second-largest source of new generation, exceeded only by natural gas-fired generation. This chapter briefly discusses some of the features of renewable generation that regulators and the public find attractive. It also describes the generation queue for new generation and the state Renewable Portfolio Standards.

Renewable Generation Benefits

Renewable resources offer a range of environmental, economic, and societal benefits that underlie the public policy support for renewable generation in the form of Renewable Portfolio Standards and favorable tax treatment.

Emissions Reductions

Renewable generators produce no emissions and improve the environment by reducing the need to operate fossil-fuel-burning generators.[5] By displacing the use of fossil fuels, renewables reduce sulfur dioxide (SO_2), nitrogen oxides (NO_X), ozone, and particulate emissions and thus help to clean the air. They do not emit mercury, create ash, or generate sludge, which must be disposed of. Most do not consume any water to generate electricity.[6] Perhaps most importantly, they do not generate carbon dioxide (CO_2) or other greenhouse gases that contribute to global warming.

The quantities of fuels displaced by wind in a given regional market are a function of the mix of other generation resources, the time of day the wind typically blows, and the amount of wind power added.

Table 1 quantifies some of the annual environmental savings that a typical wind generator in Texas provides. According to a recent ERCOT report on CREZs, wind typically displaced gas-fired generation 80% of the time and coal-fired generation 20% of the time. Regional markets that have generation mixes and marginal fuel types similar to ERCOT's would show comparable results. Results also would be similar for other types of renewables and would rise with an increase in the capacity factor.

[5] Generators that burn biomass, which is treated as a renewable resource under certain state RPS plans, do produce emissions.

[6] Some states' renewable energy policies restrict the eligibility of hydroelectric generation.

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Table 1
Emissions Reductions and Water Savings from Wind Generation

Emission	Annual Reduction per MW Wind
CO_2[(a)]	2,050 ton/yr
SO_X[(a)]	1.4 ton/yr
NO_X[(a)]	0.7 ton/yr
Mercury[(b)]	0.2 lb/yr
Water savings[(c)]	1.4 million gallons

(a) Based on 5,000 MW of wind, where wind displaces 80% gas and 20% coal. "Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas," (ERCOT 2006A).

(b) Department of Energy and Energy Information Administration

(b) Based on a 35% wind capacity factor. P. Torcellini, N. Long, and R. Judkoff, "Consumptive Water Use for U.S. Power Production," (National Renewables Energy Laboratory, 2003).

Economic and Security Benefits

Renewables provide security benefits in several ways. Increased fuel diversity improves power system reliability and reduces consumption of foreign-sourced fuels. Renewables provide economic benefits and reduce price volatility in wholesale electricity markets because they are unaffected by fuel-price swings. They provide a fuel-price hedge for the same reason. The near-zero marginal cost reduces market-clearing prices.

In large enough quantities, renewable energy generation also may impact natural gas prices by reducing the demand for natural gas. A Lawrence Berkeley National Laboratory report that surveyed other modeling studies, including those from the EIA, found that increased levels of renewable energy (such as through an RPS) and energy efficiency could reduce natural gas prices by reducing the demand for natural gas in the electric power sector. The study estimated that consumer bills would be reduced by between $7.50/MWh and $20/MWh because lower natural gas prices reduce electricity prices (Wiser, 2005).

Renewable Generation and Generation Queues

An initial step in developing any new generation project and getting permission to interconnect it to the power system involves placing the project in the generation interconnection study queue.[7] The interconnection queue determines the transmission improvements necessary to interconnect a project to the power system. Being in the generation queue does not guarantee that a project actually will be built, but it is a necessary step for all projects.

It must be emphasized that, while generation queues are indicative of planned generation, not all generation in the queues will be built. In the short run, some of the projects in the queue will fail to materialize, but in the longer run, additional projects will enter the queue and be developed. This report relies on the ISO and RTO generation queues to measure the amount of planned generation because no other consistent source of

[7] Transmission system operators use a queue to manage generator interconnection requests. Interconnection requests are studied and approved either in the order they are received (placed in the queue) or simultaneously in batches of requests that enter the queue at about the same time. Queue position can be very important to a generator in determining the availability and cost of required transmission.

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such information is available. Therefore, the projections in this report should be viewed as estimates, which likely are high. The numbers presented in this report were current as of mid-April 2007.

Table 2 shows current renewable generation (which can include small hydro, large hydro, or a combination of both) in each of the ISOs and RTOs as a percentage of delivered electric energy. As shown, several ISOs already obtain a large portion of their electric energy from nonemitting, renewable resources. In total, as of 2006, the ISOs and RTOs obtain a substantial 9% of their energy from these renewables.

Table 2
Percent of ISO and RTO Electric Energy Generation
Provided by Renewables, Including Hydro

ISO/RTO	2006 Actual
AESO	5%
CAISO	32%
ERCOT	3%
IESO	24%
ISO-NE	5%
MISO	4%
NBSO	20%
NYISO	16%
PJM	3%
SPP	7%
Total ISO/RTO	9%

Figure 1 shows the total nameplate capacity of the various types of generation in each of the ISO and RTO queues. Developers are proposing to build over 300,000 MW of new generation, nearly one-third the size of the entire existing generation fleet based on installed capacity. Renewables exceed all other generation types in nameplate rating and represent 44% of the total. Figure 1 further differentiates among the various renewable generation technologies. The 124,012 MW of wind generation being proposed in the ISOs and RTOs is more than a twelve-fold increase in the amount of installed wind generation. The growth of wind generation can be attributed to several factors, including favorable tax treatment, the implementation of RPS standards, and the maturation of wind generation technology. Among renewables, wind is by far the largest single type of resources for the foreseeable future (see Figure 2). Though not nearly as large as wind or solar, the proposed additions for hydro, geothermal, and biomass are impressive on their own, totaling 6,807 MW.

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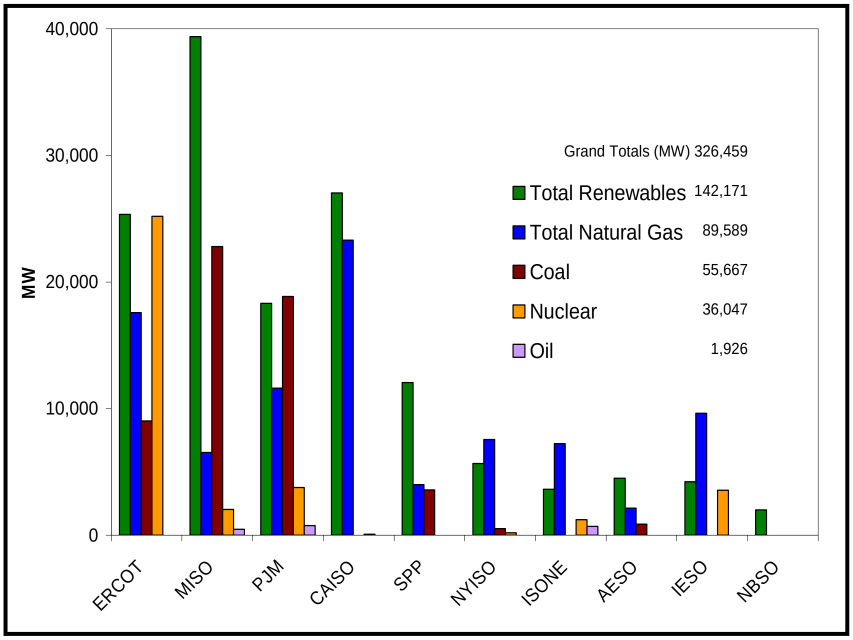

Figure 1: Generator queue nameplate ratings indicate the interest in different fuel types in each of the RTOs and ISOs.

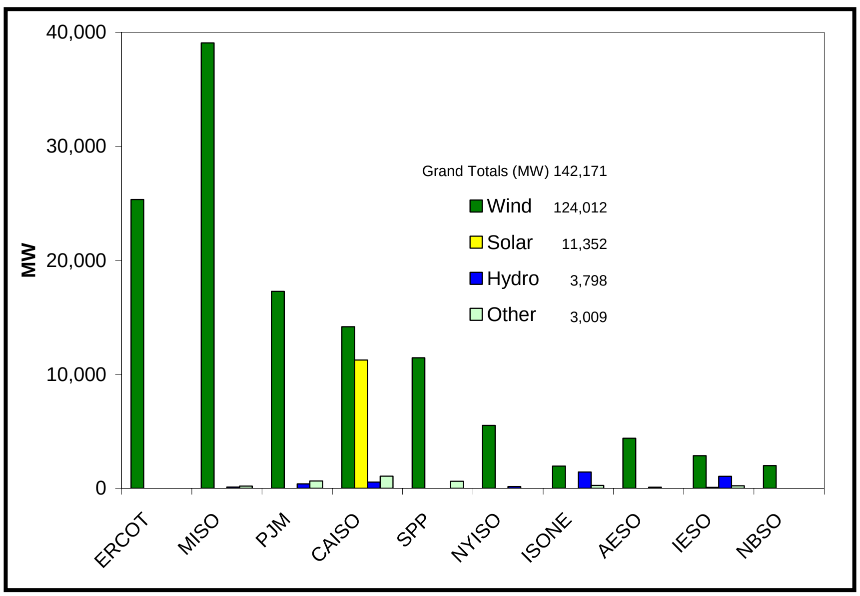

Figure 2: Wind is the largest single type of proposed renewable generation, with solar making a strong showing in California.

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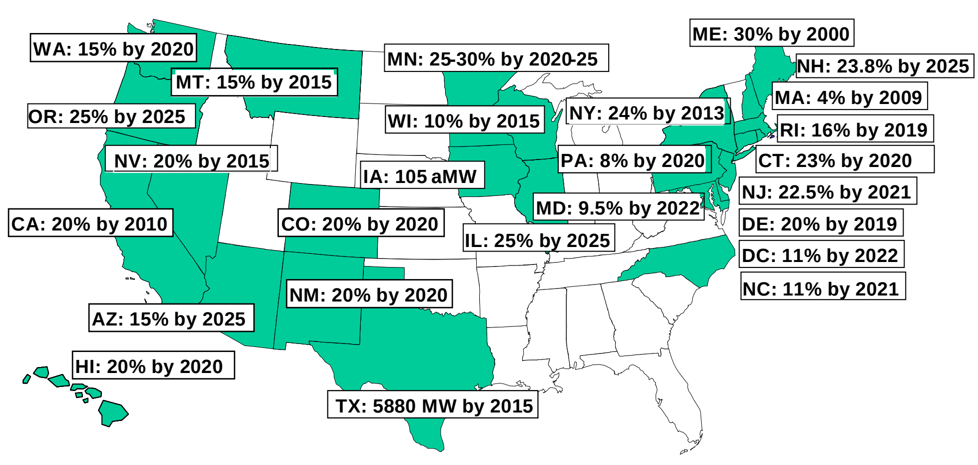
ISOs and RTOs Support the Implementation and Administration of Renewable Portfolio Standards

In general, Renewable Portfolio Standards require load-serving entities to meet a specified percentage of their annual retail sales of electricity with energy from eligible technologies that generally (but not always) are limited to renewable energy resources. Typically, the standard increases over time, and a penalty may be levied if the standard is not met. In nearly all cases, the Renewable Portfolio Standard is measured as a percentage of total electric energy consumed rather than a percentage of required capacity. In many states, Renewable Portfolio Standard compliance is affected through renewable energy credits (RECs), with one REC representing 1 MWh of renewable energy generation. Typically, RECs can be sold or traded among market participants until they are used for RPS compliance.

To date, 25 states and the District of Columbia have enacted Renewable Portfolio Standards (see Figure 3), and all of them differ in several key aspects, such as resource eligibility, size of target, treatment of existing renewables compared with new renewables, whether RECs are used or not, the consequences of noncompliance, and other program details, such as banking of RECs, multipliers for certain resources, and the availability of compliance waivers. About 40% of load nationwide is covered by a Renewable Portfolio Standard. Of the 25 states and the District of Columbia with such policies, 17 are served at least partially by an ISO or RTO. ISO/RTO Renewable Portfolio Standards requirements and the year in which they apply are shown in Figure 3. Besides mandatory requirements, voluntary renewable energy targets are in place in Vermont, North Dakota, Virginia, and Missouri. Since utilities are not required to meet these guidelines, they are not included further in this analysis. (Wiser, 2007)



Additional renewable energy “goals” established in IA, VT, VA, MO, ND and ME

Figure 3: State Renewable Portfolio Standards Policies for 25 States and D.C.

Source: Union of Concerned Scientists

Table 3 shows the percentage of electric energy supplied by non-hydro renewable resources in 2006 in ISO and RTO regions and the RPS requirements for 2015. Table 3 excludes large hydro units to permit comparison with RPS requirements and indicates the percentage of electric energy that new renewable resources will need to supply by 2015.

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Table 3
Current Renewable Energy Resources and Future RPS Requirements

ISO/RTO	2006	2015
	% Electric Energy From Non-Hydro Renewables	RPS Requirements
AESO	3%	N/A
CAISO	11%	20%
ERCOT	3%	5%[(a)]
IESO	1%	N/A[(b)]
ISO-NE[(c)]	3%	11.7%
MISO	1%	3.8%[(d)]
NBSO	1%	10%
NYISO	1%	25%[(e)]
PJM	1%	11.8%[(f)]
SPP	2%	N/A
Total ISO/RTO	2%	N/A

(a) Texas' Renewable Portfolio Standards call for 5,880 MW of renewables by 2015, which is equivalent to roughly 5% of demand.

(b) Ontario's long-term supply plan shows 6% energy from renewables (excluding large hydroelectric) by 2015.

(c) For 2006, total renewable resources provide almost 12% of New England's electric energy. However, this amount includes large hydro resources, which are not counted toward RPS requirements. For 2015, 11.7% represents the weighted average of Renewable Portfolio Standards policies in Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island.

(d) This percentage represents the weighted average of Renewable Portfolio Standards policies in Iowa, Minnesota, and Wisconsin.

(e) New York's RPS calls for an increase in renewables from a 2004 base level of 19% (18% of which is large hydropower) to 25% by the year 2013. Centralized procurement aims to provide about 24% and a voluntary green market would provide at least the other 1%.

(f) This percentage represents the weighted average of Renewable Portfolio Standards policies in the District of Columbia, Delaware, Maryland, New Jersey, and Pennsylvania.

ISOs and RTOs play an important role in the implementation of Renewable Portfolio Standards. Most prominently, they help with tracking generation, RECS, or both because ISOs and RTOs have the generation and load data necessary to measure Renewable Portfolio Standards compliance. PJM and ERCOT administer tracking systems for RPS implementation and compliance.[8] ISO-NE provides all the operational data needed to run New England's Generation Information System, and New York is in the process of designing and implementing a tracking system. MISO provides the data for the Midwest Renewable Energy Tracking System (M-RETS).

[8] PJM Environmental Information Systems, a subsidiary of PJM, administers the Generator Attribute Tracking System for PJM.

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Appendix A contains a description of state Renewable Portfolio Standards policies for each ISO and RTO; the activities of each ISO and RTOs in relation to the Renewable Portfolio Standards and renewables; and the outlook for renewable energy in each ISO and RTO.

Table 4 shows that the combination of policy initiatives and open wholesale electricity markets are creating a favorable environment for meeting renewable energy goals. Although not all the renewable energy projects proposed in the various ISO and RTO interconnection queues likely will be built, the size of the queue in each region indicates the market interest in investing in renewable resources.

Table 4
Non-Hydro Renewable Energy Projects
Proposed in ISO and RTO Interconnection Queues

ISO/RTO	2015 Potential % of Energy from Renewables
AESO	15%
CAISO	44%
ERCOT	23%
IESO	6%
ISO-NE	8%
MISO	19%
NBSO	28%
NYISO	10%
PJM	8%
SPP	18%

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ISOs and RTOs Help Meet the Policy Objective of Increased Renewable Resources

Policymakers have implemented favorable tax treatment and Renewable Portfolio Standards to encourage the development of renewable resources. These financial incentives motivate the development of renewable resources. However, developers must still get renewable projects built. ISOs and RTOs have proven to be successful in facilitating the construction of renewable resources for a number of reasons as are described below.

The large wholesale electricity markets operated by ISOs and RTOs provide less expensive electricity to consumers by taking advantage of economies of scale in generation and transmission, more efficient use of the energy provided by existing electric generators, and a reduced need for generating capacity overall.[9] Four features of these large wholesale electricity markets play an especially critical role in the development of renewable resources. First, ISO and RTO markets are open to all parties interested in investing and building new power plants. Second, the price transparency of these markets informs developers about the value of their power, making investment decisions easier. Third, the five- to fifteen-minute dispatch of these large markets reduces the integration costs of wind, and the large size of these markets further reduces integration costs by taking advantage of wind diversity and the ramping capability of conventional generators. Fourth, regional transmission planning makes it possible to build the transmission needed to bring renewable energy to market. These features are enhanced by the ISOs' and RTOs' open governance processes, which include extensive stakeholder input in establishing market rules and can quickly respond to the needs of new technologies.

The ability to use conventional generation to support wind generation is economically efficient because it maximizes the amount of zero-marginal-cost energy that wind can provide and helps lower energy prices to customers. (Milligan, Kirby, 2007; Kirby, Milligan, Wan 2006; Kirby, Milligan 2005)

Price Transparency

ISO and RTO wholesale markets provide price transparency to inform all market participants, including renewable generation owners, about the price and the value of their power. Without transparent markets, the dispatch price is not public, and valuing generation investments is much more difficult. For example, if a project is not in an ISO or RTO region, the project developer will have to negotiate with a utility to sell the power bilaterally, and the price that the utility is willing to pay is based on information that is not likely available to the developer. In wholesale electricity markets, developers have access to both historical data and forward price curves to estimate the future value of their generation. This price transparency makes it easier to determine whether projects are feasible (considering tax benefits and participation in any applicable Renewable Portfolio Standard as well) early in the development cycle.

Open Access

Membership and participation in ISO and RTO markets is open to all interested parties. This encourages the development of new resources by expanding the number of potential developers. In these markets, the process for developing new resources and interconnecting them to the bulk power system is open and transparent. The ability to interconnect and sell output is also easier in ISOs and RTOs. It is easier to

[9] Most of the ISOs/RTOs currently have a real-time energy balancing market; many have day-ahead energy markets, other ancillary services, and capacity markets as well.

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develop a project in this environment than in utility service areas that have a single host utility, which often is the only buyer for a project.

The open access feature of ISO and RTO markets means that a large number of participants exist in those markets. The price transparency in these markets makes it possible for all participants to value future generation. The combination of these two features make it easier for wind and solar developers to either sell into robust spot markets or to find a bilateral contracting partner and thereby obtain the contracts that will make project financing possible.

Large, Flexible Markets with Five- to Fifteen-Minute Dispatch

Areas without ISOs and RTOs typically allow hourly schedules only. This means that most generators are forced to follow flat hourly schedules set one hour or more in advance. In these regions, changes in load or generation output within the hour are met by units on regulation service. Regulation units receive signals every few seconds to change their output to balance load and generation. This is a much more expensive way to achieve generation and load balance than by sending economic dispatch signals to all of the generators every five to fifteen minutes. The benefits of the ISO and RTO market structure can be seen in the following analysis that shows significantly lower operating costs in ISO and RTO regions for integrating wind into the power system.

In the past few years, several wind-integration studies have been conducted in the United States. These analyses focus on the physical requirements of wind integration and calculate the wind-integration cost under the assumption that integrating wind generation will not be allowed to degrade reliability. Calculated integration costs have tended to drop as a result of more sophisticated analysis techniques and greater understanding about the interactions between the power system and large amounts of wind generation.[10]

To calculate expected wind-integration costs, wind-integration studies model the power system with and without wind generation. Total system costs are compared with and without wind. The cost of integrating wind is the operating cost difference between the with-wind and without-wind cases. Modelers have to be careful to account for the wind energy value separately from the wind-integration cost. Clearly, system operating costs will be lower when a large amount of zero-operating-cost energy is added to the power system, but that is not the cost difference wind-integration studies are designed to determine. Wind-integration studies are designed to determine the costs of integrating wind, not the value of the wind energy itself.

Wind-integration studies quantify several types of increased costs:

- Regulation—wind variability increases the minute-to-minute variability of the entire power system, resulting in the need for additional generation providing regulation on automatic generation control (AGC).[11] Though regulation is the most expensive ancillary service, the increased cost caused by adding wind generation typically is very modest.

[10] Large amounts of wind generation do not significantly increase the cost of regulation or automatic generation control. Intra-hour and inter-hour swings are a larger cost concern. Mesoscale wind modeling—which can provide multiple years of 10-minute or faster wind power data at multiple sites that are time synchronized to historical power system load data—has been a major analysis advance.

[11] To maintain system reliability, power systems balance load and generation on a moment to-moment basis using automatic generation control.

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- Load following—wind variability also increases the intra-hour and inter-hour variability of the entire power system resulting in the need for conventional generators that are supplying energy to adjust output every 10 to 30 minutes. This cost is modest in ISO and RTO regions that operate five- to fifteen-minute energy markets. Costs are higher in areas that have only hourly energy markets or hourly-adjustable bilateral contracts.
- Unit commitment—day-ahead wind forecast errors can result in too much or too little conventional generation being scheduled for the next day's operation. Forecast errors also can result in the incorrect amount of natural gas fuel being scheduled for conventional generator use. System operating costs increase when conventional generators operate inefficiently because too many are on line. System operating costs also increase when too few low-cost conventional generators are scheduled to operate and high-cost quick-start generators must be used instead. These costs are lower in larger regions with larger generation pools. They also are lower in regions with more flexible generators.

Wind-integration models typically use three or more years of minute-to-minute power system data (actual loads, conventional generator availability, hydro generation water conditions, etc.) coupled with 10-minute or faster wind speed data for the same period. Recent advances in mesoscale atmospheric modeling make it possible to determine minute-to-minute wind speeds at windmill tower hub heights and at proposed wind plant locations throughout a region based on the vast amount of data constantly being collected by ground stations, satellites, weather balloons, and aircraft. Each wind-speed value is converted into wind power for each small group of proposed wind turbines. Operation of the power system is then modeled using the same generation commitment and dispatch tools that are used in actual operation. Power system operating costs are calculated for all generators and all hours. The coupling of minute-to-minute wind data with minute-to-minute power system data results in accurate modeling of the cost impacts that wind power has on power system operations.

Table 5 shows results from several recent wind-integration studies (Smith et. al, 2007; Northwest Wind Integration Action Plan, 2007).[12] In general, the studies show lower integration costs in ISOs and RTOs than in smaller, single-utility service areas. The integration costs for the three ISO and RTO studies range from zero to $4.41/MWh of wind, while the integration costs for the two non-ISO or RTO studies range from $8.84 to $16.16/MWh. One reason for these results is that the three ISOs and RTOs operate subhourly markets (i.e., they dispatch generation on a five- to fifteen-minute timeframe), while the two non-ISOs or RTOs require generators to follow hourly schedules and obtain all subhourly balancing from regulating units. Another reason for these results is the large size (discussed below) of ISOs and RTOs, which means much more conventional generation with ramping capability is available to respond to changes in wind output while maintaining the balance between generation and load, thereby reducing wind integration costs. (Section 3.3.1 includes additional information about the importance of subhourly markets for integrating renewables.)

[12] The quoted integration costs are actually the operating cost impacts. Some studies quantify additional wind related costs.

Table 5
Wind-Integration Cost Study Results

Date	Study	ISO/RTO	Wind Capacity Penetration	Integration Cost: $/MWh of Wind Output	Energy Market Interval
3/05	NYISO	ISO/RTO	10%	Very low	5 minute
12/06	Minnesota/MISO	ISO/RTO	31%	$4.41	5 minute
2/07	GE/Pier/CAIAP[(a)]	ISO/RTO	33%	$0–$0.69	10 minute
3/07	Avista	No	30%	$8.84	1 hour
3/07	Idaho Power[(b)]	No	30%	$7.92	1 hour

(a) Includes two-thirds wind and one-third solar and includes costs increase of regulation and load following assigned to regulation.

(b) Reduced from $16.16 in September 2007 settlement proceedings.

Because precisely scheduling intermittent renewable energy generation in advance is difficult, some ISOs and RTOs have enacted market rules to accommodate the unique characteristics of intermittent renewables. PJM, for instance, accepts wind as a price taker in the real-time market and does not require wind generators to bid into the day-ahead market. PJM imposes an operating reserve charge for differentials greater than 5 MW to recover the costs from decommitting already committed generators. On average, the operating reserve charge is generally about $2–3/MWh, although it can vary. With FERC approval, the NYISO exempts up to 1,000 MW of intermittent generation from over- and under-generation penalties and plans to propose market rules for all intermittent generation regardless of the number of intermittent generators in operation. California, New York, and New England do not require renewables to bid into day-ahead markets. Other examples are provided in Appendix A.

Subhourly Markets or Five- to Fifteen-Minute Dispatch

Utilities outside of ISO/RTOs generally require those selling into their systems, and therefore not being dispatched by the system operator, to have fixed hourly schedules that are set in advance. Dispatch signals are sent to adjust generation output hourly. Within-hour variation in output is handled by specific units on AGC that are providing minute-to-minute regulation. Because all within-hour variation is handled by a small set of generation, wear and tear and the opportunity costs are significant for these generators. This market structure was designed to facilitate sales between utilities, which were generally backed by firm or unit-contingent generation schedules, but it does not work well with variable renewable energy generators. In ISOs and RTOs, market dispatch signals are sent to generators every five to fifteen minutes to ensure that the least expensive combination of generators is being used to meet load. This means that variations in wind output can be accommodated by all generators, not just units on regulation. The combination of AGC and the five- to fifteen-minute dispatch of generators means that ISO and RTO markets and operations can accommodate the intra-hour variability of wind and solar generation and maintain system reliability. Table 4 demonstrates that the integration costs of wind are much lower in ISO and RTO markets.

Figure 4 shows how subhourly energy markets can reduce the need for regulation. The top portion of Figure 4 shows a typical balancing area total power requirement (load netted with wind). Conventional generation must match both the daily load pattern and the minute-to-minute random fluctuations. The lower half of the figure compares the residual regulation that is required from AGC units in the hourly

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market case with the five-minute dispatch case during part of the morning ramp-up (4 a.m. to 7 a.m). The lower green curve is the regulation required by the hourly-only market structure. The upper red curve shows that the five-minute market structure requires less than one-third of the regulation the hourly-only market requires for exactly the same physical power system.

Figure 4 shows why it is less costly to integrate wind into a market using five-minute dispatch rather than hourly dispatch. Five-minute dispatch results in the need for much less AGC ramping outside the economic dispatch signals, which significantly reduces the cost of regulation. Balancing areas that do not have subhourly energy markets force generators and loads to abide by fixed hourly schedules, often set up to 90 minutes before the start of the hour. Deviations from scheduled consumption or production are balanced by the AGC units. Unfortunately, AGC is the most expensive ancillary service. In some locations, this more than doubles the cost to integrate wind generation. AGC is designed to respond to the random, moment-to-moment variations of loads and generators. It is not necessary for reliability purposes, and it is needlessly expensive to use regulation to respond to subhourly movements of load and generation, including wind and other uncontrolled renewable generators.

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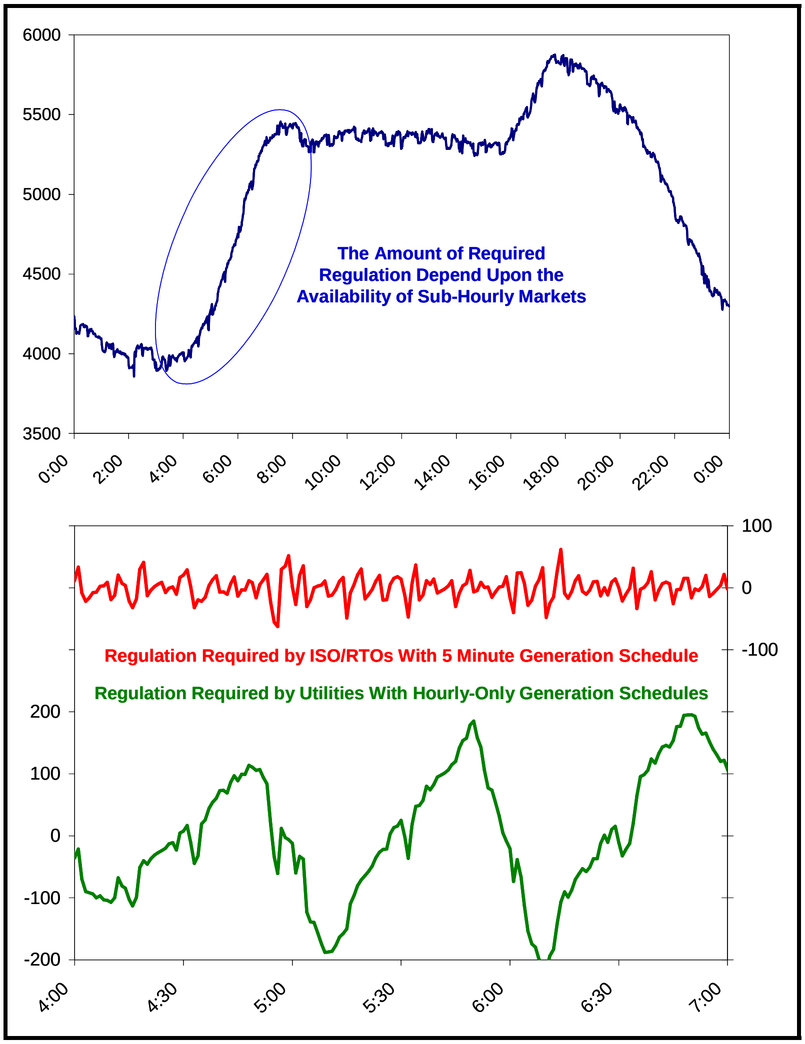

Figure 4: This balancing area would require less than one-third of the regulation it currently needs to accommodate the morning ramp if it had five-minute markets.

As a result of scheduling rules that require generators adhere to flat hourly schedules, hourly-only energy market structures do not dispatch the subhourly ramping capability that physically exists in the conventional generation fleet. In contrast, subhourly energy dispatch provides access to the maneuvering capability that is physically available from each of the generators that is actively supplying the energy market. The subhourly dispatch has the added benefit of energy prices that accurately include the impact of wind generation. (Milligan and Kirby, 2007; Kirby and Milligan, 2005; Milligan and Wan, 2006)

Large Geographic and Electrical Size

ISOs and RTOs typically are large in both physical geography and electrical load. These characteristics help reduce load volatility and the cost of balancing aggregate load with aggregate generation. This principle is not new; utilities have been taking advantage of aggregation for a century. Reserve sharing groups, for example, combine their contingency-reserve requirements and resources to reduce the cost of responding to generator outages, which takes advantage of aggregating larger groups of generators. ISOs and RTOs simply take the concept to a new level with their ability to integrate across multiple-utility boundaries.

The large area typically covered by ISOs and RTOs also means that the availability of the wind resource in an ISO or RTO will tend to be significantly diverse. The relationships among distance, time, and wind-plant variability correlation are shown in Figure 5 (Ernst, Wan, and Kirby, 1999). Each line on the chart shows the correlation between wind levels at different locations as the distance between the locations increase. The different lines on the chart represent averages over different time intervals. For example, for the five-minute curve, the maximum correlation is only 20%, and the correlation drops to less than 10% when the distance increases to only 10 km. Correlation in the hourly time frame drops to less than 20% when distances exceed about 80 km. Because of this, the ramping and load-following requirements for an ISO- or RTO-dispersed wind resource will be much smaller than if all the wind were located in the same place. Appendix B provides an example of a large ramping event in Texas that clearly shoes the benefits of geographic diversity.

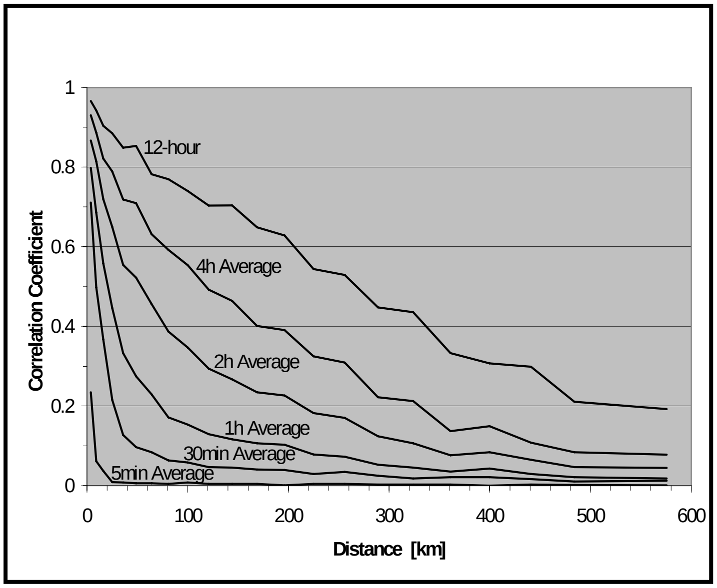

Figure 5: Wind-generator variability loses correlation as the distance between machines increases and as the timeframe of interest decreases.

The large area of ISOs and RTOs also means the per-unit cost of providing regulation service drops. This occurs because as the market size grows, regulation requirements increase at a much slower rate than its energy requirements. For example, a balancing area that is twice the size of another only requires 41% more regulating reserves, reducing the per-unit cost of providing regulation. Wind exhibits a similar behavior, and when aggregated with load, wind-regulation requirements are generally modest.

ISOs and RTOs reduce wind-integration costs by: 1) providing five- to fifteen-minute dispatch that uses the ramping capability of the conventional generation fleet, 2) taking advantage of the wind diversity over a large geographic area, and 3) aggregating large amounts of wind with large amounts of load to reduce the relative variability of both.

Open and Effective Transmission Planning

Because renewable generators are often located far from load centers, additional transmission lines will be required to interconnect the large increase in renewable generation expected over the next several years.

ISOs and RTOs areas are taking the lead in building new transmission to make up for the nearly two decades without significant new transmission and to support deliverability of renewable resources. ISO-administered regional planning processes facilitate the identification of system needs and have supported much new transmission construction in the past few years. The regional planning processes are also able to measure the benefits of renewable resources in meeting future energy needs. Several ISOs have developed important transmission planning initiatives especially designed to support renewable resources. Some of these initiatives are described below.

The Midwest

The Midwest ISO was among the first to proactively include wind in its transmission planning process, beginning with the first *Midwest ISO Transmission Expansion Plan* in 2003 (MTEP03). MISO studied the transmission planning needs and system impacts of including up to 10,000 MW of wind. For the high wind case, the MTEP03 found marginal cost savings of $215 million compared with the reference case, and $335 million compared with the high-gas case.

For the 2006 MTEP plan, MISO studied the potential system impact of a 20% renewable energy requirement across MISO by 2027. Such a requirement would be equivalent to about 40,000 MW of wind. MISO determined that the 10% renewable scenario would be about 10% more expensive than a reference case but less costly than a higher fuel cost case and an environmental case.

MISO has also been an active participant in the Cap-X process (Capacity Expansion by the Year 2020), a joint initiative of transmission-owning electric utilities in Minnesota and the surrounding region formed to expand the electric transmission grid to meet demand reliably through 2020. Part of the planning includes transmission needed for 2,400 MW of renewables to meet the 10% Minnesota renewable energy objective before the Minnesota Legislature increased the requirement to 25% in 2007 (30% for Xcel Energy) for a 7,300 MW requirement by 2025 for Minnesota.

The Southwest

SPP is home to some of the richest wind resources in the country. The states that comprise SPP include portions of Texas (second-best potential wind resource); Kansas (third-best potential wind resource); Oklahoma (eighth); and Arkansas (27th). The American Wind Energy Association estimates that the SPP region has as much as 150 GW of wind potential. However, much of this wind resource is in remote areas with insufficient transmission capacity. Because of this, planning and building transmission to access these wind resources is drawing interest. One such plan is known as the “X Plan” (Figure 6) that spans western Kansas, Nebraska, Oklahoma, and into the Texas panhandle. The $419 million project consists of two 345 kV transmission lines, with the western portion from Spearville, Kansas, to Potter, Texas, and the eastern portion from Wichita, Kansas, to Oklahoma City, Oklahoma. SPP has designated the western part of the “X Plan” as a reliability transmission project (i.e., it is needed to maintain reliability).

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Figure 6: The "X Plan" in Southwest Power Pool.

Source: Kansas Electric Transmission Authority presentation to the National Council on Electricity Policy, undated. http://www.ncouncil.org/pdfs/pubs/KSElecTransAuthority.pdf (accessed June 8, 2007).

California

The CAISO conducts transmission planning annually with the active participation of the California Public Utilities Commission, the California Energy Commission, electric utilities, and interested stakeholders. The CPUC considers the CAISO's transmission plan to be the transmission roadmap for the state. The CAISO was involved with the Tehachapi Collaborative Study Group that studied transmission alternatives for accessing wind resources at Tehachapi. The CAISO's 2007 Transmission Plan recommended a transmission design and configuration for accessing an estimated 4,350 MW of wind generation in Tehachapi at a cost of $1.8 billion. The CAISO Board of Governors also has endorsed the proposed 500 kV Sunrise Powerlink to access geothermal and solar resources in the Imperial Valley. The CPUC currently is reviewing the Sunrise Powerlink (CAISO 2007).

CAISO proposed, and FERC has preliminarily approved, a transmission framework for locationally constrained resources. This concept applies to all types of generation that is locationally constrained because of its energy source, such as wind generation that must be built in windy areas. Regions with significant renewable generation potential will be identified. Transmission to the region will be designed and constructed prior to the full development of the renewable generation. Costs will be allocated to customers until the renewable generation is built, at which point generation owners assume these costs. FERC has approved the concept, and CAISO currently is working on specific tariff language.

Texas

Texas has initiated a process to designate Competitive Renewable Energy Zones (CREZs) and building transmission to selected CREZs to facilitate the development of thousands of megawatts of wind resources. At the direction of the legislature, ERCOT is conducting studies to identify and evaluate each zone, to determine the cost of required transmission and the cost of integrating the wind resource into the ERCOT system. The Public Utility Commission of Texas will then determine which CREZs and which transmission plans to develop. Initial CREZ designations are expected later this year.

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New England

In 2006, ISO-NE, state regulators, and other stakeholders launched the New England Electricity Scenario Analysis Initiative, an ambitious effort to examine how various ways to meet the region's future electricity needs might affect system reliability, the cost of electricity, and the environment. The objective was to arm the region with information to help make decisions about how to address the sometimes conflicting challenges of the need for new resources, a desire for lower prices, and stronger environmental mandates, such as fulfilling Regional Greenhouse Gas Initiative (RGGI) and Renewable Portfolio Standards requirements.

The resulting report examined the reliability, economic, and environmental performance of a range of long-term resource alternatives for the region. Specifically, the analysis envisioned a peak system demand of about 35,000 MW by 2020 to 2025 and examined the addition of 8,000 MW for seven different resource scenarios. All scenarios assumed that 2,600 MW would reflect the mix of recently proposed power sources in New England. The remaining 5,400 MW represented a large concentration of a certain technology, such as nuclear, renewables, or increased imports, to assess their impact.

Based on the assumptions and other inputs developed with stakeholders, the results of the Scenario Analysis indicated that New England likely will face significant challenges in meeting its allocation of RGGI allowances. Nonetheless, the report's conceptual study of adding an additional 1,500 MW of import transfer capability from New Brunswick into Maine produced positive emissions impacts and contributions to RGGI's goals under the assumption that the sources of power had low emissions (e.g., energy efficiency, wind, certain types of hydro imports and nuclear).

Innovation in Integrating Renewables into the Market

Aside from implementing market rules and practices that recognize the unique characteristics of intermittent renewables, ISOs and RTOs also have led the way with innovations to ensure the reliable integration of renewables into the bulk power systems. One such example is the CAISO's forecasting program, known as the Participating Intermittent Resource Program (PIRP). In 2002, the CAISO became the first regional transmission operator in the United States to offer centralized wind forecasting to predict the output of variable renewable energy generation. To date, only wind generation is enrolled in PIRP. With several proposed large-scale solar projects in California, it is possible for solar to join wind in the PIRP program. In PIRP, the positive and negative imbalances associated with the 10-minute schedules of wind power generators are netted out and settled on a monthly basis, with the notion that these imbalances will cancel out over the month. Any net imbalances at the end of the month, positive or negative, are settled at the weighted average zonal market clearing price. The CAISO also is preparing a comprehensive renewable energy integration plan to aid California in meeting its 20% Renewable Portfolio Standards requirement. NYISO issued a RFP for a day-ahead and real-time wind-forecasting service, and it is scheduled by roughly mid-2008.

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About the ISO/RTO Council

Founded in 2003, the ISO/RTO Council (IRC) is an industry organization comprised of ten Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) in North America, responsible for delivering two-thirds of the electricity consumed in the United States and just over 40 % in Canada.

In addition to coordinating electric generation and transmission across a wide geographic area, ISOs and RTOs provide non-discriminatory transmission access, facilitate competition among wholesale electricity suppliers, and conduct regional planning to ensure a reliable grid for the future.

The IRC works collaboratively to develop effective processes, tools, and methods for improving competitive electricity markets across North America. The IRC's goal is to balance reliability considerations with market practices, resulting in efficient, robust markets that provide competitive and reliable service to electricity users.

This report was compiled by Brendan Kirby of Electric Power Consulting and Kevin Porter of Exeter Associates on behalf of the IRC.

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List of Acronyms

AEP	American Electric Power
AESO	Alberta Electric System Operator
AGC	automatic generation control
AWEA	American Wind Energy Association
BPA	Bonneville Power Administration
CAISO	California Independent System Operator Corporation
CREZ	Competitive Renewable Energy Zones
EIA	Energy Information Agency
ERCOT	Electric Reliability Council of Texas
FCM	forward capacity market
FERC	Federal Energy Regulatory Commission
IESO	Independent Electricity System Operator (Ontario)
ISO-NE	Independent System Operator, New England (ISO New England)
ISO	Independent System Operator
LSE	load-serving entity
MISO	Midwest Independent System Operator
MW	megawatt
MWh	megawatt-hour of energy
NBSO	New Brunswick System Operator
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
PIRP	Participating Intermittent Resource Program
PJM	PJM Interconnection L.L.C.
PSC	Public Service Commission
PUC	Public Utility Commission
REC	renewable energy credit
RTO	Regional Transmission Organization
RPS	renewable portfolio standard
SCE	Southern California Edison
SPP	Southwest Power Pool
WECC	Western Electricity Coordinating Council

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Appendix A: Renewable Portfolio Standards

In general, Renewable Portfolio Standards require load-serving entities to annually meet a specified percentage of their retail sales from eligible technologies that generally (but not always) are limited to renewable energy technologies. Typically, a Renewable Portfolio Standard increases over time, and a penalty may be levied if the RPS target is not met. Nearly all Renewable Portfolio Standards are set by energy, not capacity. In many states, RPS compliance may involve renewable energy credits (RECs). A REC represents one megawatt-hour of renewable energy generation and can be bought, sold, or traded before being used for RPS compliance.

To date, 25 states and the District of Columbia have enacted Renewable Portfolio Standards, and all of them differ in several key aspects, such as resource eligibility, the size of the RPS target, treatment of existing resources compared with new renewable resources, whether RECs are used or not, how RPS noncompliance is treated, and types of flexibility mechanisms for RPS compliance (i.e., banking, multipliers, compliance waivers, etc.) (see Figure A-1). RPS activity has picked up in recent years; 13 RPS policies have been enacted since 2004. Moreover, states often change their RPS policies to increase the RPS targets or add eligible resources or to make other changes. Since 1999, 14 states have changed their RPS policies; eight states have changed their RPS policy more than once.

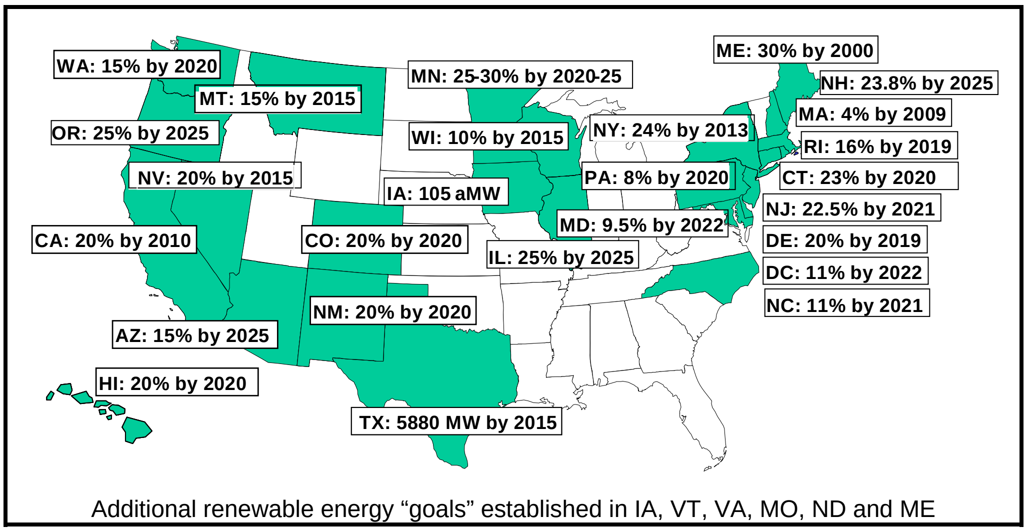

Figure A-1: State Renewable Portfolio Standards Policies for 25 States and DC.
Source: Union of Concerned Scientists

State RPS policies are having a market impact. Black and Veatch, a construction company, estimated that about half of the renewable energy capacity additions from the late 1990s through 2006 have taken place in states with RPS policies, amounting to about 5,500 MW. Over 90% of this capacity is from wind power, although biomass, geothermal and, more increasingly, solar thermal stand to gain from these policies as well. Lawrence Berkeley National Laboratory found that about half of all wind capacity developed between 2001 and 2006 was a result of state RPS policies. The U.S. Energy Information Administration estimates that 7,300 MW of new renewable energy capacity was stimulated by state RPS policies through 2006. The Union of Concerned Scientists estimated that state RPS policies collectively could stimulate as much as 46 GW of renewables by 2020. Conversely, the National Renewable Energy Laboratory estimated that 8,000 to 12,000 MW of new renewable energy capacity will be driven by state RPS policies, in part because of their assumptions that renewable energy capacity additions will occur

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even without a Renewable Portfolio Standard and that cost caps embedded in state RPS policies may restrict the impact of some state RPS policies.

About 40% of load nationwide is covered by a Renewable Portfolio Standard, and although originally implemented first in states implementing retail competition, RPS policies are now being adopted by regulated states such that these policies are about evenly divided between states with retail competition and states with regulated monopolies. Besides mandatory RPS requirements, voluntary renewable energy standards are in place in Illinois, Iowa, Maine, and Vermont.[13]

Of the 25 states and the District of Columbia with RPS policies, 17 are served at least partially by an ISO or RTO. ISOs and RTOs play a pivotal role with regard to the implementation of Renewable Portfolio Standards. Most prominently, they can help with tracking generation or RECs, because ISOs and RTOs have the generation and load data in their central energy management systems that are necessary to help state regulators determine compliance with Renewable Portfolio Standards. Four ISOs and RTOs—ERCOT, ISO-NE, MISO, and PJM —oversee tracking systems or provide operational data used to aid RPS implementation and compliance, and New York is in the process of designing and implementing a tracking system.

What follows is a description of state RPS policies for each ISO and RTO, the activities of each ISO and RTO in relation to Renewable Portfolio Standards and renewables, and the future outlook of renewable energy in each ISO and RTO.

California ISO

Even before CAISO started operating, renewables were already an important presence in California because of aggressive state implementation of the Public Utility Regulatory Policies Act of 1978 and federal and state tax incentives. The state helped launch the U.S. wind industry and had the most installed wind capacity of any state until it was surpassed by Texas in 2006. California also is home to eight parabolic trough solar plants and was the only state with utility-scale concentrating solar projects until the 64 MW Nevada Solar One parabolic trough facility came on line in Nevada in June 2007. Presently, renewable energy accounts for 11% of electricity consumption in California, excluding large hydro (see Table A–1).[14] The California Energy Commission estimates a statewide renewable resource potential of 262,000 GWh annually. Of this, 212,347 GWh is in Southern California Edison's service territory.[15]

[13] Wiser, Ryan; Christopher Namovicz; Mark Gielecki; and Robert Smith. "Renewable Portfolio Standards: A Factual Introduction to Experience from the United States." *Electricity Journal*, April 2007. http://eetd.lbl.gov/ea/EMS/reports/62569.pdf (accessed May 31, 2007).

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Table A–1
Gross System Power in California, 2006, GWh

Fuel Type	In-State	Northwest	Southwest	GSP	GSP%
Coal	17,573	5,467	23,195	46,235	15.7
Large Hydro	43,088	10,608	2,343	56,039	19.0
Natural Gas	106,968	2,051	13,207	122,226	41.5
Nuclear	31,959	556	5,635	38,150	129
Renewables	30,514	1,122	579	32,215	109
Biomass	5,735	430	120	6,285	2.1
Geothermal	13,448	0	260	13,708	4.7
Small Hydro	5,788	448	0	6,236	2.1
Solar	616	0	0	616	0.2
Wind	4,927	244	199	5,370	1.8
Total	**230,102**	**19,804**	**44,959**	**294,865**	**100.0**

Source: Pan, Adam and Jason Orta. *2006 Net System Power*. California Energy Commission, CEC-300-2007-007, April 2007. http://www.energy.ca.gov/2007publications/CEC-300-2007-007/CEC-300-2007-007.PDF (May 31, 2007).

California enacted its 20% Renewable Portfolio Standard by 2017 in 2003 and amended the Renewable Portfolio Standards in 2006 to accelerate the 20% target to 2010. In addition, California is considering setting a statewide goal of 33% renewables by 2020. California has perhaps the most complex Renewable Portfolio Standard in the nation. Utilities are required to annually submit draft renewable resource procurement plans and solicitations for review and approval by the California Public Utilities Commission. Once approved, utilities select bids that meet a least-cost, best-fit test. Utilities must also work with a procurement review group on the Renewable Portfolio Standards solicitations and the bids. If bids exceed a market price reference and funding in the California Energy Commission's New Renewable Resources account is sufficient, utilities can receive supplemental energy payments from the commission to make up the difference. RECs are not allowed for RPS compliance in California until the Western Regional Generation Information System (WREGIS) is in operation and the California Public Utilities Commission and the California Energy Commission determine that other criteria are met. California's Renewable Portfolio Standard allows utilities to bank renewable generation for up to three years, and the amended Renewable Portfolio Standards statute may allow utilities to miss RPS requirements if sufficient transmission is not available and "all reasonable efforts have been made" to provide transmission capacity and to use flexible delivery points.[16] About 35,000 GWh of renewable energy generation will be needed to meet the 2010 RPS requirement.[17] WREGIS began operating in June 2007, and the California PUC has opened a docket on whether to allow retailers to use RECs for complying with the California Renewable Portfolio Standard.

[16] California Public Utilities Code § 399.11. http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=399.11-399.20 (accessed May 31, 2007).

[17] California Public Utilities Commission. *Progress of the California Renewable Portfolio Standard.* April 2007. http://www.cpuc.ca.gov/published/REPORT/66515.htm (accessed May 31, 2007).

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California is rich in renewable resources, but a significant amount of potential renewables are in regions with little or under-developed transmission networks, particularly in southern California. Therefore, transmission will be a critical element towards achieving the California Renewable Portfolio Standards requirements. Table A–2 presents some of the major proposed transmission lines that may be essential for meeting the California Renewable Portfolio Standards requirements.

Table A–2
Significant Proposed Transmission Projects in California

Network Upgrade	Projected Completion Date	Projected Capacity of Upgrade (MW)	Contracted and Short-listed RPS Capacity (MW)
Tehachapi Renewable Transmission Project (TRTP)—SCE	3/2009 – 11/2013	4,500	1,896
Devers-Palo Verde 2, Devers-Valley—SCE	12/2009	1,200	447
Sunrise Powerlink—SDG&E	6/2010	1,000	488
Stirling Solar Dish Upgrade—SCE	TBD	500-850	500+
Green Path North—Citizens, IID, LADWP	2011	1,200	TBD

Source: California ISO, August 2007.

CAISO recently obtained preliminary FERC approval for an innovative “third category” of transmission for locationally-constrained resources, in this case, renewable energy facilities. To be eligible, a facility must be a high-voltage transmission facility, sometimes referred to as a “trunk line” that is designed to provide access for multiple, location-constrained resources within a designated “energy resource area.” Initially, the cost of the high-voltage facility would be spread across all grid users. Upon interconnecting to the completed facility, a generator would be charged a *pro rata* share of the line’s going-forward cost based on the portion of the line’s capacity the generator will use. The cost of the unused capacity of the line would still be assessed to all grid users. Once the facility is constructed, generators of any fuel type would be able to connect to the line. FERC also included a rate cap and a requirement that transmission providers demonstrate interest in the potential transmission capacity from location-constrained generators. Specifically, CAISO proposed, and FERC accepted, that the costs of transmission for locationally constrained resources be capped at 15% of the value of the total net high-voltage transmission assets of all participating transmission owners in CAISO. In addition, a minimum percentage of the capacity of the new transmission (e.g., 25 to 35%) must be subscribed through long-term interconnection agreements, and additional interest (e.g., 25 to 35%) must be expressed in addition to the long-term interconnection agreements. CAISO is expected to file specific tariff provisions and implementation language with FERC by the end of 2007.[18]

[18] Federal Energy Regulatory Commission, California Independent System Operator Corporation. *Order Granting Petition for Declaratory Order*, April 19, 2007. 119 FERC 61,061.

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New York ISO

New York has a 24% by 2013 Renewable Portfolio Standard with an additional 1% to be met from voluntary green power purchases. New York's Renewable Portfolio Standard also contains two tiers: one tier for medium-to-large renewable energy facilities, known as the main tier, and a tier for customer-sited generation facilities. In addition, the New York Renewable Portfolio Standard allows existing renewable energy facilities to petition for inclusion in the Renewable Portfolio Standard if necessary to maintain the facility's operation. New York presently receives 19.3% of its energy from renewables, almost entirely from hydro.

For the main tier, another unique feature of the New York Renewable Portfolio Standardsis that utilities in New York do not actually procure renewable energy generation as RECs. Instead, utilities pay a fee to the New York State Energy Research and Development Authority (NYSERDA), which in turn conducts an auction for RECs. NYSERDA then distributes RECs proportionate to the fees utilities contributed to NYSERDA.[19] NYSERDA has conducted two REC auctions in 2005 and 2007.[20] NYSERDA provides capacity- or performance-based incentives for customer-sited generation facilities.

The NYISO has over 5,000 MW of wind capacity in its interconnection queue.[21] The state is estimated to have a wind resource potential of 7,080 MW.

Before the New York PSC finalized the adoption of the Renewable Portfolio Standard, NYSERDA and the NYISO commissioned a study to assess the grid impacts of 10% wind energy, or about 3,300 MW of wind. The study, conducted by GE Energy Consulting, found that the New York bulk power grid could accommodate that level of wind penetration.

The GE study made certain recommendations that the NYISO is in the process of implementing. The NYISO has a capacity market, and the NYISO gave wind the same capacity value of the wind project's capacity factor, minus maintenance outages. The GE report recommended measuring the capacity factors of a wind project between 1:00 p.m. and 4:00 p.m. between the months of June and August, an approach similar to PJM's. The NYISO adopted this general approach but uses performance between 2:00 p.m. and 6:00 p.m. between June and August for the summer and between 4:00 p.m. and 8:00 p.m. between December and February for the winter capability periods.

GE also recommended that the NYISO implement a centrally administered, day-ahead wind forecasting system. The NYISO issued a RFP for a day-ahead and real-time wind forecasting service in 2007 and plans to have it operational by mid-2008. In the interim, the NYISO uses persistence forecasting (i.e., wind generation in the previous hour is assumed to be the same for the next hour). Although persistence

[19] New York State Energy Research and Development Authority. "About New York's Renewable Portfolio Standard." http://www.nyserda.org/rps/about.asp (accessed May 31, 2007).

[20] New York State Energy Research and Development Authority. "New York's Continued Commitment to Clean, Renewable Energy Could Foster $1.4 Billion of Investments in New York." http://www.nyserda.org/Press_Releases/PressRelease.asp?i=151&d=2007 (accessed May 31, 2007).

[21] Federal Energy Regulatory Commission. *New York Independent System Operator, Inc.: Order Accepting Tariff Revisions.* FERC 118 ¶ 61,068 (January 31, 2007).

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forecasting is somewhat accurate for very short time periods, persistence forecasting is ill-equipped for the longer-term forecasting needed for day-ahead markets.[22]

The NYISO previously exempted up to 500 MW of intermittent generation from over and under generation penalties. In January 2007, with FERC approval, the NYISO raised the limit to 1,000 MW and plans to propose market rules for all intermittent generation later in 2007, regardless of how many intermittent generators are in operation.[23]

Finally, New York is considering establishing a tracking system. Although the NYISO may not administer the system, energy data obtained from NYISO would likely be pivotal to the operation of the tracking system.

PJM Interconnection

PJM serves all or parts of 13 states and the District of Columbia. Of these, Delaware, the District of Columbia, Maryland, New Jersey, and Pennsylvania have state RPS policies, the details of which are outlined in Table A–3. Four of the state RPS policies within PJM have separate set-asides for solar within their Renewable Portfolio Standards. The Union of Concerned Scientists estimates that these five state RPS policies could support about 12,000 MW of existing and new renewable generation by 2020.

Like New England and Texas, PJM has a tracking system, known as the Generation Attribute Tracking System (GATS). GATS is used not only to meet state RPS policies but also state environmental disclosure and fuel disclosure requirements and to help support voluntary bilateral green power markets that focus on renewable energy generation. As of May 2007, GATS has 289 registered renewable energy generators and 303 subscribers. In 2006, PJM-EIS issued over 56 million certificates from GATS, and issued over 17 million GATS certificates for the first three months of 2007.[24]

PJM created a separate subsidiary, known as PJM-GATS, to manage the tracking system apart from the PJM membership. The costs of GATS are paid through a combination of registration fees, volumetric fees imposed on load-serving entities that participate in GATS, and for certificate transfers into certain accounts, although no fee is charged if a load-serving entity is using the certificate to comply with a state RPS requirement.[25] All five states in PJM with a state RPS policy use GATS for tracking compliance, although New Jersey has its own tracking system for solar because the New Jersey Renewable Portfolio Standard requires the solar portion of its standard to be met by in-state solar facilities. In addition, the solar facilities are almost all below the 1 MW minimum threshold that PJM tracks.

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[22] Piwko, Richard; Xinggang Bai, Kara Clark, Gary Jordan, Nicholas Miller and Joy Zimerlin. *The Effects of Integrating Wind Power on Transmission System Planning, Reliability and Operations: Report on Phase 2.* New York State Energy Research and Development Authority, 2005. http://www.nyserda.org/publications/wind_integration_report.pdf (accessed May 31, 2007).

[23] Federal Energy Regulatory Commission. *New York Independent System Operator, Inc.: Order Accepting Tariff Revisions.* FERC 118 ¶ 61,068 (January 31, 2007).

[24] PJM. *GATS Status Update*, May 22, 2007. http://www.pjm-eis.com/subscriber/downloads/20070522-gats-subscriber.pdf (accessed May 29, 2007).

[25] PJM. *Generator Attribute Tracking System Refresher Training*, May 22, 2007. Available at http://www.pjm-eis.com/subscriber/downloads/20070522-gats-refresher-training-2007.pdf (accessed May 29, 2007).

PJM does not charge imbalance penalties for schedule deviations, such as the energy imbalance penalties set out in Order 888 (market rules that account for the unique characteristics of renewables, which are available in most ISOs/RTOs). Because wind is a small percentage of PJM's energy mix, PJM takes wind as a price taker in the real-time market and does not require wind generators to bid into the day-ahead market, except for wind generation that is an installed capacity resource. PJM imposes an operating reserve charge for differentials greater than 5 MW to recover the costs from decommitting already committed generators. On average, the operating reserve charge is about $2–$3/MWh.

PJM has an installed capacity market. For wind, PJM measures the capacity value of wind generation between 3:00 p.m. and 6:00 p.m., inclusive, between the months of June and August. PJM will use a three-year rolling average, as adjusted for unforced outages for both individual wind projects and for all wind projects to determine a class average. Because wind generation data is relatively scarce, PJM has used a proxy value of 20% until more wind generation data are available. Wind generators that decide to be an installed capacity resource must bid at least 20% of their energy in the day-ahead market. PJM also has streamlined and accelerated interconnection projects for generation projects below 20 MW.

Because renewable energy, most particularly wind, accounts for a small percentage of PJM's energy mix, PJM has not commissioned an integration study similar to New York, California, and elsewhere. PJM conducted a workshop to learn more about wind forecasting in 2005 but is still researching and considering whether to require the use of wind forecasting. Some wind forecasting is done by market participants in bidding at least the 20% minimum into the day-ahead market.

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Table A–3
State Renewable Portfolio Standards Policies in PJM

State	Class	RPS	Eligible Technology	Non-Compliance Penalties (per MWh)
DE	**N/A**	20% by 2009 with 2.005% from solar	Solar, wind, ocean tidal, ocean thermal, fuel cells powered by renewable fuels, small hydroelectric facilities, sustainable biomass, anaerobic digestion, and landfill gas	$50 for non-solar, $250 for solar. Noncompliance fee increased to $80/MWh for non-solar and $300 for solar if noncompliance fees paid in previous years.
DC	**Tier 1**	11% by 2022	Solar, wind, biomass, landfill gas, wastewater-treatment gas, geothermal, ocean, and fuel cells fueled by "tier one" resources	$25
	Tier 2	2.5% by 2022	Hydropower, municipal solid waste	$10
	Solar	0.386% by 2022	Solar	$300
MD	**Tier I**	9.5% by 2022 2% from solar	Solar, wind, qualifying biomass, methane from the anaerobic decomposition, geothermal, ocean, fuel cells powered by methane or biomass, and small hydroelectric plants	$20 for non-solar Tier 1, $45 for solar in 2008 and declining to $5 by 2023
	Tier 2	2.5% by 2018	Hydroelectric power, waste-to-energy facilities, and poultry-litter combustion	$15
PA	**Tier 1**	8% by 2020 with 2% from solar	Photovoltaic energy, solar-thermal energy, wind, low-impact hydro, geothermal, biomass, biologically-derived methane gas, coal-mine methane, and fuel cells	$45 for non-solar; twice the market price of solar credits for solar
	Tier 2	10% by 2020	Waste coal, distributed generation (DG) systems, demand-side management, large-scale hydro, municipal solid waste, pulping process and wood-manufacturing byproducts, and integrated combined coal-gasification (ICCG) technology	$45
NJ	**Class I**	17.88% by 2021	Solar, wind, wave or tidal action, geothermal energy, landfill gas, anaerobic digestion, fuel cells using renewable fuels, and certain sustainable biomass	$50
	Class II	2.5% by 2021	Small hydro < 30 MW, and resource recovery	$50
	Solar	2.12% by 2021	Solar	$300

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Ontario

As of 2005, Ontario receives just over 40% of its generating capacity from nuclear, 23% from hydro and other renewables, 19% from coal, about 15% from natural gas and cogeneration, and just under 2% from energy conservation (see Table A–4).[26] Ontario installed over 400 MW of wind power in 2006 after beginning the year with about 15 MW of wind.

A study of Ontario's wind power potential found 7,000 to 9,000 MW of wind potential within either 10 kilometers of high-voltage transmission lines or five kilometers of distribution stations. However, the study also noted that 95% of Ontario's wind resources are not accessible by Ontario's existing transmission system.[27]

Table A–4
Ontario's Generating Capacity

Technology	Capacity
Nuclear	14,000 MW
Hydro and Other Renewables	7,855 MW
Coal	6,434 MW
Gas and Cogeneration	4,976 MW
Conservation	675 MW

Source: Ontario Ministry of Energy. "Backgrounder: Ontario's Energy Mix." http://www.energy.gov.on.ca/index.cfm?fuseaction=english.news&back=yes&news_id=134&backgrounder_id=105 (accessed June 8, 2007).

The Ontario government set a goal of a 5% increase in the province's capacity coming from renewable energy by 2007 (1,350 MW) and 10% (2,700 MW) by 2010.[28] Ontario also has set a wind capacity target of 5,000 MW by 2020 that would represent about 15% of Ontario's expected generating capacity.[29] The Ontario Power Authority suggested an upper limit of 15% until further experience is gained with large-scale wind integration. Overall, Canada has put in place a production incentive of 1 cent/kWh (Canadian), payable to the generator to stimulate 4,000 MW of renewable energy capacity by 2011. It is expected that this target will be met by 2010.[30]

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[26] Ontario Ministry of Energy. "Backgrounder: Ontario's Energy Mix." http://www.energy.gov.on.ca/index.cfm?fuseaction=english.news&back=yes&news_id=134&backgrounder_id=105 (accessed June 8, 2007).

[27] Bailey, Diane. "Ontario Sees Wind as Generation Future," *Windpower Monthly*, February 2006, pp. 40-41.

[28] Ontario Ministry of Energy. "McGuinty Government Gives Green Light to Renewable Energy Projects." November 24, 2004. http://www.energy.gov.on.ca/index.cfm?fuseaction=english.news&news_id=82&body=yes (accessed June 8, 2007).

[29] Hornung, Robert. "An Overview of Canada's Rapidly Expanding Wind Energy Market." Presentation to *Windpower 2007*, Los Angeles, California, June 4, 2007.

[30] Hornung, Robert. "An Overview of Canada's Rapidly Expanding Wind Energy Market." Presentation to *Windpower 2007*, Los Angeles, California, June 4, 2007.

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The 2004 Ontario Electricity Restructuring Act allows the province to solicit renewable energy proposals and sign energy contracts. On June 24, 2004, the Ontario Ministry of Energy issued a Request for Proposals (RFP) for approximately 300 MW of renewable energy capacity for Ontario. The 10 winning projects were announced on November 24, 2004, and totaled 395 MW. On April 19, 2005, Ontario issued a 1,000 MW renewable energy RFP, and by the end of the year, signed contracts with eight wind projects representing 955 MW and a small hydro project for 20 MW.[31] By the end of 2005, Ontario had contracted for 1,300 MW of renewable generation, consisting of 12 wind projects, three hydro projects, two landfill gas projects, and one biogas project. Another RFP, perhaps as much as 1,000 MW, is expected in 2007.[32]

Ontario also implemented a standard offer contract for renewable energy projects at 10 MW or less that are interconnected to the distribution grid. The standard-offer contract is similar to feed-in tariff laws, which have been used in Europe to promote renewable energy and pay a flat rate of about 11 cents/kWh (Canadian). So far, 22 contracts representing over 140 MW were awarded for a total of C$336 million.[33] Of these, 14 are wind projects (129.5 MW), three are bioenergy (10.2 MW), two are small hydro (2.45 MW), and three are solar photovoltaic projects (22.9 kW).

Transmission constraints and the planned addition of large-scale generation around the Bruce Peninsula has proven to be a significant limiting factor in adding more renewable energy generation in Ontario. Contracts for 725 MW of wind capacity that are due to come on line in 2008, as well as plans for refurbishing and restarting two idle nuclear units for 1,500 MW by as early as 2009, means that the transmission capability on the Bruce Peninsula will be inadequate. A new 500 kV transmission line is planned but may not be ready by 2009.[34] As a result, the Ontario Power Authority is limiting new generation in the area until new transmission is built.[35]

In 2006, the Ontario Power Authority released a report, in collaboration with the Independent System Operator of Ontario and the Canadian Wind Energy Association, assessing the potential grid impacts of large-scale wind development. The report, done by GE Energy Consulting, examined five scenarios: 2009 demand plus 1,310 MW of wind capacity and 2020 load with four wind scenarios of 5,000 MW, 6,000 MW, 8,000 MW, and 10,000 MW of wind capacity. The report found that incremental regulation needs are relatively modest at all levels of projected megawatt capacity and could be handled with existing resources. System load-following requirements can be met with up to 5,000 MW of wind, but additional load-following resources may be necessary with higher levels of wind capacity. Similarly, the report found that an increase in operating reserves is likely at higher levels of wind capacity. Finally, the report determined that the increase in hourly and multi-hourly variability is no more than 10%, even with the addition of 10,000 MW of wind, but that more one-hour ramping capability is required to handle extreme one-hour and multi-hourly changes in wind generation.[36]

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[31] Ontario Ministry of Energy. "McGuinty Government Approves New Green Power Projects." November 21, 2005. http://www.energy.gov.on.ca/index.cfm?fuseaction=english.news&body=yes&news_id=115 (accessed June 8, 2007).

[32] Hornung, Robert. "An Overview of Canada's Rapidly Expanding Wind Energy Market." Presentation to *Windpower 2007*, Los Angeles, California, June 4, 2007.

[33] Ontario Power Authority. *Laying the Foundation for a Sustainable Electricity Future: 2006 Annual Report.* March 2007. http://www.powerauthority.on.ca/Storage/40/3587_OPA_2006AR_23Mar07(WEB).pdf (accessed June 8, 2007).

[34] Bailey, Diane. "Policy for Distributed Wind Takes a Hit." *Windpower Monthly*, January 2007, pp. 34-35.

[35] Bailey, Diane. "First Contracts for Distributed Wind." *Windpower Monthly*, April 2007, pp. 52-53.

[36] Van Zandt, Devin; Lavelle Freeman; Gao Zhi; Richard Piwko; Gary Jordan; Nicholas Miller; Michael Brower. *Ontario Wind Integration Study*. October 2006. http://www.uwig.org/OPA-Report-200610-1.pdf (accessed June 8, 2007).

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New Brunswick

In July 2006, New Brunswick established a Renewable Portfolio Standard requiring 1% of all energy to come from new renewables in 2007, increasing by 1% each year until 2016, when the Renewable Portfolio Standard tops out at 10%. Eligible sources include biogas, biomass, solar, hydro, and wind. The dominant utility, New Brunswick Power, has issued a 300 MW renewable energy RFP, and has nearly 100 MW of wind capacity contracted for immediate development. Because of New Brunswick's small load, the province is tentatively concluding it cannot necessarily incorporate more wind until advances are made in reducing and mitigating the impacts of the production variability and forecast errors. NBSO is pursuing those advances, many of which require greater coordination and cooperation between system operators.

Southwest Power Pool

Except for Texas, no state in SPP has a Renewable Portfolio Standard. Because SPP includes only a small part of Texas, the state's Renewable Portfolio Standard will be addressed in the section on ERCOT.

SPP is home to some of the richest wind resources in the country. The states that comprise SPP include Texas (second-best potential wind resource); Kansas (third-best potential wind resource); Oklahoma (eighth); and Arkansas (27th).[37] The American Wind Energy Association estimates that the SPP region has as much as 150 GW of wind potential.[38]

However, much of this wind resource is in remote areas with insufficient transmission. Because of this, planning and building transmission to access these wind resources has drawn interest. One such plan is known as the "X Plan" and spans western Kansas, Nebraska, Oklahoma, and into the Texas panhandle (see Figure A-2). The $419 million project consists of two 345 kV transmission lines, with the western portion from Spearville, Kansas, to Potter, Texas, and the eastern portion from Wichita, Kansas, to Oklahoma City, Oklahoma.[39] SPP has designated the western part of the "X Plan" as a reliability transmission project (i.e., it is needed to maintain reliability). The other part of the X Plan is an economic transmission project (i.e., transmission that would access other generating resources, lower customer costs, or both). SPP's operating rules state that project sponsors pay for such economic transmission

[37] Wind potential estimates from the American Wind Energy Association's Wind Project Data Base at their web site, www.awea.org (accessed May 29, 2007).

[38] American Wind Energy Association. *Designation of a Heartland Transmission Corridor*. December 2006. http://www.awea.org/policy/regulatory_policy/transmission_documents/Expansion/AWEA_Transmission_Corridors_12_1_2006.pdf (accessed June 8, 2007).

[39] Kansas Electric Transmission Authority presentation to the National Council on Electricity Policy, undated. http://www.ncouncil.org/pdfs/pubs/KSElecTransAuthority.pdf (accessed June 8, 2007).

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projects, although they may receive transmission credits. If the line is later found to have reliability benefits, some of the costs may be recovered through SPP's reliability cost-allocation process that spreads 35% of the costs to all load and the remainder to beneficiaries of the new transmission, as determined by modeling.

Figure A–2: The "X Plan" in Southwest Power Pool.

Source: Kansas Electric Transmission Authority presentation to the National Council on Electricity Policy, undated.
http://www.ncouncil.org/pdfs/pubs/KSElecTransAuthority.pdf
(accessed June 8, 2007).

SPP does not operate a day-ahead power market such as PJM, ISO-NE, or NYISO. Instead, SPP administers a regional open-access transmission tariff, ensures regional electric reliability, monitors regional scheduling, and conducts regional transmission planning. In February 2007, SPP implemented a regional, offer-based energy imbalance market.[40]

SPP has its own method of determining the capacity credit of wind that is used for long-term planning. SPP does not have a market for installed capacity and instead uses capacity value for long-term planning. For wind, SPP determines the capacity value monthly. SPP begins by examining the highest 10% of load hours in the month. Wind generation from those hours is then ranked from high to low. The wind capacity value is selected from this ranking, and it is the value that is exceeded 85% of the time (the 85th percentile). Up to 10 years of data are used if available. For the wind plants studied in the SPP region, the capacity values ranged from 3% to 8% of rated capacity.[41]

SPP also has explored whether to re-rate constrained transmission lines to allow more wind power onto the lines. Because wind generation is primarily at off-peak times and the transmission carrying capability is rated at peak times, it is thought that more wind generation potentially could be carried on transmission

[40] Southwest Power Pool. "Southwest Power Pool Launches Energy Imbalance Services Market," February 1, 2007. Available at http://www.spp.org/publications/SPP_Market_Launch_Feb_01_2007.pdf (accessed May 29, 2007).

[41] Milligan, Michael; Porter, Kevin. *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*. National Renewable Energy Laboratory, NREL/CP-500-38062. Available at http://www.nrel.gov/docs/fy05osti/38062.pdf (accessed May 29, 2007).

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paths than conventional rating criteria would suggest. SPP analyzed potential high wind resource areas and measured whether the wind resource could be correlated to load. SPP also would require wind companies to install real-time monitoring equipment.[42] SPP's concept is still under consideration and has not proceeded to implementation.

Midwest ISO

Of the 15 states the Midwest ISO serves, four states have established Renewable Portfolio Standards: Illinois, Iowa, Minnesota, and Wisconsin. (See Table A-5) Minnesota and Wisconsin increased their Renewable Portfolio Standards in 2007 and 2006, respectively. Currently, MISO has about 1,880 MW of wind in its footprint, and another 500 to 1,000 MW of wind is expected in 2007. MISO estimates that another 13,800 MW of wind generation will be added within the footprint by 2027. MISO is estimated to have 400,000 MW of wind resource potential.

MISO does not schedule wind in the day-ahead market but instead takes wind generation in real-time market because it is generated as a price taker. MISO does not have a capacity market and therefore does not evaluate the capacity value of wind, although wind does qualify as a capacity resource in meeting the MISO's resource adequacy requirements**.** Wind generation is assigned a 15% capacity credit in generation-expansion planning.

MISO was among the first to proactively include wind in its transmission planning process, beginning with its first *Midwest ISO Transmission Expansion Plan* (MTEP) in 2003. MISO studied the transmission planning needs and system impacts of including up to 10,000 MW of wind. For the high-wind case, the 2003 MTEP found marginal cost savings of $215 million compared with the reference case, and $335 million compared with the high-gas case.[43]

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[42] Caspary, Jay. "Mitigation of SPP Transmission Constraints in Higher Wind Areas." Presentation before the Utility Wind Interest Group (UWIG) Fall Technical Workshop, October 24, 2006, Oklahoma City, Oklahoma.

[43] Midwest ISO. *MTEP-03: Midwest ISO Transmission Expansion Plan*. June 19, 2003. http://www.midwestiso.org/publish/Document/3e2d0_106c60936d4_-75120a48324a/MTEP%202002-2007%20Board%20Approved%20061903.pdf?action=download&_property=Attachment (accessed June 8, 2007).

Table A–5
State RPS Policies in the Midwest ISO

State	Class	RPS	Eligible Technology	Penalties (per MWh)
WI	**N/A**	10% Statewide by 2016 (Varies by utility)	Tidal and wave action, fuel cells using renewable fuels, solar, wind, geothermal, hydropower less than 60 MW, and biomass	Range from $5,000 to $500,000
IL		10% by 2015 and 25% by 2025. At least 75% is to come from wind power.	Wind power, solar energy (thermal and photovoltaic), biodiesel, crops and untreated, unadulterated organic waste biomass, trees and tree trimmings, and hydropower from existing facilities.	The cost of procuring renewable energy resources is capped to a rate impact of 0.5% in any one year.
IA	**N/A**	105 MW	Photovoltaics, wind, biomass, hydro, municipal solid waste	Utilities are in full compliance, and no penalties were ever specified.
MN	**Xcel Energy**	25% by 2020	Wind	PSC may order compliance via building facilities, purchasing renewable power, or buying RECs. If still noncompliant, PSC may impose financial penalties not to exceed the costs of compliance.
	Xcel Energy	5% by 2020	Solar, hydroelectric facilities less than 100 MW, hydrogen and biomass, which includes landfill gas, anaerobic digestion, and municipal solid waste.	PSC may order compliance via building facilities, purchasing renewable power, or buying RECs. If still noncompliant, PSC may impose financial penalties not to exceed the costs of compliance.
	Other Utilities	25% by 2020	Solar, wind, hydroelectric facilities less than 100 MW, hydrogen and biomass, which includes landfill gas, anaerobic digestion, and municipal solid waste.	PSC may order compliance via building facilities, purchasing renewable power, or buying RECs. If still noncompliant, PSC may impose financial penalties not to exceed the costs of compliance.

For the 2006 MTEP plan, MISO studied the potential system impact of a 10% renewable energy requirement across MISO by 2016. For the 2008 MTEP plan, which is in progress, MISO is studying a 20% wind energy scenario across MISO footprint. Such a requirement would be equivalent to about 40,000 MW of wind capacity. MISO determined that the 20% renewable scenario would be about 10% more expensive than a reference case but less costly than a case with higher fuel costs and an environmental case (see Figure A-3). Preliminary results show that the benefits obtained by loads and generation would be able to support the annual costs of transmission to distribute energy efficiently and have a substantial amount left to support the justification for building the transmission for the simulation year 2021.

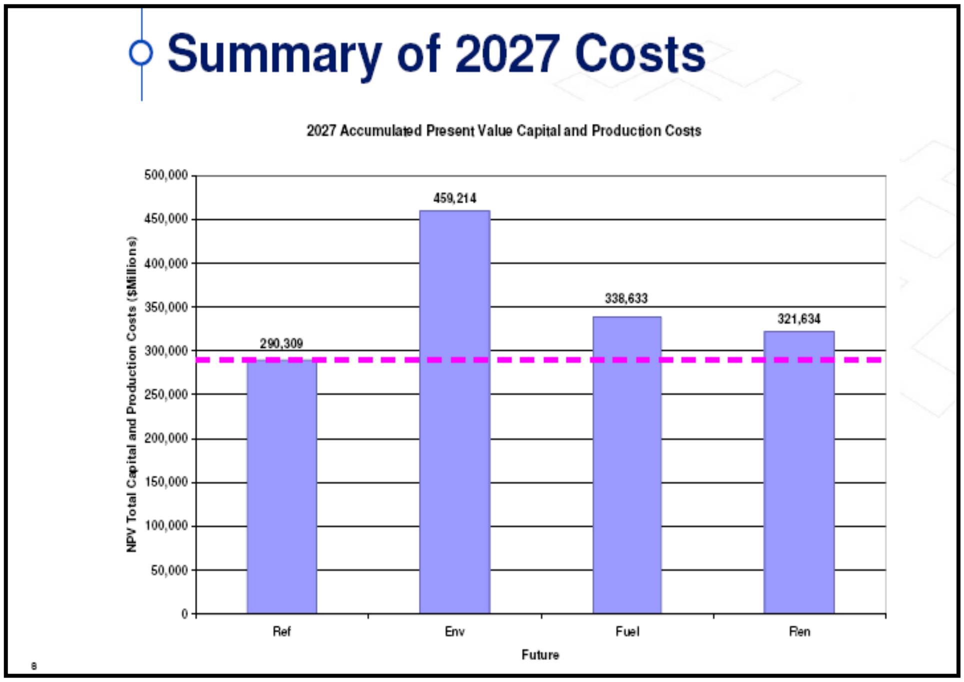

Figure A-3: Estimated costs of various scenarios in the Midwest ISO's 2008 MTEP plan.

As part of its study, the MISO incorporated a series of 765 kV transmission lines to transmit the wind power into higher electricity cost areas in the Mid-Atlantic states in PJM. More specifically, the transmission was placed in the lower-cost areas within MISO to the highest price areas in PJM. Figure A-4 illustrates the placement of the transmission and the wind power.

MISO's preliminary analysis, as illustrated in Figure A-5, suggests possible LMP price reductions of about 10% within MISO and about 5% within PJM. MISO is exploring the concept further and may conduct a more detailed study, sponsored by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, with PJM, SPP, and other participants if adequate funding can be obtained.

MISO also has participated in the CAP-X transmission planning initiative involving Minnesota's electric utilities. MISO also participated in Minnesota's 20% wind integration study that was released in late 2006. The study found that with the transmission that is planned and with some control area consolidation, Minnesota could incorporate 20% wind energy adequately and without impact on electric reliability.[44]

[44] Enernex Corporation. *Final Report—2006 Minnesota Wind Integration Study*. November 30, 2006. http://www.uwig.org/windrpt_vol%201.pdf (accessed May 29, 2007).

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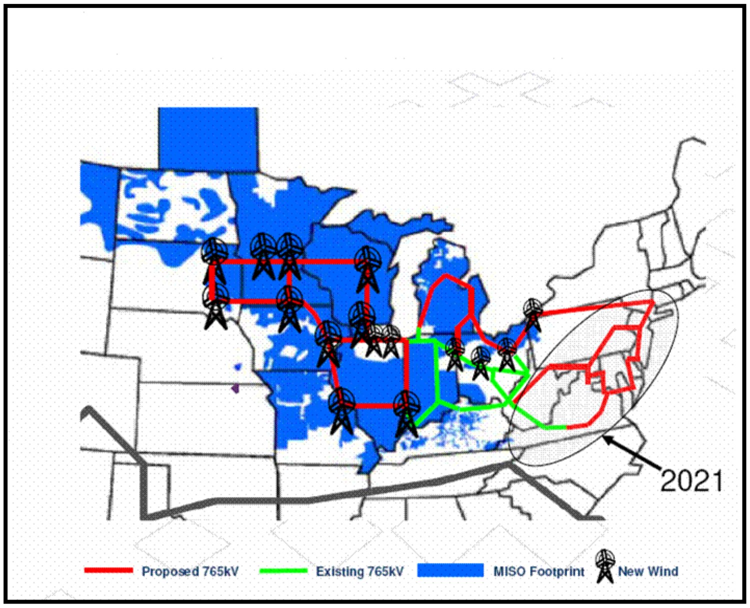

Figure A-4: Placement of transmission and wind power included in the Midwest ISO's 2008 MTEP preliminary studies.

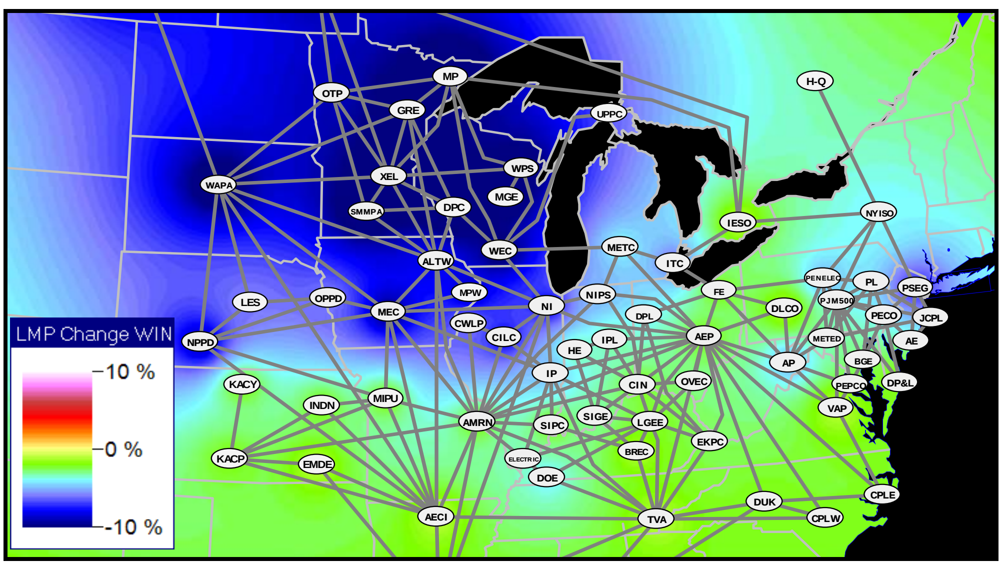

Figure A-5: Potential LMP reductions for a 20% renewable energy requirement in MISO 2008 preliminary studies.

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Electric Reliability Council of Texas

Texas has perhaps the most successful state Renewable Portfolio Standard in the country. Enacted in 1999, the Texas Renewable Portfolio Standard is unique in that it is based on capacity rather than a percentage of electric energy. The Texas Renewable Portfolio Standard required 2,880 MW of new and existing renewable energy capacity by 2009, a requirement that was exceeded in 2006. Texas also surpassed California as the state with the most installed capacity of wind power in 2006. Wind power represents 78% of the 3,263 MW of renewable energy capacity in Texas and has accounted for 97% of the renewable energy capacity that was installed in Texas since the enactment of the Texas Renewable Portfolio Standard.[45]

Eligible renewable energy technologies under the Texas Renewable Portfolio Standard include solar, wind, geothermal, hydroelectric, wave or tidal energy, or biomass or biomass-based waste products, including landfill gas, installed after September 1999. The Renewable Portfolio Standard applies to all retail energy providers including municipal and cooperative utilities. Retail energy providers that do not meet RPS targets are subject to a penalty of the lesser of $50/MWh or 200% of the market price of RECs. The capacity targets are converted to energy by the average capacity factor of renewable energy resources that participate in the Texas Renewable Portfolio Standard.

As part of implementing the Texas Renewable Portfolio Standard, the Public Utility Commission of Texas (PUCT) instituted a REC tracking program in July 2001 that will continue through 2019 and appointed ERCOT as the administrator. ERCOT, in turn, contracted with Automated Power Exchange to design the REC tracking program. The REC tracking system creates accounts for participants to track the production, sale, transfer, purchase, and retirement of RECs. Credits can be banked for three years, and all renewable additions have a minimum of 10 years of credits to recover over-market costs. A 2004 amendment changed the formula for calculating final REC purchase requirements, added a mechanism to account for corrections to retail sales data, and allows the program administrator of the REC-trading program to petition for deadline changes under certain circumstances. The PUCT may impose a ceiling on the price of RECs and may suspend the Renewable Portfolio Standard to ensure grid reliability.

In 2005, the Texas Legislature enacted SB 20, strengthening the Texas Renewable Portfolio Standard to increase the renewables requirement to 5,880 MW by 2015, with 500 MW of that to come from non-wind eligible renewable energy technologies. Even this target is likely to be surpassed before the 2015 deadline; if the projects scheduled for completion in 2007 come on line, the level of renewable capacity in Texas will be roughly 5,240 MW by the end of 2007. About 2.1% of the electricity generated in Texas during 2006 came from renewable energy resources, up from 1.5% for 2005.

SB 20 also introduced the concept of competitive renewable energy zones, or CREZs. Under SB 20, the Public Utility Commission of Texas (PUCT) is authorized to identify areas with sufficient renewable energy potential, identify the transmission facilities that could serve the area, and establish the need for new transmission facilities serving the area, even if no specific renewable generation projects exist or are under construction. The CREZs indicate areas within Texas with high clean energy potential; transmission infrastructure is to be built between the CREZs and load centers. In addition, SB 20

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[45] Public Utility Commission of Texas. *Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas.* January 2007. Available at http://www.puc.state.tx.us/electric/reports/scope/2007/2007scope_elec.pdf (accessed May 30, 2007).

authorized the PUCT to order a utility to construct or expand transmission to help meet the Texas Renewable Portfolio Standard and required the PUCT to approve RPS-related transmission applications within 181 days, or the application is approved. The impetus for this approach comes primarily from prior experience with wind projects in west Texas, where the availability of transmission was insufficient. The CREZ approach is intended to address the “chicken and egg” problem where transmission is not built until it is needed for new generation and developers are reluctant to build without sufficient transmission available. Once a CREZ has been identified, utilities are guaranteed cost recovery of the transmission built to serve that area.

In 2006, the PUCT instituted rules laying out guidance on how it will designate CREZ areas. One of the factors that the commission would consider in designating CREZs would be the financial commitments of wind project developers to building in the zone, and the rule includes mechanisms to minimize the risk that transmission facilities built to serve CREZs would be underutilized. The 2006 rule does not designate any CREZ. Rather, it establishes the procedure for the contested dockets in which designations will be made and establishes what will be considered a financial commitment. The rule requires ERCOT to study the wind energy production potential statewide and establishes criteria for designating CREZs.

The commission anticipates issuing its first order later in 2007. Once the CREZ order is entered, the affected transmission utilities will have one year to prepare their applications for Certificates of Convenience and Necessity (CCNs). The CCN proceeding is expected to take six months after which construction would take another one to two years. As a result, transmission from the first group of CREZs is expected to be available by 2010 or 2011.

ERCOT has also hired GE Energy Consultants to examine the quantity of ancillary services that are needed to ensure grid reliability with increasing amounts of wind power. Four scenarios are being studied. The first scenario includes 5,000 MW of wind, with the locations of wind projects derived from current and near-future wind project locations. The second and third scenarios include 10,000 MW of wind but in different locations. One of the two scenarios includes more wind from the coastal region of Texas, while the other has no coastal wind but more wind in the panhandle region. The fourth scenario has 15,000 MW of wind in the panhandle region. The study should be available by the end of 2007.

ISO New England

All six states that comprise ISO-NE have RPS policies, although Vermont has a Renewable Portfolio Standard goal that does not turn into a Renewable Portfolio Standard requirement until 2013. Because Vermont’s requirement will convert to an RPS only if utilities do not meet incremental load growth with renewable energy and energy efficiency, Vermont generally is not considered to have a Renewable Portfolio Standard and is not included in Table A–6 below. A description of each state’s Renewable Portfolio Standard policy is provided in Table A–6.

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Table A–6
State RPS Policies in ISO New England

State	Class	RPS	Eligible Technology	Penalties (per MWh)
MA	**N/A**	4% by 2009, 1%/yr increase thereafter until date determined by State	Solar; wind; ocean thermal, wave, and tidal; fuel cells using renewable fuels; landfill gas; and low-emission, advanced technology biomass	$55.13, adjusted for inflation
RI	**N/A**	16% by 2020	Solar, wind, ocean, geothermal, small hydro <30 MW, eligible biomass, fuel cells using renewables	$50, adjusted for inflation
NH	**Class I**	16% by 2025	Wind, geothermal, hydrogen from biomass or methane, ocean, methane gas, eligible biomass	$57.12
	Class II	0.3% by 2025	New solar after January 1, 2006	$150
	Class III	6.5% by 2025	Existing biomass and methane plants that began operating before 2006	$28
	Class IV	1% by 2025	Existing small hydro < 5 MW and began operations before 2006	$28
ME	**N/A**	30% by 2000[(a)]	Fuel cells, tidal power, solar arrays and installations, wind power installations, geothermal installations, hydroelectric generators, biomass generators, or municipal solid waste	License revocation or fines, or payments into a renewable energy R&D fund, based on the market price difference between eligible and non-eligible generation
CT	**Class I**	20% by 2020	Solar, wind, new sustainable biomass, landfill gas, ocean thermal power, wave or tidal power, low-emission advanced renewable-energy conversion technologies, and new small (<5 MW) run-of-the-river hydropower	$55/MWh
	Class II	3% by 2020	Trash-to-energy facilities, biomass facilities not included in Class I and certain hydropower facilities (<5 MW)	$55/MWh
	Class III	4% by 2020	Customer-sited CHP generation	$55/MWh

(a) In addition to the 30% RPS requirement, Maine requires suppliers to obtain a percentage of the electricity they supply to customers to come from new renewable capacity resources. The renewable capacity requirement increases from 1% in 2008 to 10% in 2017.

ISO-NE was the first ISO or RTO to include a certificate tracking system that tracks emissions and generation attributes for the generation of electric energy from all resources not just renewables. Like PJM, all states in ISO-NE use the New England Power Pool's Generation Information System for compliance with individual state policies on Renewable Portfolio Standards, environmental disclosure, and emissions portfolio standards.

Depending on the size of the facility, ISO-NE schedules intermittent power producers differently:

- Wind capacity under 5 MW is treated as a "settlement-only resource." These resources do not

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have to bid in the day-ahead market; instead, they generate into the grid at real-time and get the real-time nodal price. The capacity value of these resources is considered the same as the capacity factor of the project, minus forced outages.

- Wind capacity over 5 MW is considered an "intermittent power resource." These resources can submit bids into the day-ahead market, but if they do not, they must self-schedule into the reoffer period. As with settlement-only resources, the capacity value of these resources is considered the same as the capacity factor of the project, minus forced outages.[46]

ISO-NE recently commissioned a wind potential report for its region. The report determined that the maximum potential is about 94,000 MW without accounting for environmental, recreational, or other screening criteria (Table A–7). Of this, 60,000 MW (about 64%) is onshore and the remainder is offshore. The report also determined that the typical capacity value for wind would be 19% in the summer and 41% in the winter for onshore sites, and 26% in the summer and 46% in the winter for offshore sites.[47]

Table A–7
Maximum Theoretical Wind Generation

Zone	MW
Maine	39,379
Vermont	7,997
New Hampshire	5,598
SEMA	4,552
WCMA	1,432
Rhode Island	488
NEMA	226
Connecticut	175
Offshore Shallow	25,679
Offshore Deep	8,295
Total	**93,821**

Source: Levitan and Associates. Technical Assessment of Onshore and Offshore Wind Generation Potential in New England. May 1, 2007.

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[46] David LaPlante. "Integrating Wind Resources into New England's Competitive Wholesale Electricity Markets." Presentation to the Utility Wind Interest Group Fall Technical Workshop, October 27, 2004, Albany, New York.

[47] Levitan and Associates. *Technical Assessment of Onshore and Offshore Wind Generation Potential in New England*. May 1, 2007. http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/may212007/levitan_wind_study.pdf (accessed May 31, 2007).

Appendix B: Aggregation Insights from ERCOT's February 24, 2007, Wind Event

February 24, 2007, provides an excellent example of the benefits and limitations of aggregation for wind in a geographically large ISO. Wind production was fairly high throughout ERCOT that morning. Aggregate wind production was over 2,000 MW at 9:00 a.m.; about 70% of the total 2,900 MW state wind capacity. A strong weather pattern increased winds further throughout the western part of the state forcing many wind turbines to shut down as the morning progressed. Individual wind plants can be seen shutting down in Figure B-1.

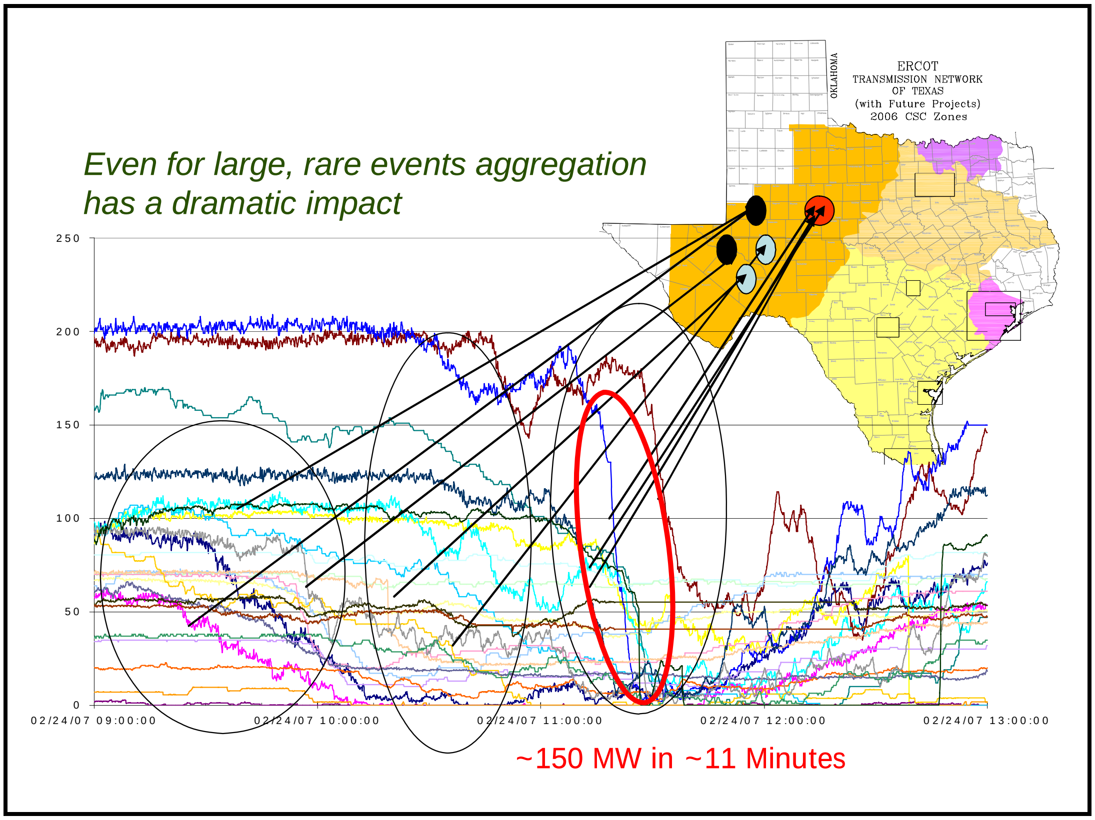

Figure B-1: A strong weather pattern increased winds on the morning of February 24, 2007, throughout western Texas, forcing many wind turbines to shut down.

Source: Stuart Nelson.

One 200 MW wind plant dropped 150 MW (75%) of its nameplate capacity in 11 minutes—a fairly dramatic ramping event. Given this single-plant behavior, power system planners and operators are legitimately concerned about the possible ramping impact that large amounts of wind can have on their system. If all the wind plants experienced the wind event simultaneously, the power system would have experienced at 1,500 MW drop in 11 minutes. Instead, the large drop occurred over a period of two hours giving the power system enough time to respond to the drop and make up for the energy loss with other generators. Fortunately, aggregation helps.

Clearly this single-plant behavior dropping 75% in 11 minutes is much slower than what is exhibited by a single turbine which can drop from full output to zero nearly instantaneously. Looking at the aggregate

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behavior of all ERCOT wind plants (Figure B-2) shows that aggregation continued to slow even the extreme wind event as it is scaled up to cover much of Texas.

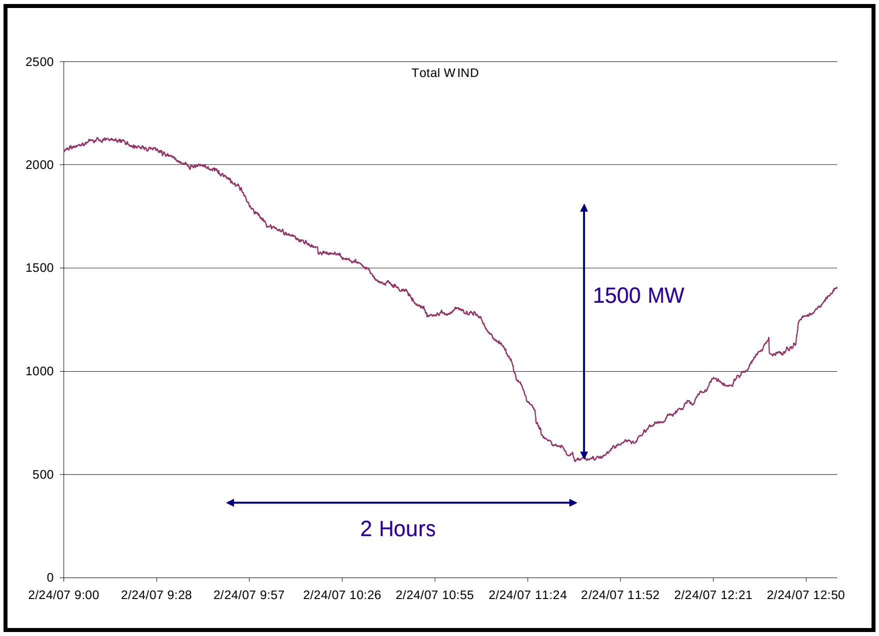

Figure B-2: Aggregate wind fleet exhibits a larger total megawatt drop but a slower ramp rate.

The total wind fleet dropped 10 times as much generation (~1,500 MW), but it took 10 times as long (~120 minutes). It was certainly not a contingency event and therefore was not eligible to rely on contingency reserves. Increasing the size of the wind fleet and the size of the power system it is integrated with will increase the size of potential large ramping events, but it will not necessarily increase the ramp rate as dramatically. Aggregation over a geographically large ISO or RTO mitigates the physical impact of even an extreme wind event.

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