PUBLIC SERVICE COMMISSION OF WISCONSIN

DRAFT

STRATEGIC ENERGY ASSESSMENT

ENERGY 2018

610 NORTH WHITNEY WAY
MADISON, WISCONSIN

JUNE 2012
DOCKET 5-ES-106

TO THE READER

This is the seventh biennial draft Strategic Energy Assessment (SEA) issued by the Public Service Commission of Wisconsin (Commission), an independent state regulatory agency, whose authority and responsibilities include regulatory oversight of electric service in Wisconsin.

The SEA provides a picture of past and future electric energy needs and sources of supply. It brings to light issues that may need to be addressed to ensure the availability, reliability, and sustainability of Wisconsin's electric energy capacity and supply.

UNDERSTANDING THE SEA – KEY TIPS AND PROCESSES

While the Commission is required to prepare this technical document for comments by parties involved in the electric industry, it also intends that the SEA be available to the general public having an interest in reliable, reasonably priced electric energy. To assist the general public, definitions of key terms and acronyms used within the electric industry and this report are included in the appendix of this document.

The Commission is required to hold a public hearing before issuing a final SEA. A copy of the notice providing information on the hearing will be available for review on the Commission's website at: http://psc.wi.gov.

The Commission must make an environmental assessment on the draft SEA before the final report is issued. It will be available on the Commission's website at least 30 days prior to the public hearing.

Public comments will be used to prepare the final SEA. The Commission encourages all interested persons to comment on the content of this report during the 90-day comment period, which begins with the mailing of this draft SEA. Additional information on how to submit a comment will be provided in the Notice of Hearing and Request for Comments.

Questions regarding the process or requests for additional copies of the draft SEA may be directed to Amy Pepin at (608) 267-7972. Questions from the legislature and the media may be directed to Kristin Ruesch at (608) 266-9600.

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STRATEGIC ENERGY ASSESSMENT

2012-2018 Electricity Issues

STUDY SCOPE

The Public Service Commission of Wisconsin (Commission) is required by Wis. Stat. § 196.491(2) to prepare a biennial Strategic Energy Assessment (SEA) that evaluates the adequacy and reliability of Wisconsin's current and future electrical capacity and supply.

The SEA intends to identify and describe:

- All large electric generating facilities for which an electric utility or merchant plant developer plans to commence construction within seven years;
- All high-voltage transmission lines for which an electric utility plans to commence construction within seven years;
- Any plans for assuring that there is an adequate ability to transfer electric power into or out of Wisconsin in a reliable manner;
- The projected demand for electric energy and the basis for determining the projected demand;
- Activities to discourage inefficient and excessive energy use;
- Existing and planned generation facilities that use renewable energy sources; and
- Regional and national policy initiatives that could have direct and material impacts on Wisconsin's energy supply, delivery, and rates. Recently, the United States Environmental Protection Agency (EPA) put forth air emission regulations that could affect the reliability of electric service. The Commission is actively participating in the ongoing rules development.

The SEA is required by statute to assess:

- The adequacy and reliability of purchased generation capacity and energy to serve the needs of the public;
- The extent to which the regional bulk-power market is contributing to the adequacy and reliability of the state's electrical supply;
- The extent to which effective competition is contributing to a reliable, low-cost, and environmentally sound source of electricity for the public; and
- Whether sufficient electric capacity and energy will be available to the public at a reasonable price.

The SEA must also consider the public interest in economic development, public health and safety, protection of the environment, and diversification of energy supply sources.

STUDY METHODOLOGY AND LIMITATION

Under statutory and administrative code requirements, every electricity provider and transmission owner must file specified historic and forecasted information. The draft SEA must be distributed to interested parties for comments. Subsequent to hearings and receipt of written comments, the final SEA is issued. In addition, an Environmental Assessment, which includes a discussion of generic issues and environmental impacts, will be issued in connection with the SEA.

This seventh SEA covers the years 2012 through 2018. During the past year, eleven large Wisconsin-based investor-owned utilities, cooperatives, municipal electric companies, and other electricity and transmission providers submitted historic information regarding statewide demand, generation, out-of-state sales and purchases, transmission capacity, and energy efficiency efforts. In addition, these entities provided forecasted information through 2018.

The SEA is an informational report that provides the public and stakeholders with information about relevant trends, facts, and issues affecting the state's electric industry. The SEA is not a prescriptive report, meaning that the ideas, facts, projects, and policy discussions contained in this report will not be used as the exclusive basis for ordering action by the Commission. State law inhibits such action, specifically Wis. Stat. § 196.491(3)(dm). Should a specific topic warrant further attention with the intent of Commission action, the Commission must take additional steps as authorized by law.

EXECUTIVE SUMMARY

DEMAND AND SUPPLY OF ELECTRICITY

- The recent economic downturn has translated into lower peak demand growth in Wisconsin. Wisconsin utilities forecast between 0.5 percent and 1.3 percent annual load growth through 2018. This is similar to the 1.0 percent forecast from the last SEA.
- The increased presence of renewable projects in Wisconsin continues to change the generation mix proportions in the state.
- Wisconsin's primary energy source is coal. The state's generation mix consists of more renewable energy than in recent years.

MARKET ANALYSIS AND PLANNING RESERVE MARGINS

- In earlier SEAs published in the 1990s, reserve margins had been a concern. Actual reserve margins fell to less than 10 percent on multiple occasions in that decade, prompting the Commission to mandate that utilities maintain a higher planning reserve margin. The recent economic downturn, coupled with the state's generation construction in the past several years, created additional capacity; however, planning reserve margins have declined slightly since the last SEA.
- Wisconsin's planning reserve margins are forecasted to remain above 13.6 percent through 2018. The planning reserve for the critical 2013-2014 period is 20-22 percent.
- While Wisconsin is enjoying sufficient capacity, the other half of the power picture – moving energy from the generation source to customers – is an ongoing challenge. The Commission is currently participating in multiple regional transmission initiatives focused on transmission planning.

RATES

- Energy rates continue to increase across customer classes both in Wisconsin and the Midwest. Rate increases are generally driven by sales decline, transmission, generation and renewable investments, increased federal regulation of pollutants, fuel price volatility and purchased power costs, as well as the high fixed-cost nature of the utility business. In Wisconsin this particularly is the case because the state is at the end of a major generation construction cycle.
- Rate increases can be frustrating for Wisconsin consumers who undertake efforts to conserve energy. Proactive customers can mitigate some bill impacts from rate increases with energy conservation and energy efficiency.
- The Commission must continue to investigate ways to mitigate energy rate increases to ensure Wisconsin remains competitive in a global marketplace.

ENERGY EFFICIENCY AND RENEWABLE RESOURCES

- The Commission continues to work on examining the funding and structure of the energy efficiency and renewable resource programs in Wisconsin under Wis. Stat. § 196.374. The Commission will continue to pursue cost-effective strategies to meet energy efficiency and renewable resource program goals as set forth in that statute.
- State statutes[1] require Wisconsin's electric providers to sell a certain percentage of renewable energy. Approximately 10 percent of all electricity sales in Wisconsin must be from renewable resources by 2015. Wisconsin is well on its way toward achieving this standard. All electric providers and aggregators were Renewable Portfolio Standard (RPS) compliant as of the latest full data year on this topic (2010), as over 6 percent of all electrical energy sold in Wisconsin was generated from renewable resources.

FEDERAL POLICY PROPOSALS

- The Commission will continue to monitor developments with the implementation of EPA rules and their impacts on utilities, including the costs associated with compressed compliance periods for these EPA rules, including the Cross State Air Pollution rule. Wisconsin utilities will have to respond with new or retrofitted generation facilities that meet all emission restrictions, and the Commission will give these impacts careful consideration when reviewing upcoming rate and construction cases. The Midwest Independent Transmission System Operator, Inc. (MISO) has indicated compliance region-wide in its footprint may be as high as $33 billion.
- The Federal Energy Regulatory Commission (FERC) issued Order 1000 on July 21, 2011, to restructure FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. The Commission will continue to work with MISO and other states to fully participate in this process.
- One of the broadest transmission expansion planning efforts that may have an impact on Wisconsin is funded by a U.S. Department of Energy (DOE) grant; the Eastern Interconnection States' Planning Council (EISPC). This effort was initially led by former Wisconsin Commissioner Lauren Azar, and the Commission continues to have an active leadership role in this planning effort.

[1]Wis. Stat. § 196.378(2)

ELECTRIC DEMAND AND SUPPLY CONDITIONS IN WISCONSIN

Overview

An electricity provider is defined for SEA purposes in Wisconsin Administrative Code as any entity that owns, operates, manages, or controls or who expects to own, operate, manage, or control electric generation greater than 5 megawatts (MW) in Wisconsin. Figure 1 shows generators greater than 9 MW. Electricity providers also include those entities providing retail electric service or that self-generate electricity for internal use with any excess sold to a public utility.

Major retail electricity providers and/or transmission owners that submitted demand and supply data for this SEA include: American Transmission Company LLC (ATC), Great Lakes Utilities (GLU), Madison Gas and Electric Company (MGE), Manitowoc Public Utilities (MPU), Northern States Power-Wisconsin (NSPW) (d/b/a Xcel Energy, Inc. (Xcel)), Superior Water, Light and Power Company (SWL&P), Wisconsin Electric Power Company (WEPCO) (d/b/a We Energies), Wisconsin Power and Light Company (WP&L) (d/b/a Alliant Energy), and Wisconsin Public Service Corporation (WPSC).

These providers were required to include supply and demand data for any wholesale requirements that they may have under contract. This action streamlined data reporting and reflected current market activities. Demand and supply data were also provided by Dairyland Power Cooperative (DPC) and Wisconsin Public Power, Inc. (WPPI) on behalf of their member cooperatives and municipal utilities.

Figure 1: Map of Major Electric Generation Facilities in Wisconsin (capacity greater than 9 megawatts)

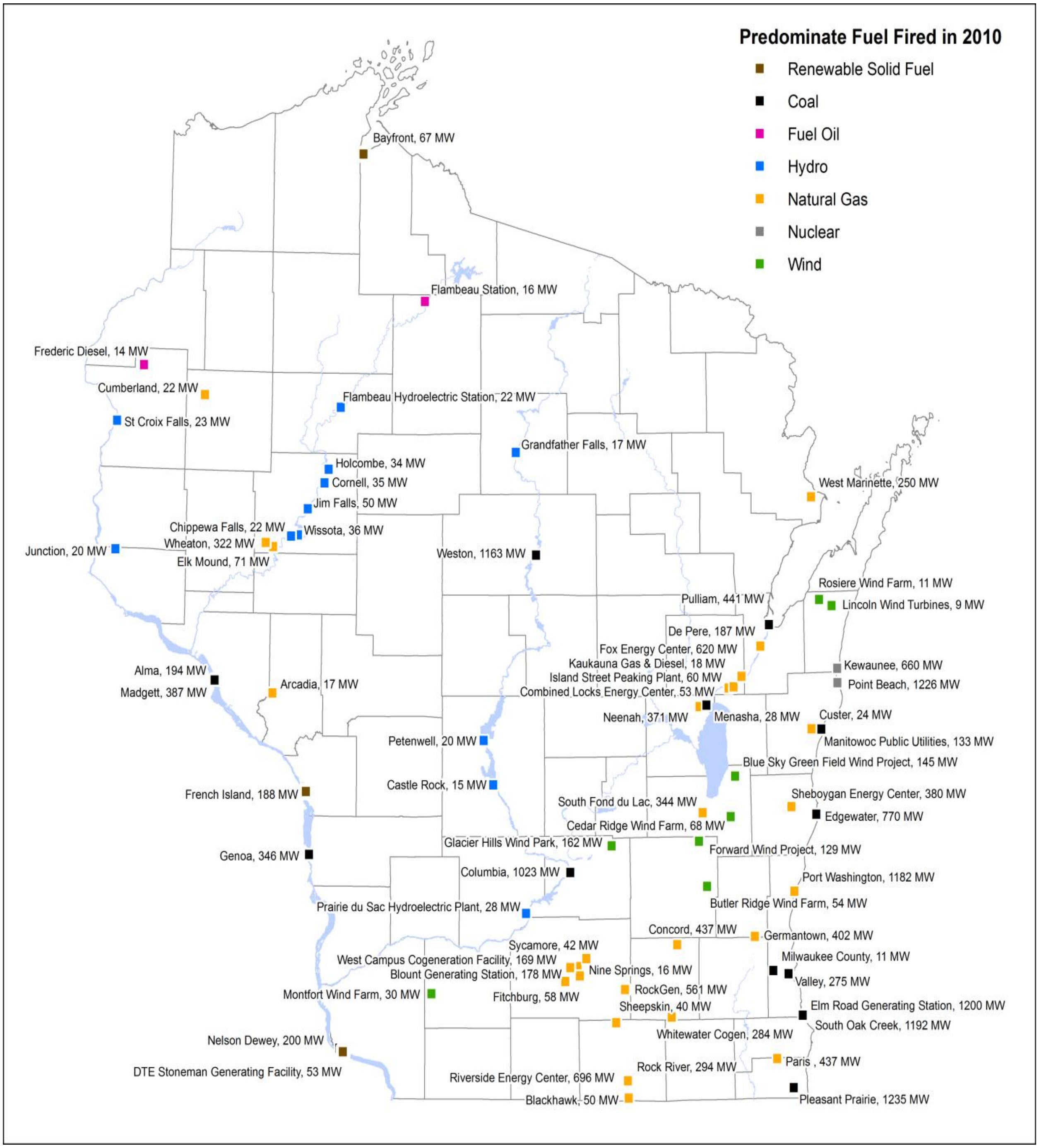


Table 1 shows the aggregated responses of the entities providing data for this SEA. The current planning reserve margin requirement for the Midwest Independent Transmission System Operator, Inc. (MISO) footprint is 17.4 percent; yet this margin is affected by diversity factors. Diversity factors take into account that peak load will likely occur on different days or at different hours within the MISO footprint.

After considering diversity factors, a planning reserve margin of 11.9 percent for each load serving entity is sufficient by MISO's standards to meet demand while maintaining reliability. Data for later years should be considered preliminary, because of the longer-term outlook and the very nature of contracting for supply arrangements.

Table 1: Aggregated Response of Entities Providing Data for this SEA

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Summer Peak Electric Demand (MW)							Forecasted Planning Values			
Date of Peak Load	June 23	August 12	July 20							
Peak Load Data and Forecast [non-coincident]	13,705	14,102	14,811	14,457	14,522	14,665	14,827	14,954	15,128	15,262
Direct Load Control Program	(31)	(53)	0	(216)	(210)	(210)	(216)	(212)	(212)	(213)
Interruptible Load	(20)	(16)	(88)	(660)	(612)	(616)	(663)	(666)	(666)	(669)
Capacity Sales Incl. Reserves	573	542	567	649	582	538	545	546	582	582
Capacity Purchases Incl. Reserves	(664)	(562)	(606)	(613)	(614)	(555)	(545)	(555)	(565)	(575)
Miscellaneous Demand Factors	(131)	(132)	(127)	(138)	(138)	(138)	(73)	(73)	(73)	(73)
Adjusted Electric Demand	13,432	13,882	14,557	13,479	13,530	13,684	13,875	13,994	14,193	14,315
Electric Power Supply (MW)										
Owned Generating Capacity [in, or used, for Wis. cust.]	13,265	13,156	13,490	13,652	13,592	14,112	14,383	14,376	14,570	14,565
Merchant Power Plant Capacity Under Contract [in, or used, for Wis. cust.]	4,015	3,937	3,660	3,599	2,992	2,328	2,102	1,817	1,813	1,807
New Owned or Leased Capacity/Additions	15	99	158	32	562	59	90	52	85	465
Net Purchases W/O Reserves	(1,593)	(1,277)	(1,646)	(687)	(213)	(215)	(92)	(90)	(52)	(49)
Miscellaneous Supply Factors	(220)	(330)	(520)	(415)	(352)	(348)	(267)	(149)	(285)	(250)
Electric Power Supply	15,482	15,586	15,143	16,181	16,581	15,937	16,216	16,006	16,131	16,538
Calculated Data										
Operating Reserve Margin	15.3%	12.3%	4.0%							
Planning Reserve Margin				20.0%	22.6%	16.5%	16.9%	14.4%	13.6%	15.5%
Transmission Data										
Resources Utilizing PJM/WUMS-MISO Interface	296	296	211	246	246	246	246	246	246	246

Source: Aggregated utility data responses, docket 5-ES-106

The lower operating reserve margin for 2011 is driven primarily by the "net purchases w/o reserves" row of data. In 2007 and prior years, Wisconsin's utilities were net purchasers overall; however, 2008 began a period where the utilities, on a statewide basis, were net sellers. Sales of electric power from Wisconsin utilities remained high in 2011, resulting in net sales of 1,646 MW. Because sales result in a reduction of the amount of reserves available, the 4 percent operating reserve margin value for 2011 likely understates the supply adequacy for Wisconsin in that particular year. Future forecast years suggest fewer expected net sales compared to 2011; realistically however, the decision to enter contracts to sell excess capacity is likely to be weighed by the utilities in real time.

Examining both peak demand figures for the recent past, and reserve margin forecasts in the future, confirm that Wisconsin has largely operated with a healthy level of reserves during the summer peak in recent history and is expected to continue to do so into the near future. Reserve margin forecasts for 2012 and 2013 are at least 20 percent, and are expected to remain above 13.6 percent through 2018.

Utilities' Perspectives – Peak Demand and Supply

DEMAND

The Commission compiled substantial information on peak electric demand and energy use for this report. Demand is a measure of instantaneous use measured in megawatts (MW). Energy is a measure of electricity volume used in megawatt hours (MWh) over a period of time. Demand for electricity fluctuates both throughout the day and throughout the year. In any day there are peak hours of demand. In the summer, the demand usually has one peak in the afternoon hours. In the winter, it is common to have a morning and an evening peak. Over the course of a year, demand for electricity is higher in the summer, lowest in the spring and autumn "shoulder" months, and a smaller peak occurs in the winter. Table 2 shows historic monthly peaks since 2001 and forecasted monthly peaks.

The peak load data presented in Tables 1 and 2 do not necessarily show the same MW because different utilities may have different months in which their highest peak occurs. Table 1 shows the total of each utility's maximum peak within the year; Table 2 shows the maximum within a month. For example, if utility A has peaks of 100 MW in July and 80 MW in August, and utility B has peaks of 90 MW in July and 120 MW in August, Table 1 would show that the peak is 220 MW for the year, but Table 2 would show peaks of 190 MW for July and 200 MW for August.

Table 2: Assessment of Electric Demand and Supply Conditions—Monthly Non-Coincident Peak Demands, MW

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Historical												
2001	10,300	10,032	9,722	9,179	9,742	11,800	13,575	13,870	10,898	9,684	9,805	10,268
2002	10,286	9,965	10,111	9,924	10,381	12,782	13,518	13,454	13,211	10,445	10,080	10,857
2003	10,739	10,498	10,291	9,602	9,048	12,725	13,319	13,694	11,937	10,136	10,450	11,302
2004	10,924	10,384	10,091	9,400	10,273	12,486	12,958	12,437	12,161	9,902	10,557	11,478
2005	11,127	10,678	10,433	9,610	10,000	14,020	13,832	14,323	13,224	11,912	10,833	11,581
2006	10,622	10,556	10,174	9,550	11,527	12,559	15,006	14,507	11,060	10,320	10,909	11,553
2007	10,958	11,419	10,682	9,946	11,343	13,834	14,163	14,461	13,693	12,033	11,091	11,503
2008	11,249	11,167	10,437	9,899	9,583	12,283	13,256	12,883	13,111	10,216	10,279	11,438
2009	11,273	10,681	10,246	9,209	9,606	13,694	11,051	12,260	10,846	9,454	9,944	11,075
2010	10,671	10,226	9,611	9,030	12,490	12,495	13,069	14,098	11,662	9,608	10,170	11,101
2011	10,547	10,615	9,841	9,340	10,678	13,558	14,712	13,979				
Forecasted												
2011									12,369	10,285	10,409	11,159
2012	11,046	10,667	10,289	9,835	10,462	13,226	14,333	14,091	12,422	10,311	10,438	11,194
2013	11,092	10,806	10,341	9,872	10,513	13,304	14,416	14,158	12,482	10,338	10,447	11,236
2014	11,220	10,928	10,450	9,978	10,610	13,456	14,565	14,303	12,602	10,432	10,531	11,331
2015	11,330	11,054	10,593	10,097	10,709	13,655	14,720	14,467	12,795	10,582	10,660	11,446
2016	11,431	11,074	10,692	10,205	10,786	13,796	14,864	14,605	12,922	10,667	10,737	11,536
2017	11,550	11,291	10,813	10,315	10,899	13,963	15,034	14,782	13,065	10,762	10,830	11,653
2018	11,676	11,408	10,917	10,431	11,004	14,110	15,180	14,920	13,191	10,860	10,913	11,750

Source: Aggregated utility data responses, docket 5-ES-106

Using the projections provided by the entities submitting data for this SEA, this pattern of winter and summer peaks is expected to continue into the future. While actual demand will remain dependent upon weather, the overall statewide trend is expected to show continued growth in peak demand. The recent recession has had a significant effect on energy sales in the short-term, though the long-term effect remains less clear. After an increase of almost 2.5 percent from 2010 to 2011, which appears to largely be the result of a hotter-than-normal summer in 2011, utilities estimate increases in non-coincident peaks to be between approximately 0.5 and 1.3 percent. Non-coincident peak refers to the sum of two or more peak loads on a system that do not occur in the same time interval. Peak demand is much more responsive to weather than total energy use is, and it is not clear at this time that the recession will have the same percentage impact on peak demand that it has on total energy sales. In the last SEA, docket 5-ES-105, Wisconsin utilities forecasted approximately 1.0 percent growth per year through 2016.[2] The current SEA shows similar forecasts for peak demand growth.

Programs to Control Peak Electric Demand

Wisconsin utilities have two forms of peak load management: direct load control and interruptible load. Peak load management involves removing load from the system at times when utility resources for generation are not able to meet customer demand for energy. These programs were traditionally expected to be used primarily in the summer months, usually on very hot days when demand for electricity is at its highest. In recent years, under certain circumstances, when the winter peak demand for electricity outpaced available generation, these programs have been used to assure a balance between demand and available supply.

Direct load management gives the utilities the ability to take electric demand, such as residential air conditioners, off the system. When utilities implement direct load control, affected customers who volunteered to participate in the program receive a credit on their utility bill. Prior SEAs and Table 1 show that direct load control has been used sparingly. From 2009 through 2011, up to 53 MW of direct load control were called upon. As shown in Table 3 below, the MW of direct load control available to utilities is much greater than what was called upon.

[2] These are utility forecasts; Commission staff does not do an independent demand or energy forecast.

Table 3: Available Amounts of Programs and Tariff to Control Peak Load, MW

Year	Direct Load Control (MW)	Interruptible Load (MW)
Historical		
2001	185	637
2002	200	582
2003	186	554
2004	193	629
2005	225	693
2006	282	830
2007	246	776
2008	222	707
2009	170	597
2010	202	689
2011	215	694
Forecasted		
2012	216	660
2013	210	612
2014	210	616
2015	216	663
2016	212	666
2017	212	666
2018	213	669

Source: Aggregated utility responses and previous SEA reports

The second form of load management is the use of interruptible load for industrial customers. An industrial customer choosing an interruptible load tariff receives a lower electric energy rate in cents per kilowatt-hour (kWh) by agreeing that load may be interrupted during periods of peak demand on the system. A utility will notify an industrial customer on an interruptible load tariff that its load will be taken off the system at a specific time. Again, the actual MW of load that is interrupted in a given year is less than the MW of load that is covered by interruptible tariffs. Despite these tariff details, industrial customers view interruptions as a decrease in quality of service.

In any given year, the need to utilize this form of load control will depend upon generation supply that is available on the days when peak demand happens or when available generation is tight due to planned or unexpected (forced) outages. By 2018, interruptible load is expected to be approximately 4.0 percent of projected electric power supply. Given the disconnect between the availability of load management tools and their limited use, the Commission may explore this area in the future.

Peak Supply Conditions – Generation and Transmission

As indicated in Table 4, the 2012 planning reserve margin is 20.0 percent. Even with the growth in peak summer demand indicated by the utilities through 2018, planning reserve margins are expected to remain above the 14.5 percent requirement through 2015.

Table 4: Forecast Planning Reserve Margins from SEA[3]

Table 4: Forecast Planning Reserve Margins from SEA							
Planning Year	**Final SEA 2000**	**Final SEA 2002**	**Final SEA 2004**	**Final SEA 2006**	**Final SEA 2008**	**Final SEA 2010**	**Draft SEA 2012**
2001	18.0						
2002	17.4						
2003		19.1					
2004		20.9	18.3				
2005			17.4				
2006			15.0				
2007			16.1	18.2			
2008			12.8	18.9	30.9		
2009			10.0	16.4	16.3	11.7	
2010			11.0	17.5	18.7	24.1	
2011				17.2	20.9	26.1	
2012				17.4	18.5	25.8	20.0
2013					14.4	24.9	22.6
2014					11.0	20.1	16.5
2015						18.7	16.9
2016						15.1	14.4
2017							13.6
2018							15.5
Note: The SEA was expanded to cover seven years of forecast data in 2004; prior SEAs only examined two years							

Source: Table 1 and previous SEA reports

In Appendix A of this report, Table A-1 shows new generation facilities and upgrades expected to be in operation or under construction by 2018. Table A-2 describes new transmission lines, and Table A-3 in Appendix A includes the utilities' listed retirements.

CURRENT GENERATION FLEET

Figures 2 and 3 indicate the mix of generation available to Wisconsin utilities for the current SEA. Roughly 44 percent of Wisconsin's nameplate capacity is available through coal, with natural gas

[3] The Planning Reserve Margin (PRM) as shown in Table 4 for 2016 and 2017 is less than the 14.5 percent required under the Commissions' October 10, 2008 order in Docket 5-EI-141. This is a result of some of the electric power supply numbers reflecting uncertainty in the area of lease generation. If it is assumed that all Wisconsin utilities comply with the Commission required 14.5 percent PRM, the state-wide PRM is never less than 15.5 percent through 2018.

combustion turbine and combined cycle facilities providing over one third of Wisconsin's nameplate capacity. The increased presence of renewable projects in Wisconsin continues to change generation mix proportions in the state.

Figure 2: Wisconsin Generation Capacity by Fuel, January 2011 – includes generating units operated by IOUs, cooperatives, municipals, non-utilities, and merchants; total in service nameplate and uprate capacity (MW)

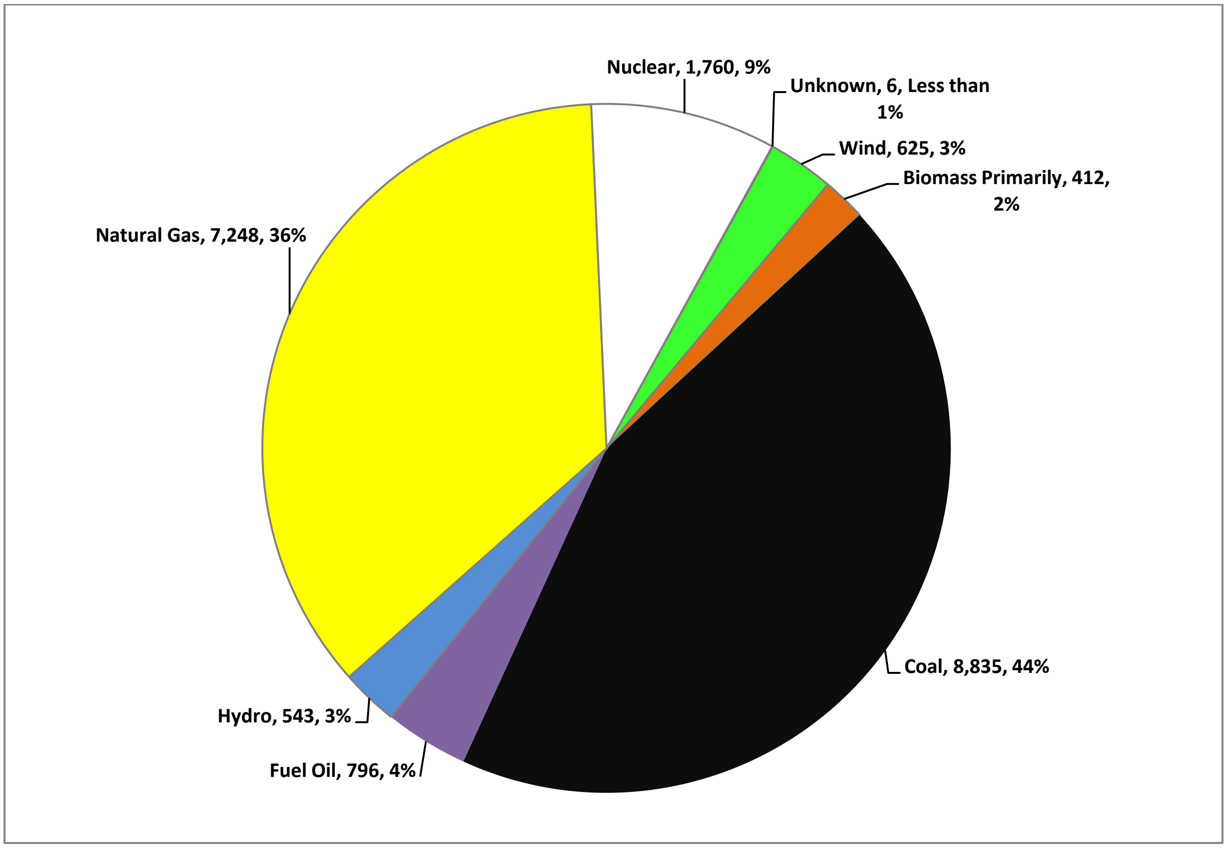
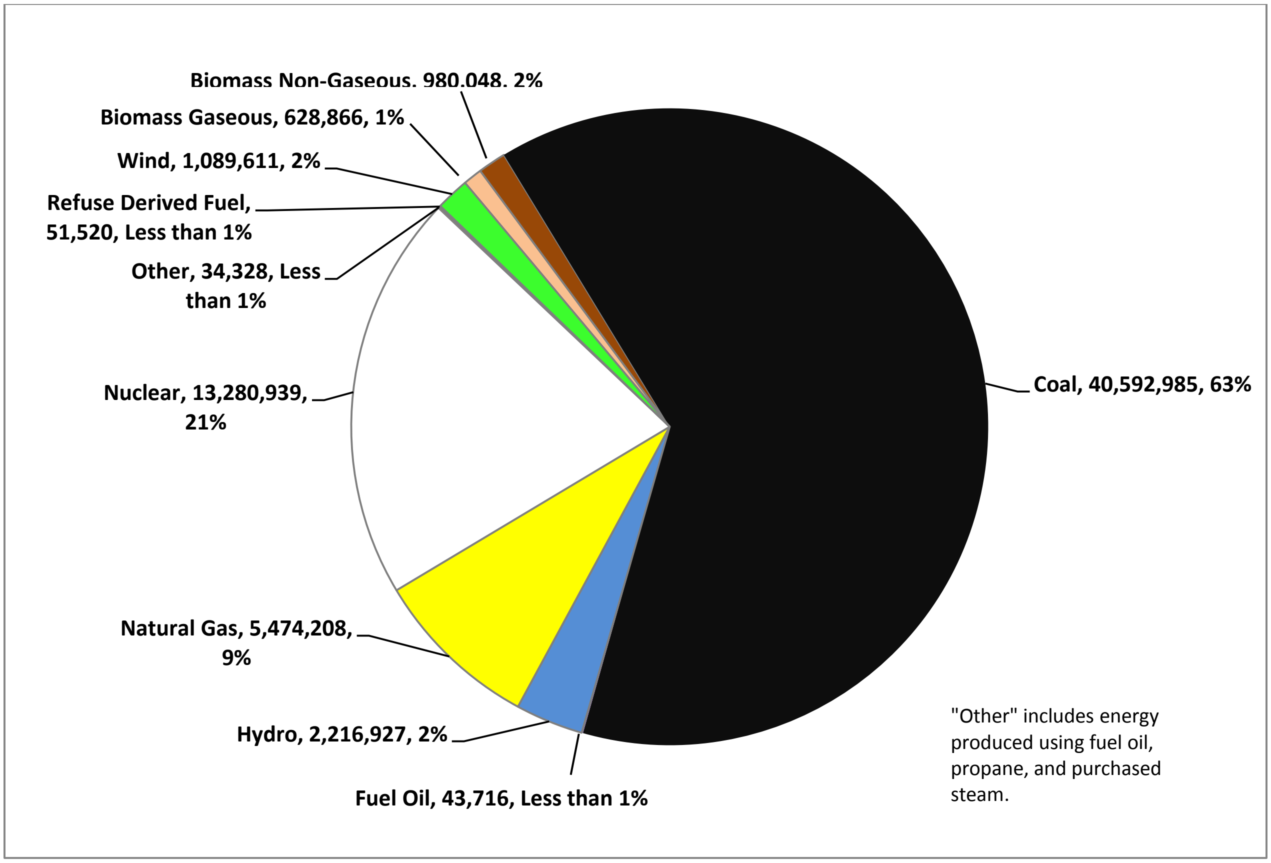


Figure 3 indicates actual generation by fuel from most recent data. Wisconsin's actual energy generation proportions differ greatly from the state's nameplate capacity. Approximately two thirds of actual generation is supplied from coal and only about 9 percent of actual generation comes via natural gas sources.

Figure 3: Wisconsin Energy Generated by Fuel, 2010 – includes generating units operated by IOUs, cooperatives, municipals, non-utilities, and merchants (MWh)



NEW GENERATION[4]

Between the beginning of 2010 and this draft SEA, over 1,800 MW (approximately 360 MW is wind) of additional new generation capacity for Wisconsin utilities has been brought into service. Units that became operational during that time include: Elm Road Units 1 and 2, the Bent Tree Wind Project, Glacier Hills Wind Park, Marshfield Combustion Turbine, and the Point Beach Unit 1 and 2 uprates. While past SEAs have reflected a multi-year expansion period in which Wisconsin addressed previous capacity challenges, the current SEA continues a notable slowing in new planned generation seen in the 2016 SEA.

Wisconsin utilities have prioritized generation construction and enjoy a healthy planning reserve margin and adequate capacity. They continue to balance newly added capacity against an economic downturn and subsequent slowing of energy demand growth. Some of the expected or planned new generation facilities were renewable energy projects, projects which were proposed to meet Wisconsin's Renewable Portfolio

[4] As is also noted in the introduction of this SEA, identification in the SEA of any application pending before the Commission or applications that the Commission anticipates receiving in the near future cannot be construed as any indication of the Commission's potential approval or denial of those applications.

Standard (RPS) requirement. Recent examples include WP&L's Bent Tree Wind Project (approved, 200 MW), WEPCO's Glacier Hills Wind Project (approved, 162 MW), and its Rothschild biomass facility (approved, 50 MW). Major build-out during 2002-2010 has now concluded, and no new generation is anticipated for the near term.

EMISSION CONTROL AND GENERATION FACILITY UPGRADES

Wisconsin generators continue to face the task of updating their current coal facilities to comply with federal emissions requirements. Table 5 indicates the current status of completed and expected major emission control projects at Wisconsin's power plants as of May 2012. The status of emission control projects at Columbia Units 1 and 2 has moved from "filed an application" in the previous SEA to "under construction" in the current SEA. In addition, the Edgewater Unit 5 selective catalytic reduction (SCR) project is underway. As shown on Table A-3 in Appendix A, MGE intends to retire Blount Units 3, 4, and 5 in 2013. Blount Units 6 and 7 are operated as natural gas only units as of April 2010.

Table 5: Major Emissions Control Projects* at Wisconsin Utilities' Power Plants

Unit Name	Utility Owner	Project Status	Type of Emission Control**	Year of Commercial Operation	Estimated Cost (in $million)
Pleasant Prairie 2	WE	Complete	SCR	1985	$72.5
Pleasant Prairie 1 & 2	WE	Complete	SCR/FGD	1981-1985	$291.4
Weston 3	WPSC	Complete	Baghouse	1982	$26.0
Oak Creek 5	WE	Under Construction	SCR/FGD	1959	$830.0
Oak Creek 6	WE	Under Construction	SCR/FGD	1961	Included in above
Oak Creek 7	WE	Under Construction	SCR/FGD	1965	Included in above
Oak Creek 8	WE	Under Construction	SCR/FGD	1967	Included in above
Edgewater 5	WPL	Under Construction	SCR	1985	$153.9
Columbia 1	WPL/ WPSC/ MGE	Under Construction	FGD	1975	$627.0
Columbia 2	WPL/ WPSC/ MGE	Under Construction	FGD	1978	Included in above
Nelson Dewey 1 &2	WPL	Application pending; Inactive	FGD	1959-1962	TBD
Weston 3	WPSC	Pending	FGD	1981	TBD
Edgewater 5	WPL	Anticipated	FGD	1985	TBD
				Total	$2,000.8

* Major emissions control projects only include projects over $25 million. Table does not include combustion control projects for NO_x, and does not include activated carbon control projects for mercury.
** Selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) are methods of chemically converting NO_x emissions into other substances. Flue gas desulfurization (FGD) refers to methods of chemically transforming SO_2 emissions into other substances. All are chemical methods of converting air pollutants to more benign and/or manageable substances.

In December 2005, the Nuclear Regulatory Commission (NRC) granted a license extension to Point Beach Nuclear Power Plant Units 1 and 2, which authorizes the Point Beach facility to operate until at least 2030. The Kewaunee Nuclear Power Plant was granted a license extension in February 2011, which authorizes it to operate until at least 2033.

Wisconsin currently has capacity beyond the minimum required planning reserve margin for several years. However, Wisconsin's generation fleet and the EPA's new rules (either recently proposed or those anticipated in the near future) may change Wisconsin's generation mix in the coming years. Decisions of retirement, mothballing, emission retrofits, or new generation are beginning to be addressed in the MISO footprint.

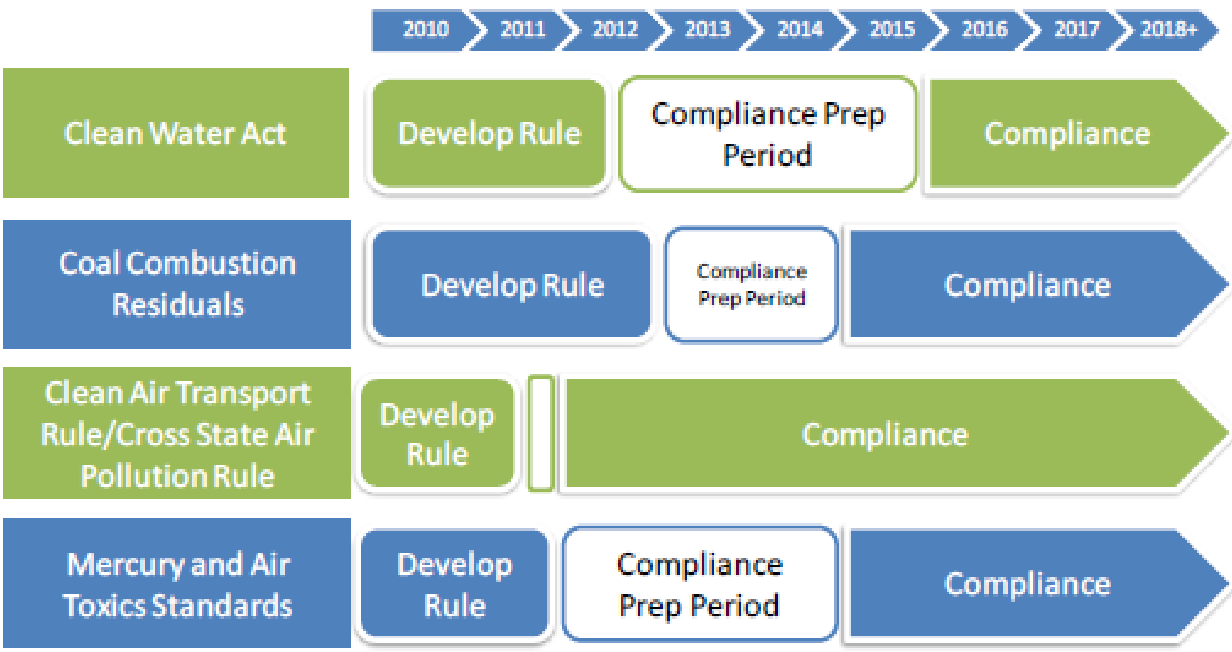
THE GENERATION PICTURE

Wisconsin has come through a cycle of building new generation capacity in order to adequately address past capacity limitations. Wisconsin utilities face a new challenge – having what appears to be additional capacity. This could, however, be impacted by any compliance plan to meet new EPA rules. Within this challenge lies a potential opportunity for Wisconsin, other states in the MISO regional energy market, and MISO itself to work together on a coordinated compliance plan that sets a reasonable timeline for meeting EPA requirements while minimizing customer costs. Since Wisconsin has been at the front edge of a construction cycle, newer units in Wisconsin have a benefit over generation located in other parts of the MISO footprint because they have environmental controls that likely will be in compliance with anticipated EPA requirements. Other states may not be as well positioned with their capacity mix in the near future, and Wisconsin utilities may increasingly serve as energy exporters if other states become capacity strapped in the next few years. Nonetheless, additional analysis is needed to identify realistic assumptions about the benefits that may flow to ratepayers from this capacity and energy. Furthermore, important changes to the transmission system and operation will likely be a prerequisite to Wisconsin selling any excess capacity or energy. For instance, some transmission infrastructure improvements in the Chicago and Northern Indiana area may be needed.

Wisconsin utilities still generate a strong majority of our state's daily electricity and any exports through base load coal generation facilities. Depending on the exact compliance rules implemented as part of EPA's environmental regulation, Wisconsin utilities will have to respond with new or retrofitted generation facilities that meet all the emission restrictions, or may be required to purchase emission allowances. During the next two years, coordinated plans will be developed in the MISO reliability footprint to meet the new EPA rules. A simple diagram of the various rules and timeframe for compliance is outlined in Figure 4.

EPA finalized a mercury and air toxics rule on December 16, 2011, that included provisions to provide some flexibility to utilities who do not expect to meet the three-year compliance deadline. The rule requires utilities to install scrubbers or other controlling devices that will remove 91 percent of mercury from coal. State permitting authorities (here, the Wisconsin Department of Natural Resources) have the option of allowing utilities an extra year to install emissions control equipment, and the EPA may issue an order allowing another additional year, extending the compliance time to five years total. MISO has estimated the region-wide cost at $33 billion.

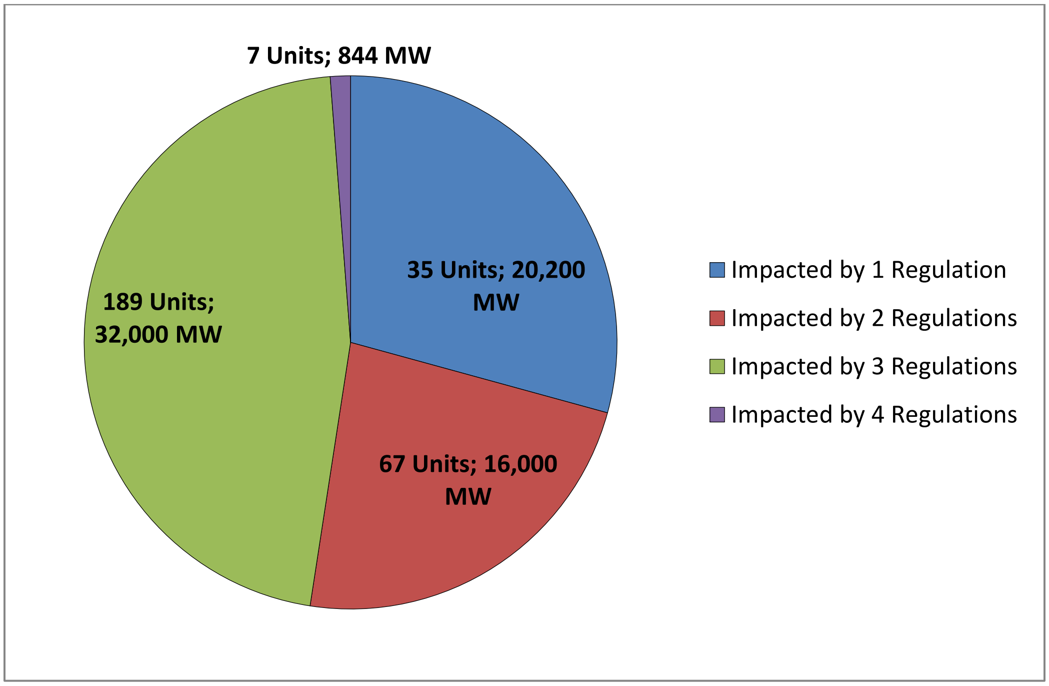
Figure 4: EPA Rules - Timeframe for Compliance



Source: www.midwestiso.org

There are approximately 70,000 MW of coal capacity in the MISO footprint. About 60,000 MW of that capacity will need to address the new EPA rules by 2015. The coordination of planned outages and obtaining access to the supply chain for design engineering, project management, equipment, and skilled labor will be a severe challenge. Some entities or generators are exploring options for compliance with the new EPA rules without causing reliability problems in the interim. Figure 5 below is an estimated breakdown by MISO of the rule impacts on these units.

Figure 5: The Number of Coal Units and MW in MISO Footprint Impacted by One or More EPA Regulations



Source: www.midwestiso.org; MTEP2011

TRANSMISSION SYSTEM PLANS, ISSUES, AND DEVELOPMENTS

Locations and Descriptions of Proposed Transmission Projects

By state statute, this SEA is required to report all transmission lines designed to operate at voltages above 100 kilovolts (kV) on which transmission providers propose to begin construction before 2018, subject to Commission approval. ATC, a stand-alone transmission company created in 2001, is the largest transmission provider in Wisconsin; data for this SEA was also provided by DPC and Xcel. "Construction" means building new lines, rebuilding existing lines, or upgrading existing lines.

Beyond new construction, the Commission oversees rebuilding or upgrading existing lines, which may also require new structures or new ROW. To rebuild a line means to modify or replace an existing line; in other words, to keep it at the same voltage and improve its capacity to carry power through new hardware or design. To upgrade an electric line means to modify or replace an existing line, but at a higher voltage. An upgrade also improves the line's capacity to carry power. Both rebuilding and upgrading may require some (or many) new, taller structures. New ROW may also be needed if the new structures require a wider ROW, or if the line route requires relocation to reduce environmental impacts. Either way, rebuilt or upgraded transmission lines usually need significantly less new ROW than new lines.

The primary reasons for needing additional transmission lines may include one or more of the following:

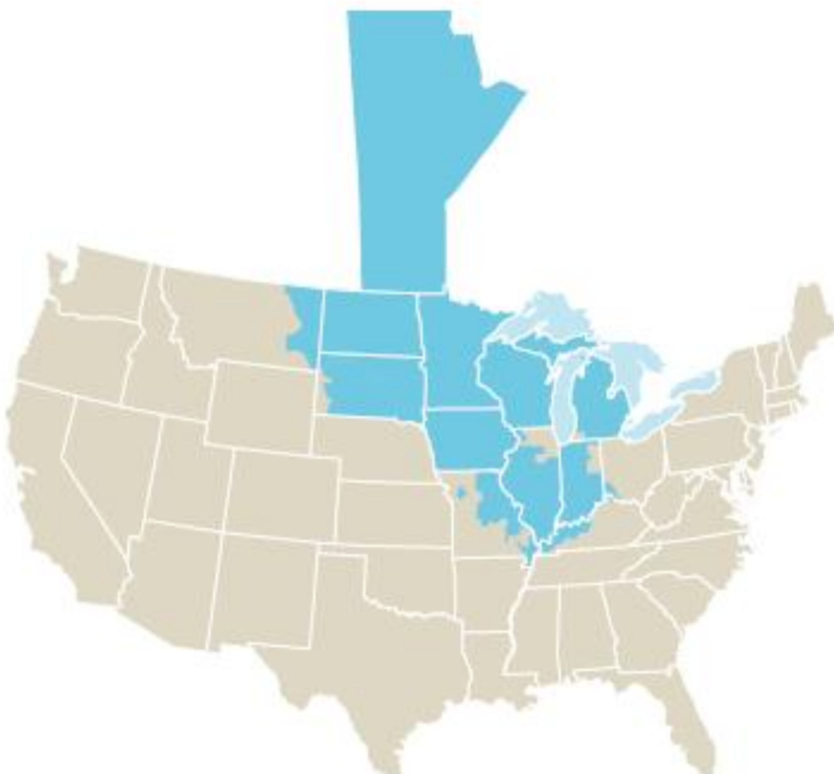
- Growth in an area's electricity use, which often requires new distribution substations and new lines to connect them to the existing transmission system, or needed increased capacity of existing transmission lines;
- Aging of existing facilities that has resulted in reduced reliability due to poor condition;
- Maintenance of system operational security for the loss of any one transmission or generation element;
- Increased power transfer capability or access;
- Increased access to support the expanded use of renewable energy;
- Generation interconnection agreements and transmission service requirements for proposed (or approved) new power plants; and
- Maintenance of transmission system reliability and performance.

In general, the higher a line's voltage, the more power it can carry and losses are reduced. As a consequence, the higher voltage transmission lines are important in delivering large amounts of power on a regional basis, and the lower voltage lines primarily deliver power over a more limited area. The ability to deliver power reliably to local substations and the ability to import power from, or export to, other regions are both important functions in providing adequate, reliable service to customers.
Table A-2 in Appendix A shows new electric transmission lines on which construction is expected to start by 2018 if approved by the Commission.

Transmission Planning in the Midwest

Transmission planning is becoming increasingly regional and inter-regional. Wisconsin belongs to Midwest Independent Transmission System Operator (MISO). Its reliability territory, displayed below in Figure 6, covers a large portion of the Midwest. Commissioners and Commission staff actively participate in several regional transmission planning initiatives that are summarized in the following pages.

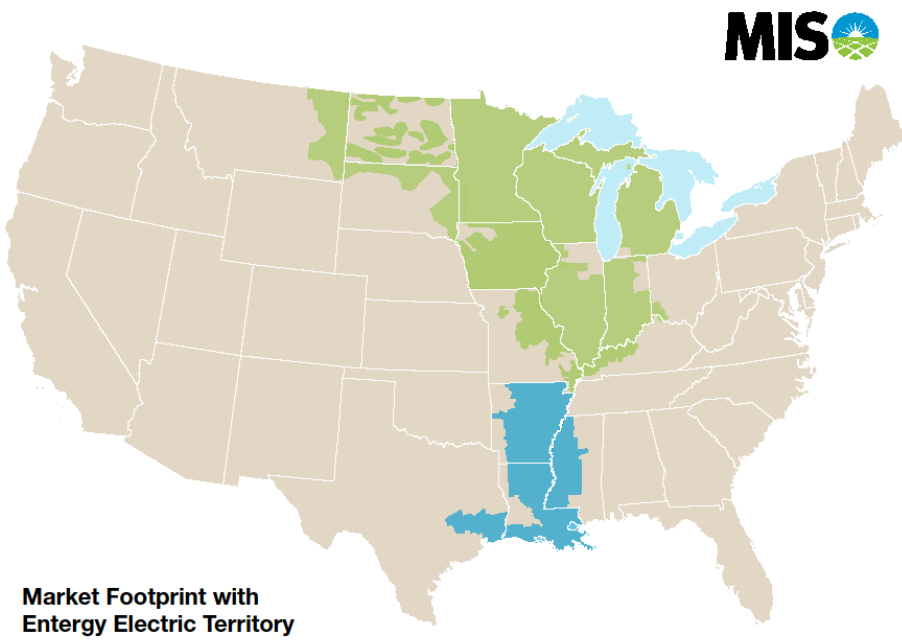
Figure 6: MISO Reliability Coordination Area



Source: www.midwestiso.org

One new development is the potential integration in the MISO footprint of Entergy utilities to the south. Entergy's territory includes portions of the states of: Arkansas, Mississippi, Louisiana, and Texas. Integration of Entergy utilities is being reviewed by each respective state, as well as existing states in the MISO footprint. If approved by all six Entergy states, and FERC, Entergy and its six utility operating companies would join MISO and integrate by the end of 2013. The addition of Entergy will add 15,000 miles of transmission and 30,000 megawatts of generation capacity into the MISO footprint. Figure 7 below shows the MISO market footprint with Entergy utilities included.

Figure 7: MISO Market Footprint with Entergy Electric Territory Included



Source: www.midwestiso.org

MISO TRANSMISSION PLANNING – OBJECTIVES AND SCOPE[5]

The MISO regional transmission planning process is an ongoing comprehensive expansion plan for both the reliability and economic needs of 11 states and one Canadian province. The five MISO planning principles are as follows:

- Make the benefits of a competitive energy market available to customers by providing access to the lowest possible energy costs;
- Provide a transmission infrastructure that safeguards local and regional reliability;
- Support state and federal renewable energy objectives by planning for access to all such resources (e.g. wind, biomass, demand-side management);
- Create a mechanism to ensure that investment implementation occurs in a timely manner; and
- Develop a transmission system scenario model and make it available to state and federal energy policy makers to provide context and information regarding potential policy choices.

[5] This section of this SEA relies significantly on documents produced and made available from MISO, and used under permission.

The MISO scope of operations includes approximately 142,930 MW of generation capacity in a reliability footprint with a peak load of approximately 110,032 MW. The MISO market consists of 131,010 MW of capacity and 103,975 MW peak load. The energy and operating reserves markets had gross annual charges of $27.5 billion in 2010. Wisconsin represents about 14.5 percent of the MISO system. Membership includes 35 transmission owners and 98 non transmission owners. The membership area covers 920,000 square miles with 49,641 miles of transmission lines ranging from 69 kV to 500 kV.

MISO WHOLESALE ENERGY AND DEMAND RESPONSE RESOURCES

The MISO wholesale energy market accepts load bids net of demand response from retail electricity providers and generation or price responsive demand offers from resource owners. MISO uses this information to establish the clearing price for the wholesale energy market. Clearing prices are set at various nodes and include an energy price, a congestion cost, and a loss component. These three items are utilized by MISO to centrally dispatch resources to match load in a manner that maintains electric system reliability and simultaneously sends price signals about where generation or transmission is needed or demand could be reduced. The Midwest Energy and Operating Reserve Market is used by 374 market participants. The market operates with a five-minute dispatch, 1,975 pricing nodes, and clears $27.5 billion annually in gross market charges. The dispatch reflects MISO's best attempt at least cost dispatch given all contingencies and system congestion.

The MISO energy and ancillary services market and resource adequacy structure provide several options for the participation of demand response resources. The most common demand response resources, direct load control programs for residential air conditioners and industrial and commercial interruptible load programs, receive credit as capacity resources under the provisions of the MISO resource adequacy program. Put another way, a demand response resource is a tool that can be used to reduce the forecasted peak load. Since capacity expansion is based largely on peak load requirements, demand response resources can have the effect of reducing the amount of generating resources that are needed to provide reliable electricity. Aside from this long-term benefit, demand response programs can also participate in MISO's daily energy market as "price sensitive loads." These programs can be called upon to reduce loads when price spikes occur in the energy market, thus helping to diminish high energy prices and reduce utility expenses.

MISO also allows utilities to nominate loads or customer-owned generation resources that are not designated as capacity resources under the resource adequacy structure to participate as "emergency demand response" resources which would be called on only during system emergencies or for short-term high price volatility. This program increases system reliability and provides customers an opportunity to receive compensation for voluntarily reducing loads or operating generation during system emergencies or sustained price spikes to reduce the need for forced local or regional blackouts.

TRANSMISSION PLANNING EFFORTS IMPACTING WISCONSIN

There are a number of transmission expansion planning efforts that may have an impact on Wisconsin. One of the broadest of these planning efforts is funded by a U.S. Department of Energy (DOE) grant; the Eastern Interconnection States' Planning Council (EISPC). EISPC consists of a group of state officials who are engaged in a planning effort for the eastern U.S. EISPC is comprised of the 39 States in the Eastern Electric Transmission Interconnection plus the District of Columbia, the City of New Orleans, as well as eight Canadian Provinces.

The Eastern Interconnection Planning Collaborative (EIPC) is an effort being developed and led by 26 planning authorities from the U.S. and Canada to conduct transmission analyses at the interconnection level. EISPC is the regulator side to the EIPC process, and holds seats on EIPCs' Stakeholder Steering Committee. EIPC and EISPC are not developing a specific transmission plan that will be implemented.[6] Rather, they are studying a number of scenarios for a variety of potential futures.

In addition to more comprehensive regional studies, MISO has produced targeted studies to address specific issues such as: congestion, narrowly congested areas, narrowly constrained areas, RPS in the Midwest, and queue related and operational studies. Almost simultaneously, a multiple regional effort known at the Eastern Wind Integration and Transmission Study (EWITS) was completed in 2010. It was started by MISO but included many of the regional transmission organizations (RTO), independent system operators and other large planning organization in the Eastern Interconnection. They too looked at how to manage the energy markets on the future with different amounts of renewable energy and transmission resources.

At a sub-regional level, the Organization of MISO States (OMS) is engaged in planning efforts in MISO. OMS is a non-profit, self-governing organization of representatives from each state with regulatory jurisdiction over entities participating in MISO. The purpose of OMS is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, the Federal Energy Regulatory Commission (FERC), other relevant government entities, and state commissions as appropriate.

While any individual proposal will have to go through the transmission planning process at MISO and gain approval from regulatory agencies, the Commission will continue following and be involved with individual proposals that could impact Wisconsin energy delivery and pricing. Some additional regional transmission planning efforts are further described below.

MISO TRANSMISSION EXPANSION PLAN (MTEP)

The MTEP process provides an annual report which identifies a number of transmission projects that are being planned or alternatives being considered. The planning effort is a collaboration of MISO's planning staff

[6] Additional information can be found at www.eipconline.com.

and its many stakeholders, including utilities and independent power producers throughout the footprint. The planning process is conducted at many different levels, including special task forces, work groups, sub-committees, and, finally, the Advisory Committee.[7] The process increased the frequency of updates for project approval to every six months if necessary to proceed with construction for in service date deadlines.

As part of the MTEP process, proposed utility transmission projects are first classified as conceptual and are called Appendix C projects. As the proposed project moves to the construction application phase at the respective state Commission, the project is moved to what is called Appendix B, meaning in construction and planning process. As part of its core mission, the MISO Board of Directors in every MTEP determines if such new transmission projects in Appendix B are deemed appropriate for cost sharing among MISO stakeholders. If the MISO Board makes such a finding, the transmission project in question is deemed to move out of Appendix B treatment to what is called an Appendix A classification, to indicate that the project's costs will be shared. In no way in any of the Appendix classifications does the MISO Board actually approve the construction of a project. MISO in MTEP only determines if the project will work with its system, and under federal tariff, whether the projects costs can be shared as outlined above. Actual project construction, siting and need determination remains a state public utility commission function.

In December 2011, MISO approved the MTEP11 cycle report. MTEP11 contains 215 new projects that represent an incremental $6.5 billion in transmission infrastructure investment within the MISO footprint and fall into the following four categories:

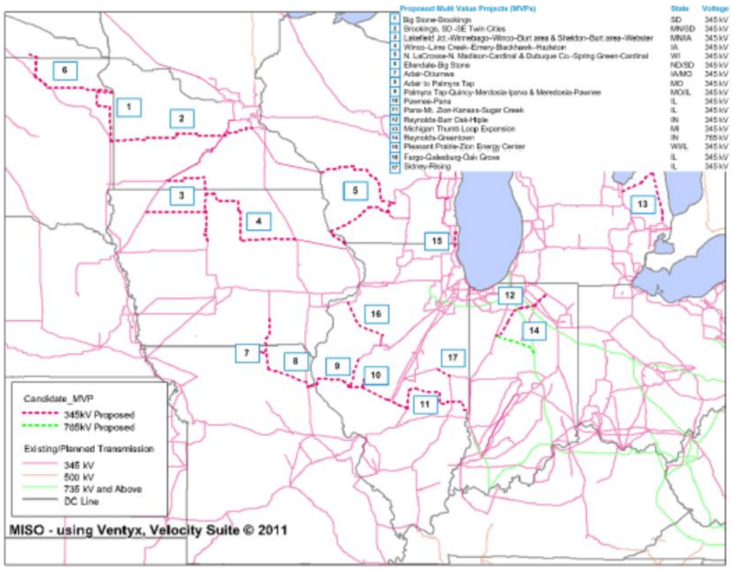
- Multi Value Projects (MVP) – projects providing regional public policy, reliability, and/or economic benefits – 16 projects, $5.1 billion;[8]
- Baseline Reliability Projects – projects required to meet North American Electric Reliability Corporation (NERC) reliability standards – 40 projects, $424 million;
- Generator Interconnection Projects – projects required to reliably connect new generation to the transmission grid – 26 projects, $273 million; and
- Other projects – wide range of projects, such as those designed to provide local economic benefit but not meeting the threshold requirements for qualification as Market Efficiency Project (MEP), and projects required to support the lower voltage transmission system – 133 projects, $681 million.

This is the first year the MVP category was used. Three of the MVPs approved in MTEP11 are at least partially located in Wisconsin, including lines from La Crosse to Madison, from Madison to Dubuque, and from Pleasant Prairie to Zion, Illinois. A graphic of MISO approved MVP projects is shown below in Figure 8.

[7] The Advisory Committee is a forum for its members to be apprised of MISO's activities and to provide information and advice to the management and Board of Directors of MISO on policy matters of concern to the Advisory Committee, or its constituent stakeholder groups, but neither the Advisory Committee nor any of its constituent groups shall exercise control over the Board or MISO.

[8] MVPs are paid for under federal tariff by all load in the MISO footprint. This means MVPs in Wisconsin do not cost ratepayers in the state the full cost. However, the flipside is also true in that Wisconsin ratepayers will pay for MVPs in other states.

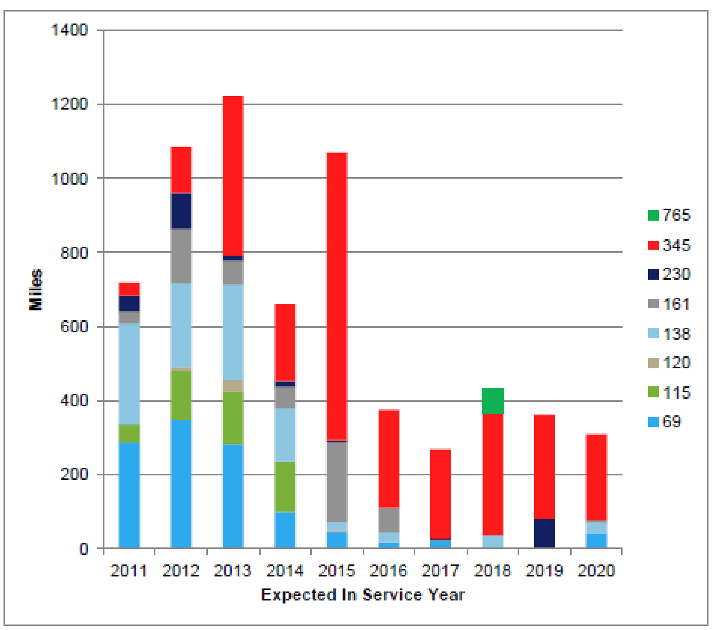
Figure 8: Map of MISO Approved Multi Value Projects



Source: www.midwestiso.org

The majority of approved projects are categorized as baseline reliability projects, generation interconnection projects, or "other" projects. Figure 9 shows a total of approximately 3,695 miles of new and 2,965 miles of upgraded lines in the 2011-2021 time period.

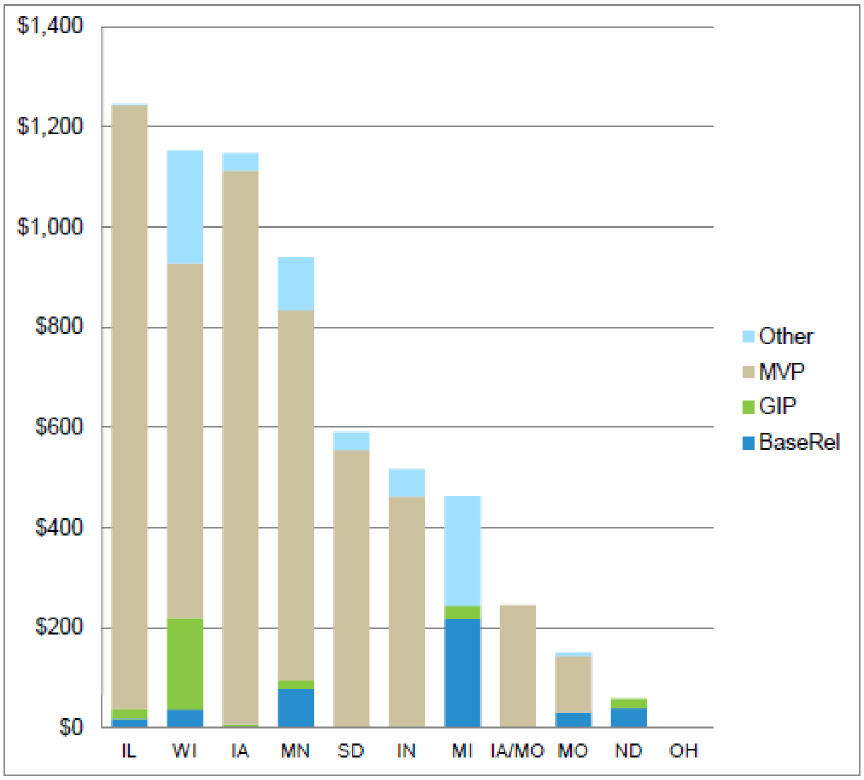
Figure 9: MISO Transmission Voltage, Mileage, and Expected In Service Date



Source: www.midwestiso.org

Figure 10 below shows how the approved project types in MTEP 11 are shared among the MISO states.

Figure 10: MISO Approved Projects by $Million, Type and State



Source: www.midwestiso.org

In addition to projects approved by the MISO board, the MTEP planning process further includes projects which are still in a planning process or under MISO review, and projects which are in the early planning stages and have not been yet reviewed for effectiveness.[9]

AMERICAN TRANSMISSION COMPANY (ATC)

ATC is a for-profit transmission utility. ATC's transmission service rates are subject to the jurisdiction of FERC. Construction approval, siting of new transmission, and new project cost scrutiny are regulated by the Commission and by the Michigan Public Service Commission for the Upper Peninsula. Due to changes in law granting open access to the transmission system for all users, transmission planning has increasingly been taking on a regional character. ATC has been part of numerous collaborative planning processes in the Midwest, and the Commission plays an active role in monitoring ATC's activities to protect the public interest.

[9] For more information on the MTEP planning process, the complete 2011 report can be found on the MISO website: http://www.midwestiso.org.

ATC annually produces a 10-Year Transmission System Assessment based on engineering studies of Wisconsin and the surrounding transmission system, looking for potential problems that may affect the future performance of the system. ATC's studies identify future projects needed to improve the adequacy and reliability of the electric transmission system. The major projects that ATC is planning for construction are listed in the appendix of this report.

In developing its annual 10-year transmission plans,[10] ATC considers many factors, including: (1) load growth; (2) new generation; (3) population trends; (4) electric reliability of the present grid; (5) the amount of congestion on the transmission grid; (6) pricing outcomes from MISO's operation of the wholesale energy markets; (7) project economics; (8) age of assets; (9) siting, including the impact on the environment and communities involved; (10) expected changes in the transmission grid around Wisconsin; and (11) state and federal policy.

ATC operates the present and future transmission grid according to enforceable electrical standards set by NERC and approved by FERC in 2007, as well as FERC Order 890. In performing its planning function, ATC takes input from all types of stakeholders, such as the public, utilities, communities, and MISO. ATC conducts its studies with review and oversight provided by MISO, FERC, NERC, and the Commission. Among utilities nationally, FERC has recognized ATC as one of the utilities with the best public planning practices.[11]

RECENTLY PROPOSED RELIABILITY PROJECTS[12]

Several recently announced reliability projects have direct implications in or near Wisconsin. These include:

- ATC: P3679 – 345 kV line from Outagamie County to Marquette County and 138 kV line from Menominee County to Delta County in the Upper Peninsula to support the integration of the new lines into the network
  - Expected In Service Date: 2014
  - Estimated Cost: $442 million
  - System Need: Reliability

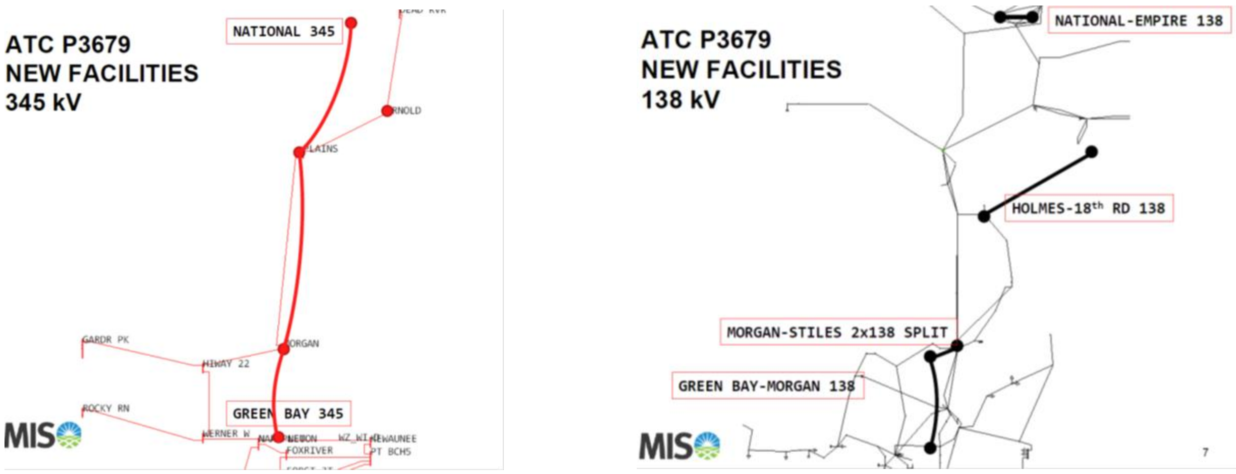
- ATC: Marathon County Wisconsin-Marquette County Michigan Project – 345 kV from central Wisconsin to the Upper Peninsula to update ATC Northern Plan; also calls for 115 kV rebuilds and 345/115 kV transformers
  - Expected In Service Date: 2017

[10] **ATC – *2011 10-Year Transmission System Assessment Summary Report***; http://www.atc10yearplan.com.
[11] FERC, Order 890.
[12] This information was obtained from MISO's sub-regional planning meetings after the original data filing request had been completed. As of March 2012, ATC may move forward with one of these projects out-of-cycle.

- Estimated Cost: Approximately $400 million (planning level)
- System Need: Reliability

A diagram of the two proposed ATC recent reliability projects are shown below in Figure 11.

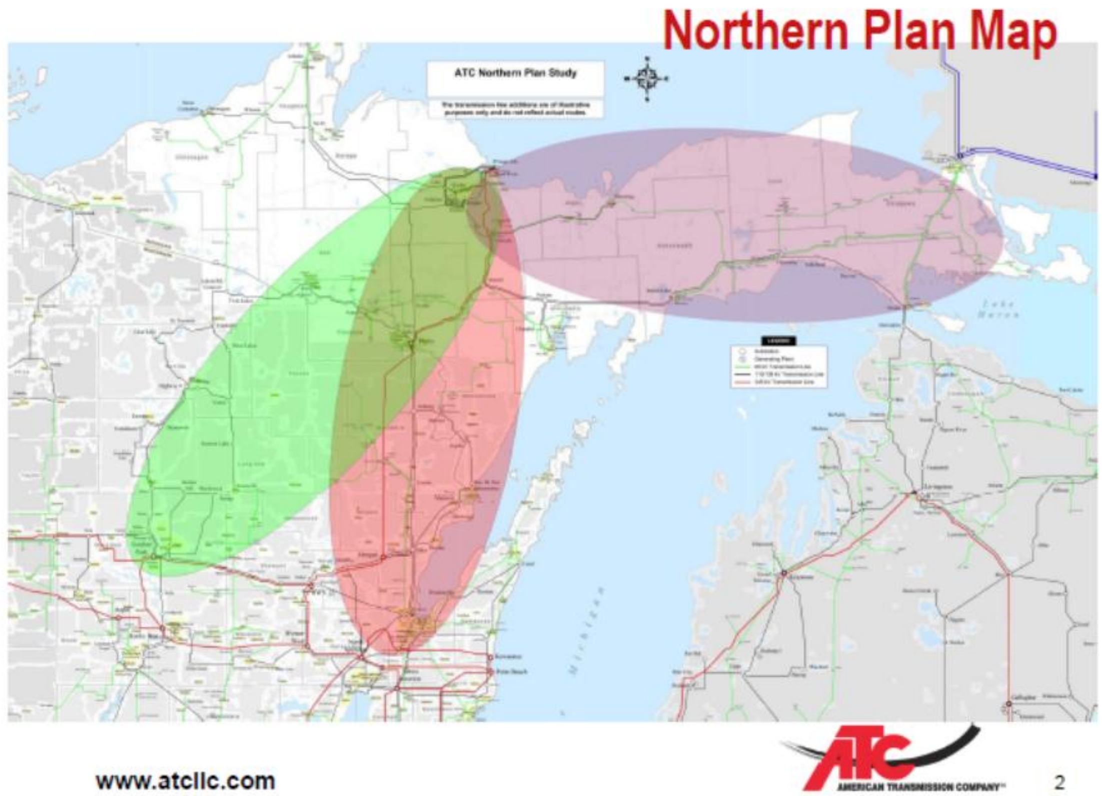
Figure 11: Proposed Northern Wisconsin ATC Projects (Green Bay North to the Upper Peninsula Border)



Source: www.midwestiso.org

ATC has identified a Northern Plan, which involves some preliminary projects that coordinate with existing northeast Wisconsin and Upper Peninsula projects to address generation changes, load changes, and developing transmission contingency concerns. ATC's Northern Plan area is depicted below in Figure 12.

Figure 12: ATC Northern Plan Map



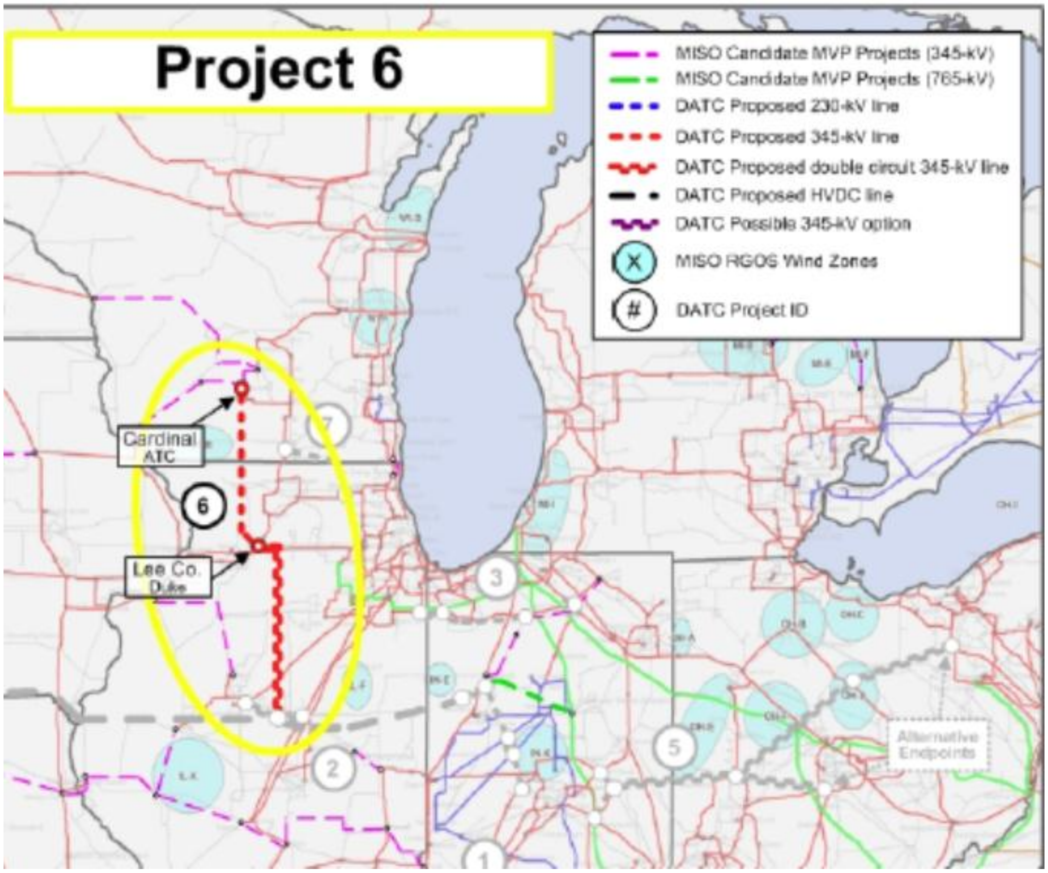
Source: www.atcllc.com

Duke Energy and ATC have formed a joint venture LLC organization (DATC) and are proposing Extra High Voltage (EHV), Alternating Current (AC), and High Voltage Direct Current (DC) in the West and Midwest. DATC presented two projects in the Wisconsin area at the December 2011 Sub-regional Planning Meeting. The projects from this joint venture may facilitate greater exchange of energy with the potential for ratepayer cost savings and may represent an expansion of the ATC business model, as ATC appears to want to grow as a company.

- DATC P3675 – 345 kV line from Cardinal, Wisconsin to Lee County, Illinois
    - ➢ Expected In Service Date: 12/31/2021
    - ➢ Estimated Cost: $184.5 million
    - ➢ System Need: Reliability, economics and renewable delivery

Below is Figure 13 that shows the approximate line location.

Figure 13: DATC P3675 – 345 kV Cardinal, Wisconsin to Lee County, Illinois



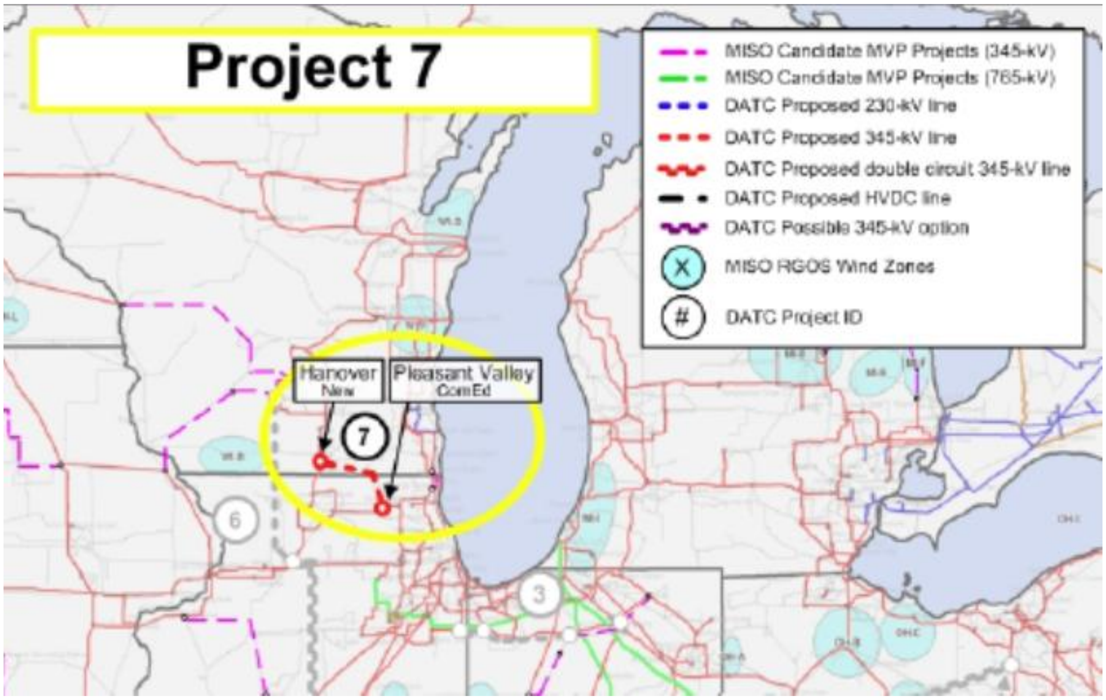
Source: www.atcllc.com

The other DATC project is listed as P3677 and is a 345 kV line from Hanover, Wisconsin to Pleasant Valley, Illinois.

- DATC P3677 – 345 kV line from Hanover, Wisconsin to Pleasant Valley, Illinois
  - Expected In Service Date: 12/31/2016
  - Estimated Cost: $128.8 million
  - System Need: Reliability, economics and renewable delivery

Figure 14 below shows a map depicting the approximate transmission routing.

Figure 14: DATC P3677 345 kV Hanover, Wisconsin to Pleasant Valley, Illinois



Source: www.atcllc.com

OTHER MAJOR TRANSMISSION OWNERS IN THE STATE

Xcel and DPC are the two other major transmission owners and operators in Wisconsin. These two transmission owners also follow mandatory NERC design standards and operating rules. As with ATC, Xcel's and DPC's projects in Wisconsin are reviewed by the Commission for need, design, routing, and environmental impact. Depending on the size of the project, each large project will follow the Certificate of Authority (CA) or the Certificate of Public Convenience and Necessity (CPCN).

Xcel produces an integrated long range plan for Minnesota. Both Xcel and DPC participated in the CapX2020 transmission plan with several other upper Midwest utilities. The plan sets out a number of projects that are primarily centered in Minnesota but also include North Dakota, South Dakota, and Wisconsin.

FEDERAL ENERGY REGULATORY COMMISSION (FERC) ORDER 1000

FERC issued Order 1000 on July 21, 2011, to reform FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. MISO believes it is mostly compliant with FERC Order 1000 but needs to expand documentation of some processes. States are invited to more fully participate in the process, but the exact nature of how that is to be accomplished in each RTO is yet to be determined. The MISO states via OMS are working on this initiative in 2012. More will be known for the final SEA.

FERC Order 1000 specifically requires:

- Public utility transmission providers participate in a regional transmission planning process to produce regional plans;
- Local and regional transmission planning processes consider state and federal public policy requirements; and
- Public utility transmission providers coordinate with neighboring regions to determine whether more efficient or cost-effective solutions are available for their needs.

FERC Order 1000 establishes cost allocation principles for regional and interregional transmission facilities. The allocated costs should generally be commensurate with established benefits. Different types of transmission facilities can have different allocation methods. One other key item that is being discussed and reviewed extensively is the removal of federal rights of first refusal from FERC approved tariffs and agreements; the theory behind this is that it will promote competition.

MARKET ANALYSIS AND PLANNING RESERVE MARGIN FORECASTS

This section provides an assessment of Wisconsin's electric industry as it addresses four of the topics mandated by law. Wisconsin Stat. § 196.491(2)(a) specifically requires the SEA to assess: (1) the extent to which the regional bulk power market is contributing to the adequacy and reliability of the state's electrical supply; (2) the adequacy and reliability of purchased generation capacity and energy to serve the needs of the public; (3) the extent to which effective competition is contributing to a reliable, low cost, and environmentally sound source of electricity for the public; and (4) whether sufficient electric capacity and energy will be available to the public at a reasonable price. The following sections address these concerns. The analysis incorporates data submitted by the electricity providers for the SEA and other data collected by Commission staff.

Extent to which Regional Bulk Power Market Contributes to Adequacy and Reliability of Wisconsin's Electric Supply

Adequacy and reliability are expected to remain robust with an acceptable planning reserve margin forecast through 2018. This assumes that retirements associated with the implementation of various EPA air and water quality rules do not force dramatic fossil fuel plant closings in Wisconsin. Data in this SEA show that planning reserves are expected to be above the 16-20 percent range for the foreseeable future.

The Commission currently requires that each electricity provider match loss of load expectation reliability criteria, as well as the planning reserve measurement process under Module E of MISO's transmission tariff, for the year ahead. For years 2-7 in this SEA's period, 2014-2018, electricity providers are to maintain a 14.5 percent planning reserve margin. Planning reserve margins in later years are often finalized through capacity purchases made a short time ahead of any shortfall.

Planning reserve data filed in this SEA actually shows that Wisconsin is experiencing somewhat of a surplus, with expected planning reserve margins exceeding the 14.5 percent threshold. The generally high reserve margins can be linked to a strong construction program from 2000 to 2010, which put upward pressure on electricity rates, but selling of any excess reserves can also increase the opportunity for energy sales into the MISO market. Under the fuel rules which govern electricity providers, such opportunity sales can benefit ratepayers because they would generate revenue that can be used to lower any needed increases in rates. Consequently, this result is not a typical pattern, and it simply reflects the lumpy nature of generation construction where one needs to build more supply ahead of load or demand.

Sufficient capacity is only part of the equation. Getting power from the generation source to customers is the other part. The current state of Wisconsin's transmission system was addressed in the previous section of this SEA, and it showed that the transmission system is able to deliver capacity and energy to customers without unusually large amounts of congestion or electricity losses. Commission staff estimates, using MISO wholesale energy market data, that net congestion costs have been minimal to the group of Wisconsin load serving entities. Some years have actually shown net revenues larger than $15 million. With respect to system energy losses on the transmission grid, Commission staff estimates a magnitude of $20 to $30 million,[13] which is comparatively small to the extent of the broad wholesale electricity market.

Adequacy and Reliability of Purchased Generation Capacity and Energy to Serve Public Needs

Generation capacity and energy may be purchased from facilities located within or outside of Wisconsin. Given the current surplus in Wisconsin's generating capacity, it is unlikely that new purchased power agreements will be required in the near future. Data in this SEA indicate that for the period 2013-2015, Wisconsin is a negative net purchaser – selling 215 MW at maximum. Furthermore, purchases from merchant facilities and independent power producers are expected to diminish from about 3,500 MW today to approximately 1,800 MW in 2018. Therefore, an adequate and reliable supply of purchased generation and energy to serve the public's needs is likely. Due to compliance with RPS, purchases of renewable energy via purchase power agreements may still be required.

Extent to which Effective Competition[14] Contributes to a Reliable, Low Cost, and Environmentally Sound Electricity Source

The issue of reliability has been addressed in previous sections of this report. This section focuses on low cost and environmentally sound requirements of Wisconsin statutes. The MISO wholesale energy market sets day ahead and real time prices for energy on a location-by-location basis throughout the area served by MISO participants. All Wisconsin utilities are part of the MISO.

Figures 15 and 16 show the on-peak Locational Marginal Pricing (LMP) from January 1, 2008, through December 31, 2010, for two pairs of MISO price points – an Illinois hub price compared to load node price WEC.S, and a Minnesota hub price compared to load node price WPS.WPSM. WEC.S is the price node for the southern Wisconsin load of WEPCO, and is representative of LMPs for southern Wisconsin. WPS.WPSM is the price node for the Wisconsin load served by WPSC, and is representative of LMPs for northern Wisconsin. The Minnesota and Illinois hub prices look at prices to the west and south of Wisconsin, respectively. The west and south are the two primary paths of imported or exported energy for Wisconsin. Because the energy charge component of the LMP is uniform throughout MISO, differing LMP prices are caused by congestion

[13] Commission staff estimate based on data compiled from MISO reports.

[14] Wis. Stat. § 196.491(2)(a)12 does not specifically identify what "effective competition" means. Since Wisconsin does not have retail competition, the Commission considers the impacts of the wholesale energy market operated by MISO. This does not indicate that the Commission believes that all markets operated by MISO provide "effective competition."

and/or loss charges. As was indicated in prior SEAs, as new transmission and generation came online, many congestion and loss issues have been relieved.

Figure 15: Average Hourly Day Ahead LMP for WEC.S and Ill.Hub[15]

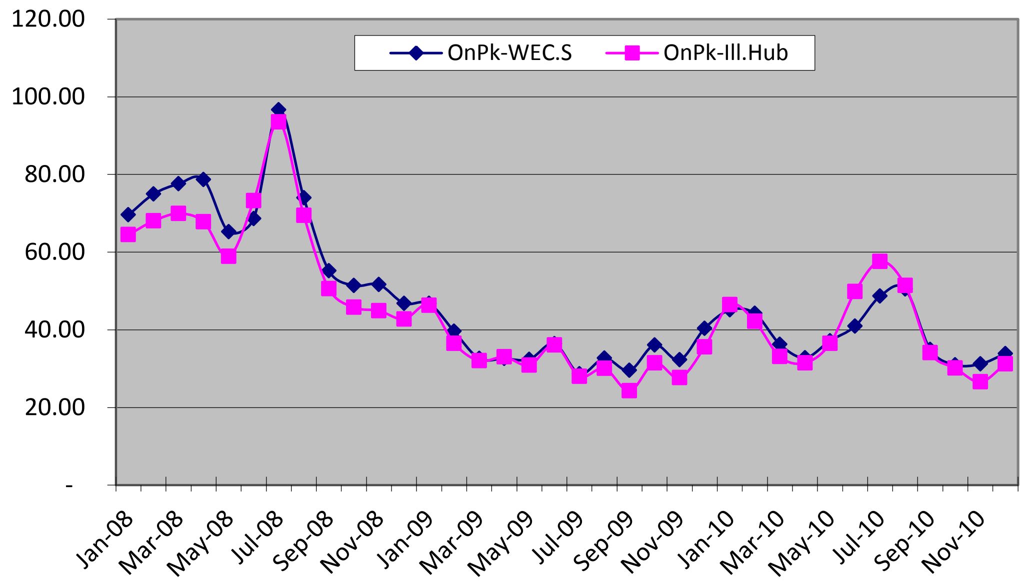
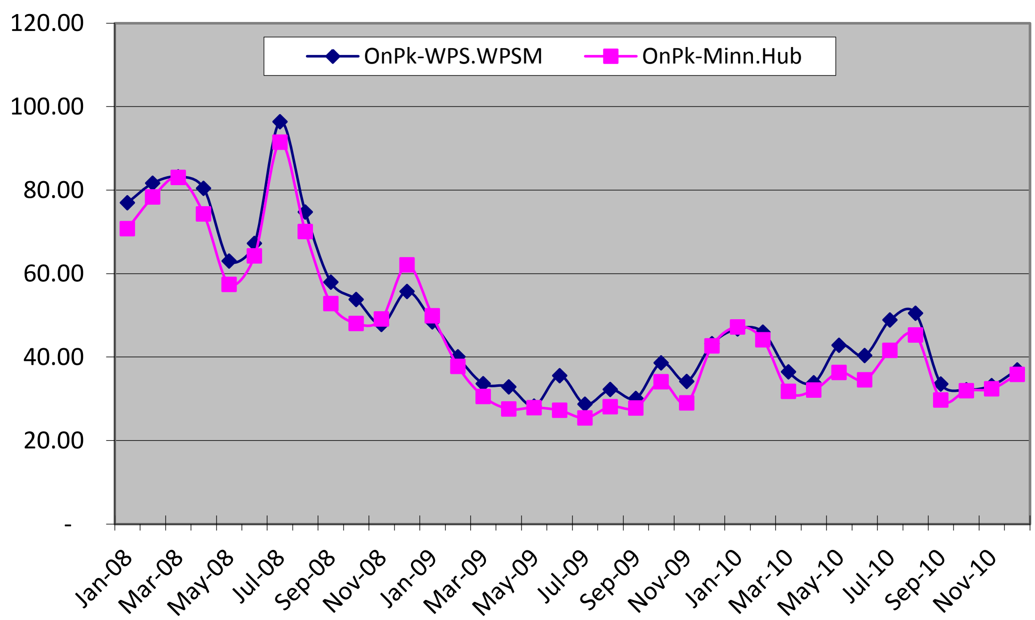


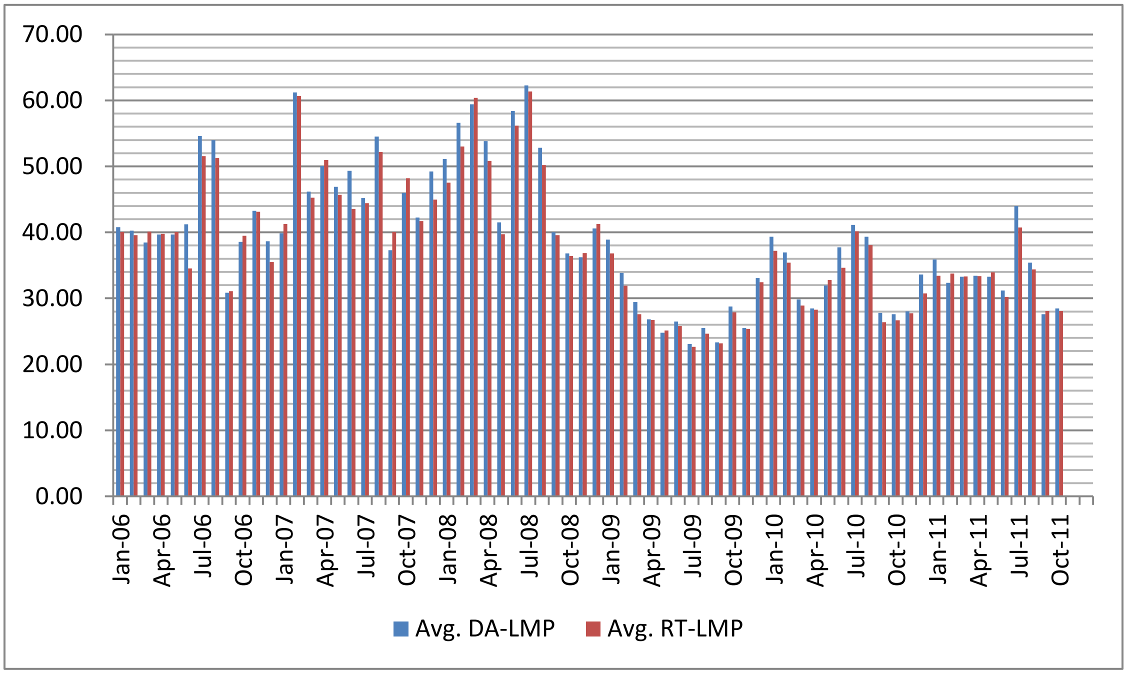
Figure 16: Average Hourly Day Ahead LMP for WPS.WPSM and Minn.Hub[15]



[15] Source: Commission staff, using data from MISO portal.

For a broader view of the complete MISO wholesale energy market, Figure 17 displays wholesale energy market prices in MISO since the start of the first full year of the market beginning in 2006.

Figure 17: MISO System-Wide Average Monthly Day-Ahead and Real-Time LMPs[15]



The charts above show close correspondence and correlation of energy market prices in Wisconsin to points outside the state. This is an indicator that the energy market has experienced price convergence, one sign that the markets were effectively competitive. To support that conclusion, a report by MISO's independent market monitor (IMM), entitled "State of the Market 2010" and published in June 2011, provides additional evidence. IMM's report concluded that MISO's wholesale energy markets were competitive with market clearing prices less than two percent higher than IMM's estimated reference-level marginal costs. IMM also concluded that the marketplace experienced only minor output withholding which could effectuate non-competitive prices.[16] This demonstrates that the MISO markets and Wisconsin entities' participation in such markets are properly bounded by effective competition.

[16] In the IMM 2010 State of the Market report, Dr. David Patton (on page ii of the Executive Summary) stated to stakeholders and the Federal Energy Regulatory Commission, "Overall, we found that markets operated by MISO performed competitively in 2010. Although certain suppliers in MISO have local market power, our analysis suggests very few competitive concerns that suppliers withheld resources to raise prices…Because the market continued to perform competitively in 2010, market power mitigation measures were employed infrequently to address withholding that would have increased energy prices or uplift costs."
http://www.potomaceconomics.com/uploads/midwest_reports/2010_State_of_the_Market_Report_Final.pdf

The final topic in this section is an assessment of whether competitive markets are contributing to an environmentally sound source of electricity for the public. According to conventional economic theory, competitive markets will consider all direct economic costs and any indirect costs associated with externalities, such as pollutants, that have been regulated or monetized. In cases where legitimate externalities have not been factored in, any non-private costs associated with such externalities are ignored. There may be some exceptions where the public may be willing to pay a premium for goods or services that are perceived to be environmentally superior.

The EPA has promulgated and proposed rules that regulate utility emissions of a number of pollutants such as sulfur dioxide (SO2), nitrogen oxide (NOX), particulate matter and mercury. Compliance costs are incurred by all MISO market participants who are obligated to comply with these EPA rules. The MISO market takes into account these direct economic costs thereby contributing to environmentally sound sources of electricity for the public.

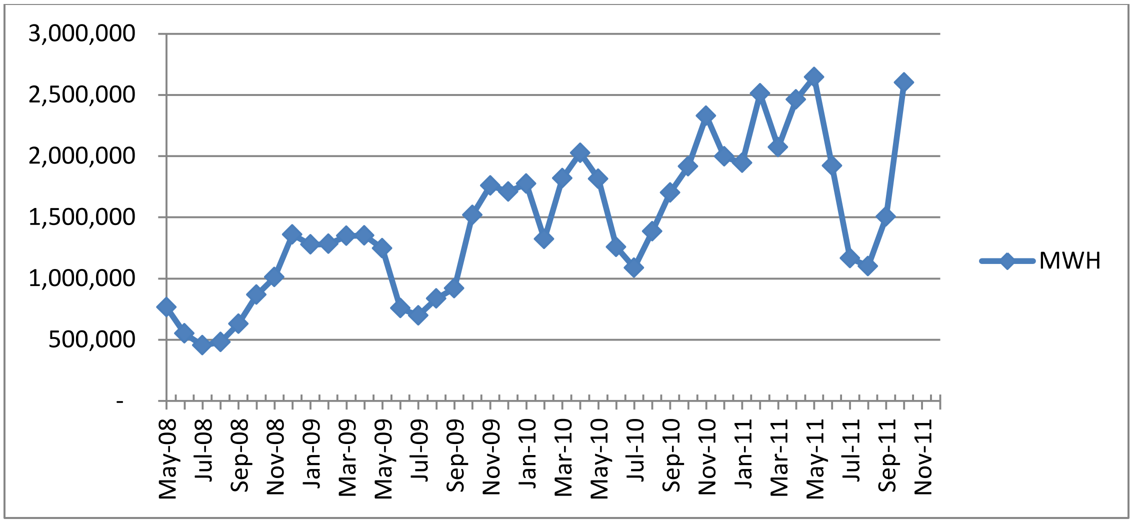
Assessment of Whether Sufficient Electric Capacity and Energy will be Available to the Public at a Reasonable Price

As noted in Table 1, planning reserve margins are projected to be at least 13.6 percent through 2018. The magnitude and the mix of new electric generation appear to answer the statutory concern about sufficient capacity in the affirmative. Wisconsin's electric generation supply future appears in strong shape.

In regard to the finding on reasonable price, the Commission reviews all purchase power contracts either during the formal rate case process or if asked to rule on them before implementation, such as during a construction case. As for units that are constructed, the Commission reviews and makes sure that costs associated with generation that will be rate-based pass an appropriate cost effectiveness threshold. The prior section noted the competitiveness of pricing in wholesale energy markets operated by MISO. For these reasons, the Commission concludes that capacity and energy will be available at a reasonable price.

The state has implemented an RPS that requires 10 percent of energy must come from defined renewable energy resources. This requirement affects Wisconsin's optimal energy expansion path. Wind energy has accounted for most of the utilities' renewable energy and recent and future construction activity. Wind energy has low marginal costs of generation, but it has intermittent availability. The varying availability of wind energy can be complemented by pumped storage as well as rapidly available alternative generation capacity, such as natural gas-fired combustion turbines and combined-cycle units. This may imply higher capacity utilization for these units. These features would add to the cost of the wind project, and so far none of these methods is used in Wisconsin. Although there are limitations created with variable generation in planning efforts, it is possible to mitigate some of the variation. Figure 18 below displays the growing importance of wind energy in the MISO footprint as well its variability due to changes in weather.

Figure 18: Monthly Wind Generation in MISO



Source: www.midwestiso.org

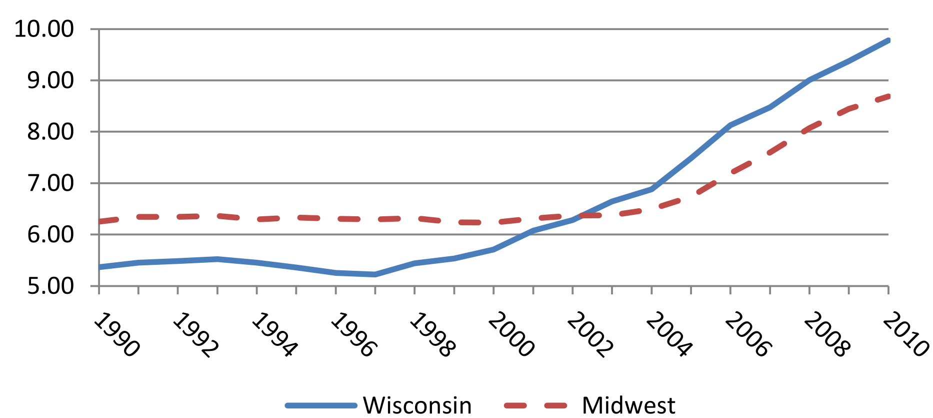
Due to the strong construction program of 2000-2010 and decreased energy consumption and growth in peak demand because of the recent recession, such developments have tempered the need for new capacity. The Commission will continue to carefully weigh the need for new capacity, as well as the optimal generation mix, as we move forward. By law, the Commission must also ensure that Wisconsin utilities comply with the state RPS in a cost effective manner.

RATES

Direct rate comparisons among states and regions are increasingly difficult to make due to the complexities of energy regulation and the energy market in general. Rates can vary widely based on factors such as whether a state is in a construction cycle with generating facilities or expanding its transmission infrastructure. Rates are also influenced by various regulatory rate structures utilized in the Midwest. Wisconsin has several vertically integrated utilities with regulated retail rates and a stand-alone transmission company, while other states, such as Illinois, use a deregulated retail rate structure. How a state and its utilities handle the accounting behind the rate setting process – for example, if cost deferrals are being approved – can affect the timing of rate impacts. The treatment of fuel costs can also vary from state to state, and federal policy and regulations can have an effect on rates as well.

Wisconsin remains ahead of many other states with respect to its investment in new electric generation and transmission facilities needed to address future service reliability, and it is well positioned in the near future to meet its energy demand needs. Wisconsin entered the construction cycle earlier than other states in the Midwest partly because its economy was stronger than in surrounding states. This required generation plants to be constructed in the late 1990s and early 2000s for which utilities now need to obtain cost recovery. These new cost competitive plants will be positioned to potentially sell any additional energy into the wholesale market benefitting retail customers, because such revenues are directly credited to a utility's expected revenue requirement during a rate proceeding, reducing the amount of money to be collected from ratepayers. As noted in Figure 19, this construction cycle has had rate impacts on customers in Wisconsin. To ensure that Wisconsin ratepayers benefit from this additional capacity, the Commission will continue to evaluate and promote the potential for selling energy into the MISO market. Selling excess energy or capacity is returned dollar for dollar to retail customers in the Commission's rate setting process.

Figure 19: Average Rates in Wisconsin and the Midwest[17] 1990-2010



Source: U.S. Department of Energy, Energy Information Agency

[17] As defined by the U.S. Census Bureau; includes Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota and Wisconsin.

Recently promulgated and proposed federal environmental regulations, such as the EPA Cross State Air Pollution Rule (CSAPR) and Utility Maximum Achievable Control Technology (MACT) Rule, will likely increase the operating costs of Wisconsin utilities. MISO projects 12.6 gigawatts (GW) of coal units (MISO estimate as of 3/9/2012) in the MISO footprint will be retired in 2014-2015. The exact magnitude and timing of these costs, and the degree to which they will affect Wisconsin (and other states as well) retail rates is highly uncertain. It is also unclear what these rate impacts might be relative to other states, but MISO estimates that the retirement of 12.6 GW would erode MISO projected reserve margins, causing them to drop system resources 6 to 7 percentage points below required targets. MISO also estimates that $33.0 billion will be needed to retrofit and/or replace units, and this would lead to energy prices potentially increasing by $5/MWh. The Commission will continue to monitor this evolving situation.

According to the U.S. Energy Information Administration's (EIA) reported 2010 sales and revenue information in its Electric Power Monthly – January 2011 report, the U.S. average rates in the residential, commercial, and industrial classes all increased in the past year. The trend in Wisconsin rates generally matched its surrounding environment. Tables 6, 7, and 8 summarize average rates for residential, commercial, and industrial rates in the Midwest and the country.

Table 6: Residential Average Rates in the Midwest and U.S. (in cents)[18]

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Illinois	8.39	8.38	8.37	8.34	8.42	10.12	11.07	11.27	11.52
Indiana	6.91	7.04	7.30	7.50	8.22	8.26	8.87	9.50	9.56
Iowa	8.35	8.57	8.96	9.27	9.63	9.45	9.49	9.99	10.42
Michigan	8.28	8.35	8.33	8.40	9.77	10.21	10.75	11.60	12.46
Minnesota	7.49	7.65	7.92	8.28	8.70	9.18	9.74	10.04	10.59
Missouri	7.06	6.96	6.97	7.08	7.44	7.69	8.00	8.54	9.08
Ohio	8.24	8.26	8.45	8.51	9.34	9.57	10.06	10.67	11.32
Wisconsin	8.18	8.67	9.07	9.66	10.51	10.87	11.51	11.94	12.65
Midwest	7.82	7.90	8.04	8.19	8.78	9.24	9.78	10.29	10.78
U.S. Average	8.44	8.72	8.95	9.45	10.40	10.65	11.26	11.51	11.54

Table 7: Commercial Average Rates in the Midwest and U.S. (in cents).[18]

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Illinois	7.52	7.30	7.54	7.75	7.95	8.57	11.79	8.99	8.88
Indiana	5.98	6.12	6.31	6.57	7.21	7.29	7.82	8.32	8.38
Iowa	6.56	6.24	6.75	6.95	7.29	7.11	7.18	7.55	7.91
Michigan	7.79	7.55	7.57	7.84	8.51	8.77	9.20	9.24	9.81

[18] Source: U.S. Department of Energy, Energy Information Agency, Electric Sales and Revenue Data, Total Electric Industry (Form EIA-861), November 15, 2011.

Minnesota	5.88	6.12	6.31	6.59	7.02	7.48	7.88	7.92	8.38
Missouri	5.88	5.78	5.80	5.92	6.08	6.34	6.61	6.96	7.50
Ohio	7.81	7.55	7.75	7.93	8.44	8.67	9.22	9.65	9.73
Wisconsin	6.54	6.97	7.24	7.67	8.37	8.71	9.28	9.57	9.98
Midwest	6.88	6.81	6.98	7.20	7.62	7.91	8.84	8.57	8.83
U.S. Average	7.89	8.03	8.17	8.67	9.46	9.65	10.36	10.17	10.19

Table 8: Industrial Average Rates in the Midwest and U.S. (in cents).[18]

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Illinois	4.89	4.86	4.65	4.61	4.69	6.61	4.54	6.84	6.82
Indiana	3.95	3.92	4.13	4.42	4.95	4.89	5.46	5.81	5.87
Iowa	4.06	4.16	4.33	4.56	4.92	4.74	4.81	5.27	5.36
Michigan	5.02	4.96	4.92	5.32	6.05	6.47	6.74	6.99	7.08
Minnesota	4.07	4.36	4.63	5.02	5.29	5.69	5.87	6.26	6.29
Missouri	4.42	4.49	4.62	4.54	4.58	4.76	4.92	5.42	5.50
Ohio	4.87	4.79	4.89	5.10	5.61	5.76	6.19	6.71	6.40
Wisconsin	4.43	4.71	4.93	5.39	5.85	6.16	6.51	6.73	6.85
Midwest	4.51	4.56	4.63	4.86	5.24	5.66	5.65	6.32	6.33
U.S. Average	4.88	5.11	5.25	5.73	6.16	6.39	6.83	6.81	6.77

Fuel prices and purchased power cost increases, generation and transmission construction costs, and lost sales as a result of the recession are the significant drivers of recent rate increases. Increases to customers' bills can be mitigated with energy conservation and efficiency and innovative rate options. For example, the Commission recently approved an innovative rate program that is intended to promote increased economic development for WEPCO commercial, industrial, and institutional customers in its respective service territory. This real-time tariff pricing for WEPCO allows a customer with increased load to pay market rates for the increase in load, rather than tariff rates (rates based on embedded costs); a customer can sign up for a four-year contract. In addition, any selling of surplus energy to out-of-state utilities has the potential to help lower rates in Wisconsin, as indicated above. During 2010-2011, the Commission also approved an economic development rate program for WPL.

Since the 2008 recession, most of Wisconsin's electric utilities have experienced a decline in electricity sales as a result of a slowdown in business and increased efforts to conserve on the part of all ratepayers. Several utilities have asked for, and some have received, rate increases due in large part to the decline in electricity usage during that time period. Many ratepayers have expressed their anger and frustration publicly and directly to the Commission about utilities raising rates during a time when they are using less in order to reduce their energy costs. Recent rate increases during a general usage downturn are confusing to customers and require an understanding of fixed and variable costs to ultimately provide motivation to conserve.

ENERGY EFFICIENCY AND RENEWABLE RESOURCES

Energy Efficiency

STATUS OF ENERGY EFFICIENCY EFFORTS

Energy efficiency programs provide incentives and technical assistance for residents and businesses to install measures that reduce energy use and monthly bills. In 1999, state legislation created a third-party administered, energy efficiency program called Focus on Energy (Focus) for the benefit of electric and natural gas customers in Wisconsin. 2005 Wisconsin Act 141 moved oversight of Focus from the Department of Administration to the Commission, and set the funding level at 1.2 percent of investor-owned utility (IOU) annual revenue. Municipal and cooperative electric utilities are required to collect an average of $8 per meter per year, and have the option of using this revenue for either joining Focus or running their own energy efficiency program. As of 2011, all IOUs and municipal electric utilities are participants in Focus. Half of the twelve electric cooperatives run their own programs while half participate in Focus. Some utilities run energy efficiency programs within their service territories that provide additional benefits to their customers beyond what Focus offers.

Wisconsin Stat. § 196.374(3) requires the Commission to conduct a review of the Focus program; referred to as the quadrennial planning process. During the most recent review, goals and funding levels were reassessed. A Request for Proposal was sent out to parties interested in the role of Focus Program Administrator, and a new organization, “Shaw Environmental and Infrastructure, Inc.,” (Shaw) was selected. Shaw and the Statewide Energy Efficiency and Renewables Administration entered into a four year contract in May 2011.

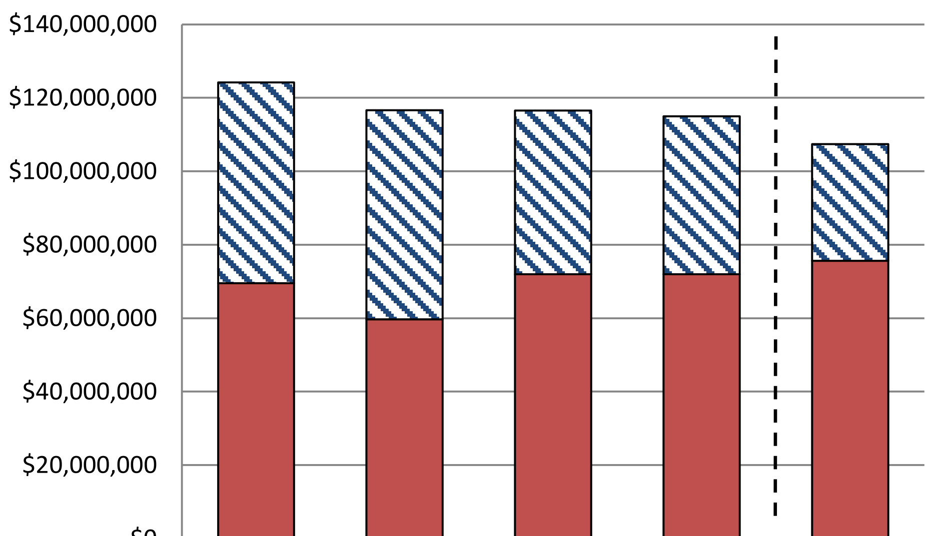
Since energy efficiency measures are investments, expenditures each year result in energy savings that persist for multiple years in the future depending upon types of measures installed. Independent program evaluators report on cost-effectiveness and take the persistence of savings into consideration. For 2010, the program evaluator for Focus conducted a simple cost-benefit analysis, and concluded that for every dollar invested, benefits valued at $2.30 are achieved. In order to realize energy savings on the electric side, it cost an average of 4.4 cents per kilowatt-hour (Cost of Conserved Energy). Only savings that the evaluator attributes to program implementation are counted in these analyses. This continual evaluation process allows the program to follow the objective of creating cost-effective reduction in energy use and demand that would not have occurred had the program not existed.

Focus spending decreased in 2011 because of reduced incentive levels and the transition to a new Focus administrator. 2012 expenditures are anticipated to increase to a slightly higher level than 2010, and remain flat for 2013. Over 2014-2018, a one percent annual increase in expenditures is projected due to light load growth that will result in a staggered increase in revenues from IOUs. The Commission set annual energy and demand goals for the Focus program at 10 percent above achievement for the 2009 calendar year. As a result, energy and demand forecasts are held constant at these levels from 2012-2018.

Given the large scale of Focus and utility energy efficiency expenditures, it is essential to include program savings when forecasting energy and demand needs from both utility and statewide perspectives. As part of this SEA, a forecast of energy and demand savings has been prepared by Commission staff for these programs. MGE, SWL&P, WEPCO, WPL, WPSC, NSPW, WPPI, and DPC all provide additional energy efficiency services. Some of the expenditures for these utility energy efficiency services include educational and behavior-based activities that do not have quantifiable savings. Figures 20, 21, and 22 provide forecasts through 2018 in terms of expenditures and first-year annual energy and demand savings.[19]

Utility energy efficiency expenditures will experience a decrease in program size. After 2013, the WPSC territory-wide energy efficiency programs will end, explaining most of the large drop in utility expenditures and projected savings.

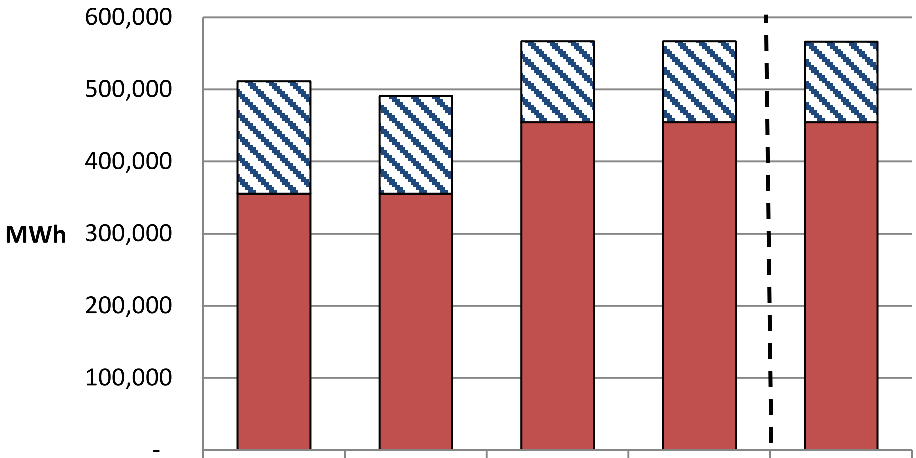
Figure 20: Annual Energy Efficiency Expenditures (2010-2018)[20]



	2010	2011	2012	2013	2018
Utility	$54,598,006	$56,943,697	$44,561,713	$43,015,373	$31,715,811
Focus	$69,583,390	$59,699,261	$72,000,000	$72,000,000	$75,672,724

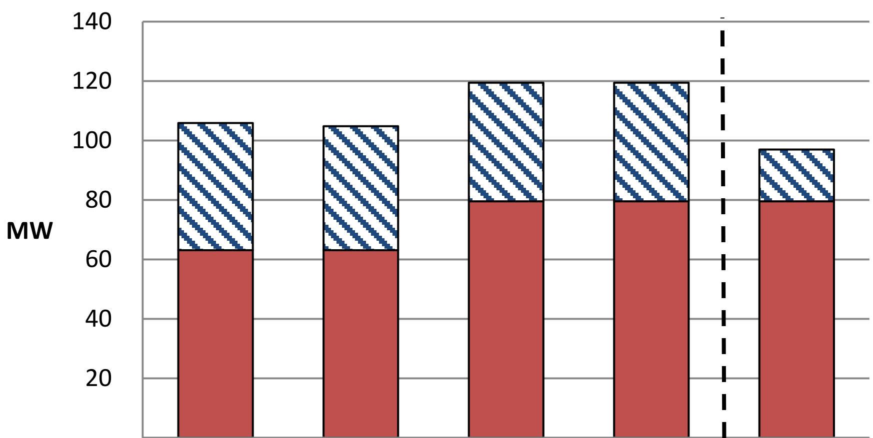
[19] Does not include persistent savings that occur multiple years after measures are installed.
[20] Source: Aggregated utility data responses, docket 5-ES-106; Focus on Energy 2010 Annual Report

Figure 21: First-Year Annual Energy Savings (2010-2018)[20]



	2010	2011	2012	2013	2018
Utility	155,506	135,219	112,581	112,656	111,801
Focus	355,419	355,419	454,059	454,059	454,059

Figure 22: First-Year Annual Demand Savings (2010-2018)[20]



	2010	2011	2012	2013	2018
Utility	43	42	40	40	17
Focus	63	63	80	80	80

In a joint agreement with the Citizens Utility Board and approval by the Commission, WPSC is implementing residential energy efficiency programs designed to engage customers with energy use information, as well as technologies such as in-home monitors and energy management devices that allow customers to view and better control their own energy use over time. The territory-wide program also has an Enhanced Energy Efficiency program that leverages Focus services to increase participation.

Customers in the WPSC pilot programs have the option of participating in Time-of-Use (TOU) rate structures that are based on the time of day and season of the year. The combination of information, incentives, technology, and rate structure will help customers save both energy and money on their bills by conserving and/or shifting their use during peak demand. Most utilities now offer TOU rates. Over 50,000 Wisconsin residential customers, about 2.5 percent of total residential customers, voluntarily opted into TOU rate structures in 2011. These dynamic rate elements in pilot programs will inform future customer engagement and rate designs. The goal is to flatten peak demand and reduce the need for power plants that are primarily constructed to run only during these times. This is important for system efficiency.

Utilities are also utilizing advanced technologies ("smart grid" technologies) to bolster efficiency and reliability on the supply side. As part of a federally-funded program, three utilities in Wisconsin received grants for smart grid projects that will enhance their distribution and transmission services. WPL received funding for a distribution automation project that will improve the efficiency and monitoring abilities at distribution level substations and capacitor banks. This will allow the utility to better optimize power flow for efficiency gains, as well as prevent, detect, and restore outages faster than before. MGE also received funding for distribution automation, as well as a plug-in electric vehicle pilot. The utility will have 12 public charging stations, and work with customers who purchase plug-in vehicles to install 25 in-home stations. Finally, ATC received two grants: one for phasor measurement units (PMUs) to better monitor and adjust power quality on their transmission system, particularly in rural areas, and one for a fiber optics communications system to retrieve data and maximize functionality from PMUs.

RENEWABLE RESOURCES

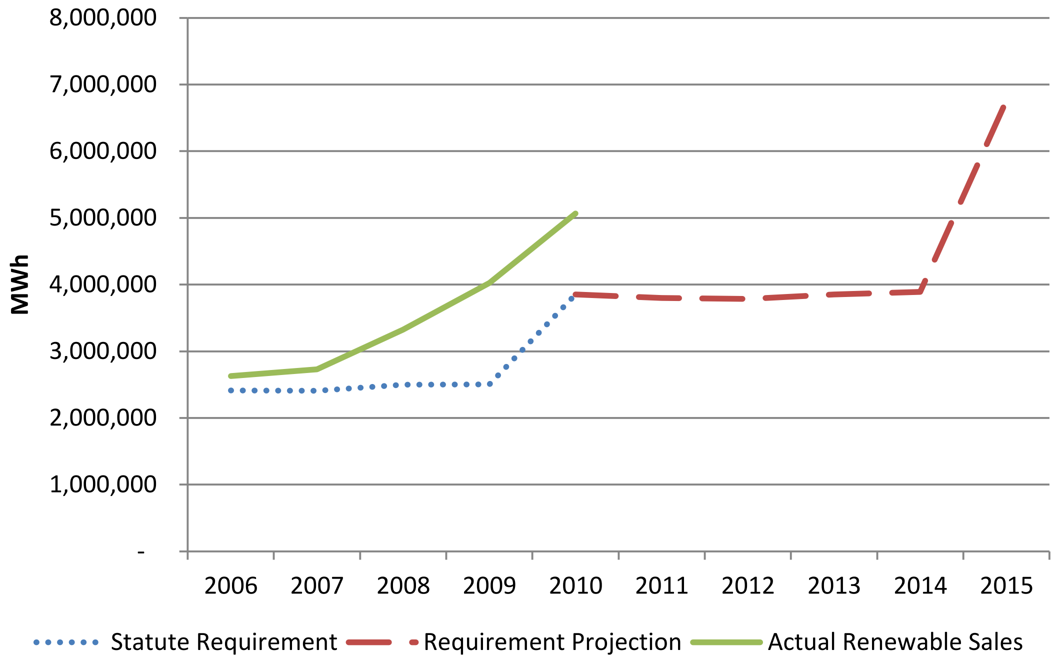
The main driver of large-scale renewable resource development for electric generation in Wisconsin is the Renewable Portfolio Standard (RPS).[21] It requires all Wisconsin electric providers to procure increasing amounts of electricity from renewable resources for retail electric sales through 2015. Each electric provider has a base renewable energy percentage, which is its average percent of electricity from renewable resources from 2001-2003. The RPS requires electric providers to increase their percentage by two percent above their baselines by 2010, by a total of six percent above their baselines by 2015, and to sustain this level thereafter. The overall effect of the RPS is to require 10 percent of Wisconsin's total electric energy consumption in 2015 (and thereafter) to come from renewable resources.

Through 2010, all electric providers have been compliant with their RPS requirements, and have nearly doubled statewide total retail sales from renewable resources over 2006-2010; from over 2.6 million MWh to over 5 million MWh. An average annual growth rate of 17.8 percent occurred during this time.

[21] Wis. Stat. § 196.378(2)

The statewide aggregate of actual renewable retail sales over RPS required sales levels is reflected in Figure 23.

Figure 23: Statewide RPS Renewable Retail Sales (Actual vs. Required, 2006-2015)[22]



Electric providers continue to add renewable resources to their portfolio of generation delivered to their retail customers, and are overall well-positioned to meet their requirements through 2015. Moving beyond 2010, Wisconsin as a whole must increase renewable sales at an average of approximately 6 percent annually, dependent upon future load growth, if it is to meet the overall RPS requirement of 10 percent of total retail sales from renewable resources by 2015.

Wind is the primary renewable resource used by Wisconsin electric providers, generating 54 percent of renewable electric retail sales in 2010.[23] Although hydroelectric generation makes up 30 percent of renewable resource generation, most of that is from facilities that were part of the electric providers' baseline of renewable resources, and therefore does not represent much of the incremental increase after 2006. A slim majority, 56 percent, of renewable resources are from facilities located in Wisconsin. Figure 24 breaks down 2010 electric sales from renewable resources by type and location. Figure 25

[22] Source: Commission Staff RPS Compliance Memo

[23] According to the Commission's Electric Provider Renewable Portfolio Standard Compliance report for 2010, 19 percent of Wisconsin's renewable energy came from Wisconsin wind, and 35 percent of Wisconsin's renewable energy came from out of state wind (docket 5-GF-206).

represents growth in sales from wind, hydro, and biomass from 2009 to 2010, and Figure 26 represents growth from solar photovoltaic (PV) sales.[24]

Figure 24: 2010 Renewable Sales by Resource and Location – Percent of Total Renewable Sales[22]

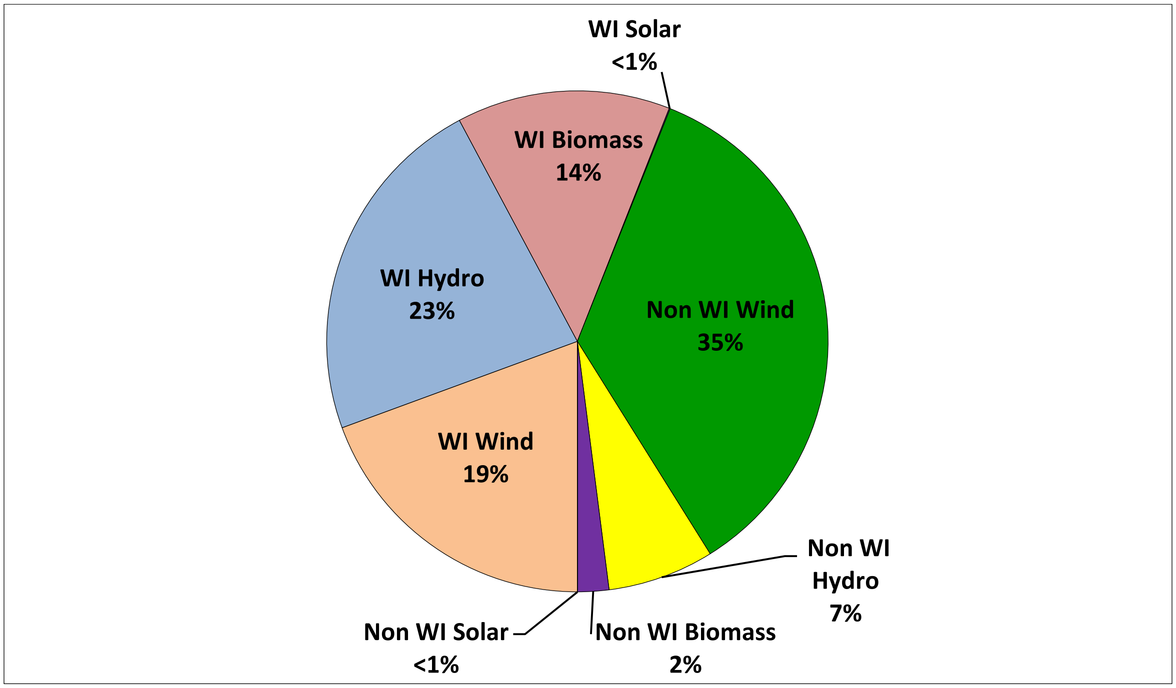
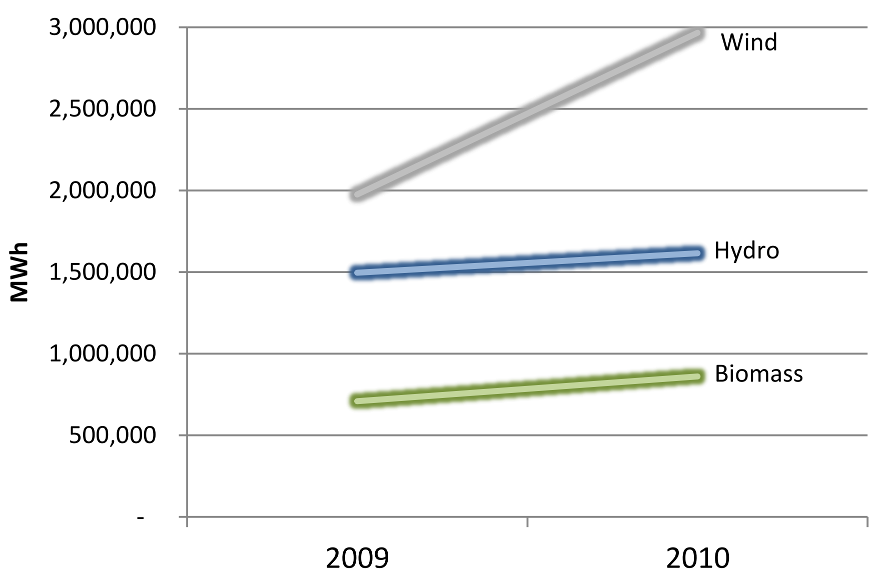
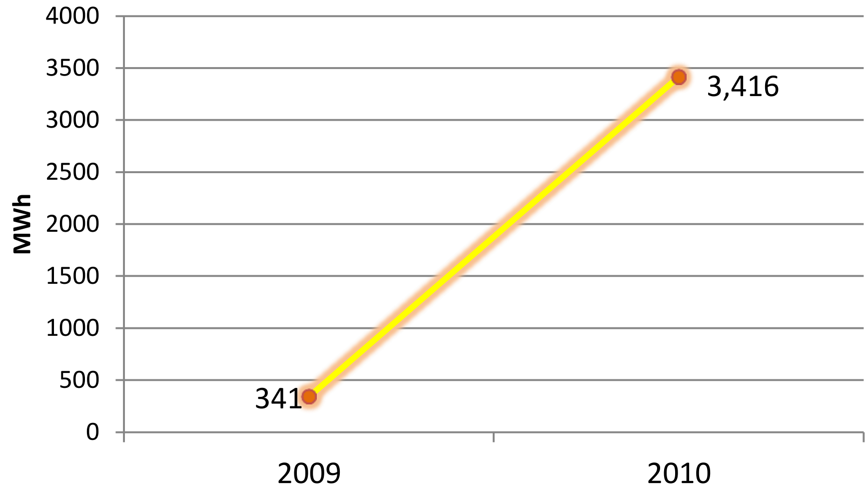


Figure 25: Wisconsin Utility Retail Sales by Renewable Resource[22]



[24] 2009 sales data do not contain all sales from utility voluntary green pricing programs.

Figure 26: Wisconsin Utility Retail Sales from Solar Photovoltaic[22]

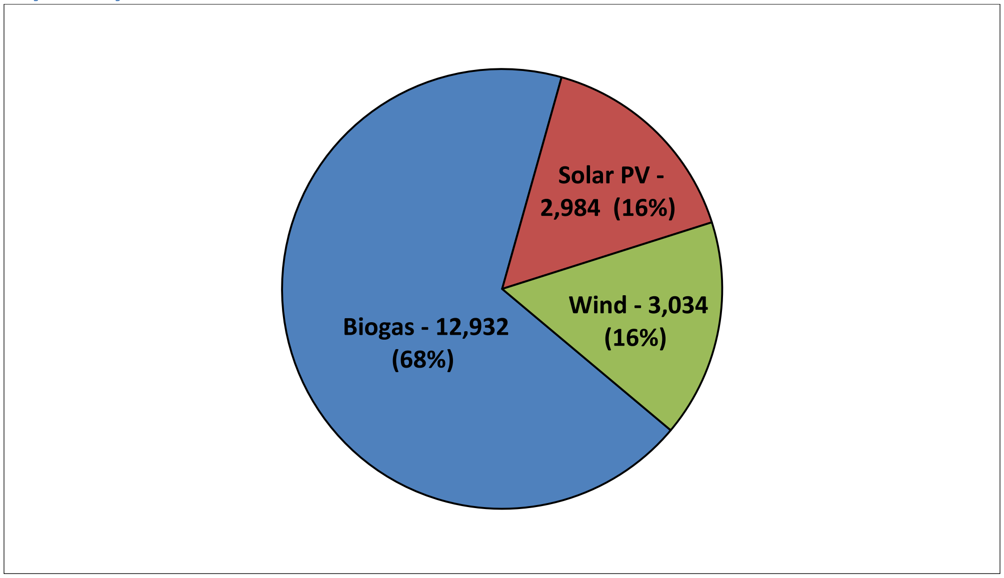


Whereas 2005 Wisconsin Act 141 only allowed hydroelectric generation from facilities under 60 MW in capacity to count as a renewable resource, 2011 Wisconsin Act 34 allows new, large hydroelectric facilities to also count towards RPS requirements starting in 2016. This will likely lead to hydroelectric generation growth used for RPS requirements in the future. Generation from wind and biomass resources will also increase as WEPCO is now generating electricity from the 162 MW Glacier Hills Wind Park, and is currently constructing the 50 MW Rothschild biomass plant. Solar PV generation growth will depend on customer implementation of on-site systems. WEPCO is also considering larger PV systems.

In addition to meeting their RPS requirements, some electric providers have voluntarily initiated efforts to foster renewable resource development. For retail customers willing to pay a slightly higher rate for electricity from renewable resources, electric providers have designed green pricing programs. These programs procure renewable resources beyond what the RPS requires based on demand of customers who opt-in to the program and voluntarily pay a premium. In 2010, over 378,900 MWh of electricity, approximately one half percent of all retail electricity sold in Wisconsin, was generated for voluntary green pricing programs.

Sales from customer-owned renewable, distributed generation are used to satisfy demand for some green pricing programs. Electric providers voluntarily design, and the Commission approves, advanced renewable tariffs (ARTs) to purchase renewable electricity from customers. ARTs are designed by renewable resource type, and often have capacity limits. Once enrolled, customers who place metered, renewable electric generation onto the distribution system are paid by the utility per kWh. While the majority of systems under ARTs in Wisconsin are solar photovoltaic, over two-thirds of the capacity enrolled comes from biogas. The rest of the capacity is made up of small wind turbines. Figure 27 represents 2011 capacity of distributed generation supported by Wisconsin utility ARTs.

Figure 27: 2011 Wisconsin Distributed Generation Capacity – Kilowatts (kW) (Percent of Total); Supported by Utility Advanced Renewable Tariffs



Source: Data provided by utilities

Focus provides incentives for many renewable distributed generation systems in Wisconsin. There are also Focus incentives for solar hot water systems that reduce natural gas use. According to the Focus evaluation report, over 1,500 kW of capacity was installed with the assistance of Focus in 2010 alone. Some of the generation from this capacity is used directly on-site, and some is bought by the electric utility and put on the local distribution system. Over two-thirds of the capacity was installed at business customer sites.

After Shaw assumed its role of program administrator in May 2011, it was discovered that renewable incentives paid to date were twice what had been budgeted for all of 2011. With the Commission’s decision to base avoided energy costs on a three-year historical average of locational marginal prices, Shaw was concerned that continuing this trend for the remainder of 2011 may result in the Focus program not being cost-effective. After Shaw presented the data and projections, the decision was made to continue to provide incentives for approved applications, but not to accept new business renewable applications until after a thorough review of the Focus portfolio of programs. Approved applications will result in $8 million in renewable incentives in 2012.

For 2012, 2013, and 2014, the Commission decided that a maximum budget of $10 million could be spent on renewable projects. For 2013 and 2014, the Commission also decided that this maximum funding level would be available as long as the overall benefit-cost ratio of the program remained at or above 2.3, and a reduction in energy savings of the portfolio of programs due to the inclusion of renewable resource measures does not exceed 7.5 percent. The Commission also allocated, for 2013 and 2014, 75 percent of the renewable incentives to biomass, biogas, and geothermal technologies, and 25 percent to solar thermal, photovoltaic, and wind technologies.

Appendix A

Table A-1: New Utility-Owned or Leased Generation Capacity, 2012-2016

Year	Type of Load Served	Capacity (MW)	Name	New or Existing Site	Owner/ Leaser	Fuel	Location (County: Locality)	PSC Status & Docket #
2012	Non-dispatchable[1]	0.7	Solar Facility	To be determined	WEPCO	Solar	To be determined	No application filed
2013	Base Load	50	Rothschild Biomass	Existing paper mill site	WEPCO	Biomass	Rothschild	Approved 6630-CE-305
2013	Intermediate Load	560	Riverside Energy Center	Purchase of existing unit	WP&L	Natural Gas	Beloit	No application filed
2014	Non-dispatchable[1]	1.1	Solar Facility	To be determined	WEPCO	Solar	To be determined	No application filed
2016	Non-dispatchable[1]	24	Wind Facility	To be determined	WEPCO	Wind	To be determined	No application filed
2017	Non-dispatchable[1]	24	Wind Facility	To be determined	WEPCO	Wind	To be determined	No application filed
2018	Non-dispatchable[1]	12	Wind Facility	To be determined	WEPCO	Wind	To be determined	No application filed
2018	Intermediate Load	749	Undetermined	Brownfield	WPSC	Natural Gas	To be determined	No application filed

[1]Nameplate MW shown. Wind operates when the wind blows and solar when the sun shines. Wind MW counted as firm are 20% per year average or less (more wind in winter than summer). Solar 15% average (seasonal differences to be determined later).

Source: Data provided by utilities.

Table A-2: New Transmission Lines[1] (on which construction is expected to start before December 31, 2018)

PSC Docket Number	Status	New Line or Rebuild/Upgrade[2]	Endpoints (Substations)	County	Voltage (kV)	Est. Cost (Millions)	Expected Construction	Expected In-Service	Substation Changes
American Transmission Company LLC (ATC)									
137-CE-158	Application Pending	Replace existing 18 mile 69 kV line with 161 kV	Monroe Co. - Council Creek	Monroe	161	31.2	Jun-12	Jun-13	New switching station
05-CE-139	Application Pending	New 3.0 mile 138 kV line	96th Street - Milwaukee County	Milwaukee	138	26.6	Jul-14	Apr-15	New Substation
137-CE-160	Application Expected 2013	New 118 mile 345 kV line	Cardinal - La Crosse area	Columbia, Dane, Jackson, Juneau, La Crosse, Monroe, Sauk, Trempealeau, Vernon[3]	345	405.0	Mar-16	Sep-18	
137-CE-162	Application Expected 2012	New 50 mile 345 kV line and new 16 mile 138 kV line	Barnhart - Branch River and Barnhart - Erdmann	Manitowoc, Sheboygan	345/138	162.6	Feb-16	Oct-18	Two new substations & 345/118 kV transformer at Barnhart and new termination at Erdmann. Cost for Barnhart - Erdmann included in Barnhart - Branch River
137-CE-166	Application Expected Late 2013	New 175 mile 345 kV line and 100 miles of 138 kV lines[5]	Green Bay - Plains	Brown, Outagamie, Oconto, and Dickinson, MI	345/138	Unknown	2015 [5]	2016 [5]	Expansion of existing substation[5]
Dairyland Power Cooperative (DPC), Northern States Power Company-Wisconsin (NSPW), and Wisconsin Public Power Incorporated (WPPI)									
No Docket Expected		Rebuild 20.8 mile 161 kV line	Genoa - La Crosse	La Crosse, Vernon	161	16.1	May-12	Jun-13	No
05-CE-136 in Part[4]		Rebuild 49.4 mile 161 kV line	Alma - La Crosse to Marshland	Buffalo, La Crosse, Trempealeau	161	43.8	Jan-17	Jan-19	No
No Docket Expected		New 0.5 mile 161 kV line	Lufkin - DPC 161 line	Eau Claire	161	0.5	Dec-12	Jan-13	New 138 kV sub at Lufkin
Northern States Power Company-Wisconsin (NSPW)									
4220-CE-176	Application Pending	New 17.5 mile 161 kV line	Stone Lake - Couderay	Sawyer	161	26.5	Jun-14	Dec-15	New Couderay 161/69 kV substation
4220-CE-173	Application Expected 2012	New 27 miles of 161 kV line	Osprey - Park Falls	Price, Sawyer	161	18.3	Oct-12	Jun-13	No
4220-CE-178	Application Pending	New 35 miles of 161 kV line	Radisson - Osprey	Rusk, Sawyer	161	40	Dec-12	Dec-14	New substation & expansion of existing substation
No Docket		New 70 miles of 115 kV line	Iron River - Bay Front	Ashland, Bayfield	115	60.4	2013	Jan-17	Yes

[1]Does not include lines approved by the Commission.
[2]Rebuilds and upgrades, as well as new lines, may require new right-of-way.
[3]Not all counties will be impacted depending on final route.
[4]Partly addressed by route approved for CapX project (05-CE-136).
[5]From www.atcllc.com
Source: Data provided by utilities.

Table A-3: Retired Utility-Owned or Leased Generation Capacity: 2012-2018

Year	Type of Load Served	Capacity (MW)*	Name	Owner/ Leaser	Fuel	Location (County: Locality)
2013	Peaking	28.5	Blount Street 5	MG&E	Gas, Coal	Madison
2013	Peaking	22.4	Blount Street 4	MG&E	Gas, Coal	Madison
2013	Peaking	39.2	Blount Street 3	MG&E	Gas, Coal	Madison

*Capacity listed is the summer net-accredited capacity
Source: Data provided by utilities.

Acronyms

§	Section
AC	Alternating Current
ART	Advanced renewable tariffs
ATC	American Transmission Company LLC
CA	Certificate of Authority
Commission	Public Service Commission of Wisconsin
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross State Air Pollution Rule
DATC	Duke Energy and ATC joint venture
DC	Direct Current
DOE	U.S. Department of Energy
DPC	Dairyland Power Cooperative
EHV	Extra High Voltage
EIA	U.S. Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States' Planning Council
EPA	U.S. Environmental Protection Agency
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
Focus	Focus on Energy
GLU	Great Lakes Utilities
IMM	Independent market monitor
IOU	Investor-owned utility
kV	kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LMP	Locational Marginal Pricing
MACT	Maximum Achievable Control Technology
MEP	Market Efficiency Project
MGE	Madison Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.
MPU	Manitowoc Public Utilities
MTEP	MISO Transmission Expansion Plan
MVP	Multi Value Project
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation
NO_x	Nitric oxides
NRC	Nuclear Regulatory Commission
NSPW	Northern States Power-Wisconsin
OMS	Organization of MISO states
PMU	Phasor measurement units
ROW	Right of way

RPS	Renewable portfolio standard
RTO	Regional Transmission Organization
SCR	Selective catalytic reduction
SEA	Strategic Energy Assessment
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SWL&P	Superior Water, Light and Power Company
TOU	Time-of-Use
WEPCO	Wisconsin Electric Power Company
Wis. Stat.	Wisconsin Statutes
WP&L	Wisconsin Power and Light Company
WPPI	Wisconsin Public Power, Inc.
WPSC	Wisconsin Public Service Corporation
Xcel	Xcel Energy, Inc.