WISCONSIN COUNTIES UTILITY TAX ASSOCIATION

44 East Mifflin Street, Suite 605A, Madison, Wisconsin 53703
Phone: (608) 250-4685

Agenda

May 6, 2016
WISCONSIN COUNTIES UTILITY TAX ASSOCIATION
10:30 A.M. – 1:00 P.M. (WORKING LUNCH)

CALL IN INSTRUCTIONS:
Conference Dial-in Number: (712) 432-0460
Participant Access Code: 115141#
(Be sure to hit # key after you enter the number, this will take you into the conference call) *If you are having trouble connecting, please call the main office and someone will assist you.*
608-250-4685 or call or text Alice's cell at 608 225 9391.

- Call to Order - Larry Wilkom
- Roll Call- Larry Wilkom
- Approval of Minutes of October 9, 2015 **(Attached)**
- President's Report – Larry Wilkom
- Treasurer's Report - Supervisor Linda Sinkula
  - Balance Sheet
- Executive Director Report – Alice O'Connor
- Invited not confirmed: PSC to discuss the Final Strategic Energy Report for Wisconsin 2018.
- Other suggestions?
- Next Board Meeting Date
- Adjourn

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February 5, 2016 MEETING MINUTES

The meeting was called to order at 10:30 by Chair Larry Willkom .The minutes from the October 9, 2015 were approved on a motion by Supervisor Goering seconded by Nick Osbourne.

Attendance: The following members were present: Larry Willkom, Chippewa County, William Goering, Sheboygan County: Herb Tennis, Washington County; Walt Christensen, Jefferson County; Chuck Hoffman, Manitowoc County; Robert Keeney, Grant County, Linda Sinkula, Kewaunee County.
Via Phone: Don Pazynski, Marinette County
Excused: John Tramburg, Columbia County: Richard Ott, Rock County

President's Report:

Chair Willkolm summarized the testimony before the Assembly Utility Committee and our discussions with Rep.Thiesfeldt on AB 490. He complimented Supervisor Walt Christensen and Supervisor Chuck Hoffman for their testimony as well and testimony presented by WCUTA Executive Director Alice O'Connor did an excellent job of letting the committee know that towns and counties should not be fighting with one another but rather, the state should be sharing more of its dollars they collect from power plants who don't pay local taxes.

Treasurer's Report - Supervisor Linda Sinkula
Supervisor Sinkula said the Beginning check book balance as of October 31, 20215b is $26,137.33 with a CD (#7379279) that matured January 31 and was rolled over until July 31, 2016 with a balance of $40,303.07.
This leaves a total of $66,440.40 in the checkbook. Expenses since October 31, 2015 were as follows:
November 2015 ($4,110.74); December 2015($1,920.00); January 2016 ($1,940.00) for a total of $3,860.00
2016 Dues checks continue to come in. This leaves a balance of $ 66, 440.40 in the Association bank account. The Treasurer's report was accepted on a motion by Supervisor Tennies, seconded by Supervisor Christianson.

Executive Director Report: End of session issues regulatory reform issues
Alice shared pages form the recent Legislative Fiscal Bureau Jan 30, 2016 showing the state had projected a budget based on a growth rate of 3.1 percent. But the state had only grown 2.94 percent. This has resulted in a $93 million dollar state deficit. With the failure of this legislature to deal with and replenish the broke Transportation Fund, the next legislature will face a $1 billion dollar problem.

The LFB report also said that utility tax revenue to the state in 2014 and 2015 were $381.8 MILLIONDOLLARS . These are projected to be reduced to $270.8 million in the 2015-2016 Session and $382.4 million in 2016-2017. The decrease in 2015-2016 reflects lower energy prices and last year's relatively warm winter.

Speaker Paul DE Wolfe Customer service manager We Energies- Discussed how their company delivers natural gas to rural areas. Mr. DeLong said there will continue to be discussion about the health effects of wind in the Fond du Lac and Brown County areas. He said when We Energies sites a project it goes through many phases. There are teams of people who study needs, environmental impact, and economic impact. Rock, wetlands, size of pipeline needed, load capacity, how to share costs if anyone is not current user, all are analyzed. He said they can't spread the cost of a project across all rate payers. It has to be those who are benefitting from it so they try to have as many people as customers as possible.

Tomah to Warrens want access to better gas. There is an agrument that the cost replacing LP gas with natural gas can be really costly. They like working joint trenches in rural areas to allow for other wires like broad band and phones lines too.

It was asked if a developer puts in so many lots and expands natural gas, will they get free pipes? Answer was no.

WPS and We energies are blending their connections.

Asked if they were involved in converting street lights to LEDs. He said until recently PSC had not approved rates for street lights and there is no standard rate. It depends on supply and cost to replace bulbs. That may change.

He suggested we have Joel Burrow (spelling?) come to discuss specific about the Riverside Power plant in Rock County, and if there will be repurposing. He said wind siting in St. Croix County and more windmills is likely three years down the road

After the speaker was done it was suggested the WCA reach out to the towns Association to see if there can be a discussion about increasing the utility tax funding for both counties and towns.

The meeting adjourned at 1:15 on a motion by Supervisor Tennies, seconded by Walt Christiansen

Next board meeting date: May 6, 2016, 10:30 at the Madison office

Public Service Commission of Wisconsin

Ellen Nowak, Chairperson
Phil Montgomery, Commissioner
Mike Huebsch, Commissioner

610 North Whitney Way
P.O. Box 7854
Madison, WI 53707-7854

For Immediate Release – March 24, 2016
Contact: Elise Nelson, 608-266-9600
elise.nelson@wisconsin.gov

Public Service Commission Issues Draft Strategic Energy Assessment

(Madison) -Today the Public Service Commission of Wisconsin issued a draft version of "Energy 2022," Wisconsin's biennial, statutorily-required, strategic energy assessment. The draft is currently available for public comment and review.

"Energy 2022" outlines ongoing issues to help Wisconsin maintain reliable electric service and a balanced energy portfolio, providing stable rates for customers.

The Commission is asking the public to comment on the draft report, which is accessible at: www.psc.wi.gov. Based upon the comments received on the draft, the Commission will issue a final report.

Comments may be submitted in the following ways:

- Public Hearing
  May 11, 2016
  1 - 3 p.m.
  Public Service Commission
  Amnicon Falls Hearing Room
  610 N. Whitney Way
  Madison, WI 53707

- By letter addressed to:
  Docket 5-ES-108
  Public Service Commission of Wisconsin
  PO Box 7854
  Madison, WI 53707

- Electronically at the PSC website: www.psc.wi.gov

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PUBLIC SERVICE COMMISSION OF WISCONSIN

FINAL

STRATEGIC ENERGY ASSESSMENT

ENERGY 2018

610 NORTH WHITNEY WAY
MADISON, WISCONSIN

NOVEMBER 2012
DOCKET 5-ES-106

TO THE READER

This is the seventh biennial Strategic Energy Assessment (SEA) issued by the Public Service Commission of Wisconsin (Commission), an independent state regulatory agency whose authority and responsibilities include 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 the final SEA. A public hearing was held on August 28, 2012, and a copy of the notice providing information on the hearing is available for review on the Commission's website at: http://psc.wi.gov.

The Commission must also make an environmental assessment on the draft SEA before the final report is issued. The environmental assessment is available on the Commission's website.

Public comments have been used to prepare the final SEA. Questions regarding the final SEA or requests for additional copies of the final 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.

Public Service Commission of Wisconsin
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Home Page: http://psc.wi.gov

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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 hearing(s) 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, is to be issued 30 days prior to the public hearing.

The 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.[1] Should a specific topic warrant further attention with the intent of Commission action, the Commission must take additional steps as authorized by law.

[1] Wis. Stat. § 196.491(3)(dm)

EXECUTIVE SUMMARY

DEMAND AND SUPPLY OF ELECTRICITY

- The recent economic downturn has translated into lower peak demand growth in Wisconsin. Wisconsin utilities forecast between 0.3 percent and 1.7 percent annual load growth through 2018. This is similar to the 1.0 percent forecast from the last SEA.
- Wisconsin's primary energy source is coal.
- The increased presence of renewable projects in Wisconsin continues to change the generation mix proportions in the state.

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 11.6 percent through 2018. The planning reserve for the critical 2013-2014 period is 16-22 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, distribution 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. Some of these increases, however, have been, and are expected to continue to be, offset by the lower cost of natural gas.
- 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 law requires Wisconsin's electric providers to sell a certain percentage of renewable energy.[2] 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 (2011), and over 9.5 percent of all electrical energy sold in Wisconsin, including RPS and voluntary green pricing retail sales, 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 may 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.

[2] 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)[3]

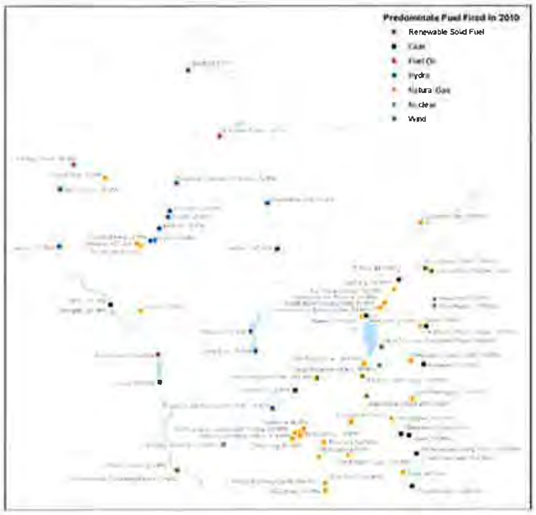


Table 1 shows the aggregated responses of the entities providing data for this SEA. The current planning reserve margin requirement for the Midwest Independent Transmission System Operator, Inc. (MISO) footprint is 17.4 percent; yet this margin is affected by diversity factors. Diversity factors take 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.

[3] On October 22, 2012, Dominion publicly stated its intent to permanently shut down the Kewaunee Nuclear Power Plant in the second quarter of 2013.

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

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
						Forecasted Planning Values				
Summer Peak Electric Demand (MW)										
Date of Peak Load										
Date of Peak Load	June 23	August 12	July 20	July 17						
Peak Load Data and Forecast (non-coincident)	13,705	14,102	14,913	15,028	14,609	14,759	14,908	15,048	15,208	15,354
Direct Load Control Program	(31)	(53)	(108)	(84)	(208)	(208)	(209)	(210)	(210)	(211)
Interruptible Load	(20)	(16)	(13)	(67)	(604)	(608)	(656)	(658)	(659)	(661)
Capacity Sales Incl. Reserves	573	542	531	600	583	539	546	547	582	583
Capacity Purchases Incl. Reserves	(464)	(562)	(606)	(463)	(614)	(555)	(492)	(507)	(513)	(522)
Miscellaneous Demand Factors	(131)	(132)	(127)	(121)	(138)	(138)	(73)	(73)	(73)	(73)
Adjusted Electric Demand	13,432	13,882	14,590	14,693	13,628	13,789	14,024	14,146	14,336	14,470
Electric Power Supply (MW)										
Owned Generating Capacity (in-, or used, for- Wis. cust.)	13,265	13,156	13,873	13,957	13,602	14,156	14,417	14,375	14,403	14,400
Merchant Power Plant Capacity Under Contract (in, or used, for Wis. cust.)	4,015	3,937	3,621	3 559	2 853	2,196	1,970	1,719	1,714	1 708
New Owned or Leased Capacity/Additions	15	99	158	33	583	59	90	90	90	465
Net Purchases W/O Reserves	(1,593)	(1,277)	(1 554)	(976)	(105)	(119)	33	21	58	61
Miscellaneous Supply Factors	(220)	(330)	(544)	(806)	(318)	(332)	(266)	(224)	(260)	(235)
Electric Power Supply	15,482	15 586	15 555	15,767	16,614	15,961	16,245	15,981	16,006	16,399
Calculated Data										
Reserve Margin	15.3%	12.3%	6.6%	7.3%						
Planning Reserve Margin					21.9%	15.8%	15.8%	13.0%	11.6%	13.3%
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 2012 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 2012, resulting in net sales of 976 MW. Because sales result in a reduction of the amount of reserves available, the7.3 percent operating reserve margin value for 2012 likely understates the supply adequacy for Wisconsin in that particular year. Future forecast years suggest fewer expected net sales compared to 2012; realistically however, the decision to enter contracts to sell excess capacity is likely to be weighed by the utilities in real time. An examination of both peak demand figures for the recent past, and reserve margin forecasts in the future, confirms 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. The reserve margin forecast for 2013 is nearly 22 percent, and is expected to remain above 11.6 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	10,934	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	14,829	13,561	13,038	9,681	10,032	10,567
2012	10,574	9,984	9,764	8,968	10,347	13,941	15,062	13,341	12,887			
Forecasted												
2012										10,308	10,410	11,168
2013	11,049	10,763	10,309	9,833	10,528	13,360	14,533	14,194	12,507	10,343	10,413	11,203
2014	11,160	10,871	10,416	9,924	10,617	13,510	14,683	14,344	12,625	10,435	10,490	11,301
2015	11,259	11,006	10,561	10,048	10,720	13,704	14,835	14,499	12,787	10,591	10,611	11,416
2016	11,364	10,993	10,653	10,148	10,798	13,844	14,973	14,643	12,927	10,674	10,694	11,505
2017	11,486	11,230	10,761	10,264	10,907	14,009	15,142	14,810	13,070	10,778	10,784	11,612
2018	11,602	11,338	10,868	10,369	11,003	14,159	15,294	14,958	13,203	10,879	10,865	11,712

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. Utilities estimate increases in non-coincident peaks to be between approximately 0.3 and 1.7 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.[4] 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 2012, up to 108 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.

[4] 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	269	679
Forecasted			
	2012	237	685
	2013	208	604
	2014	208	608
	2015	209	656
	2016	210	658
	2017	210	659
	2018	211	661

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 2013 planning reserve margin is 21.9 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[5]

Planning Year	Final SEA 2000	Final SEA 2002	Final SEA 2004	Final SEA 2006	Final SEA 2008	Final SEA 2010	Final 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	6.6
2012				17.4	18.5	25.8	7.3
2013					14.4	24.9	21.9
2014					11.0	20.1	15.8
2015						18.7	15.8
2016						15.1	13.0
2017							11.6
2018							13.3

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 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.

[5] The Planning Reserve Margin (PRM) as shown in Table 4 for 2016 and 2017 is less than the 14.5 percent required under the Commission's 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.

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)

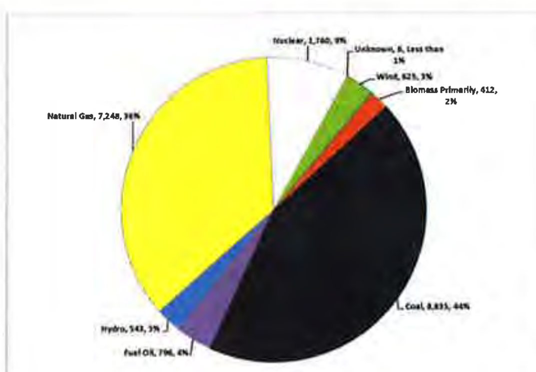
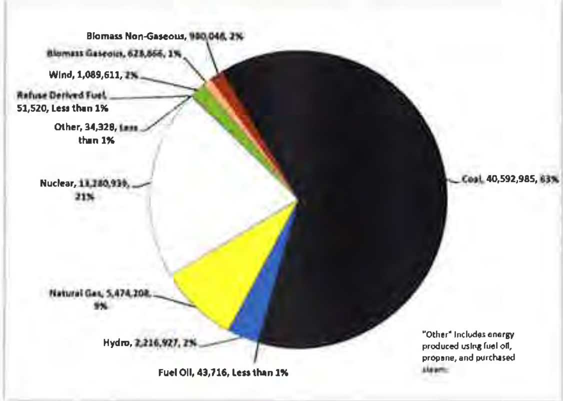


Figure 3 indicates actual generation by fuel from most recent data. Wisconsin's actual energy generation proportions differ greatly from the state's nameplate capacity. Approximately two thirds of actual generation is supplied from coal and only about 9 percent of actual generation comes via natural 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[6]

Between the beginning of 2010 and this 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

[6] 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.

were renewable energy projects, projects which were proposed to meet Wisconsin's Renewable Portfolio 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 significant 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	Complete	SCR/FGD	1959	$830.0
Oak Creek 6	WE	Complete	SCR/FGD	1961	Included in above
Oak Creek 7	WE	Complete	SCR/FGD	1965	Included in above
Oak Creek 8	WE	Complete	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	$288.0
Edgewater 5	WPL	Anticipated	FGD	1985	$440.0
				Total	$2,728.8

* 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. On October 22, 2012, the Kewaunee Nuclear Power Plant owner, Dominion, announced plans for the plant's closure in 2013 due to economic concerns.

Wisconsin currently has capacity beyond the minimum required planning reserve margin for several years. However, changes to Wisconsin's generation fleet, such as the Kewaunee Nuclear Power Plant closure, 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.

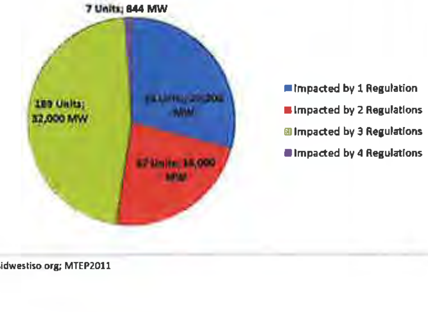
Wisconsin utilities still generate a strong majority of our state's daily electricity and any exports through base load coal generation facilities. Depending on the exact compliance rules implemented as part of EPA's environmental regulation, Wisconsin utilities may have to respond with new or retrofitted 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.

EPA finalized a mercury and air toxics rule and published the rule on February 16, 2012. The rule 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.

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 2015-2017, depending on legal challenges. 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 4 below is an estimated breakdown by MISO of the rule impacts on these units. Note that this chart was developed in 2011, before CSAPR was overturned. There will, however, likely be a similar number of units impacted for two reasons:

1. The EPA is obligated to implement CAIR (as a replacement for CSAPR) in some form or fashion.
2. More restrictive National Ambient Air Quality Standards for Sulfur Dioxide are now published and become effective in 2018

Figure 4: 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;
- Better economics or increased market efficiency;
- Generation interconnection agreements and transmission service requirements for proposed (or approved) new power plants; and
- Maintenance of transmission system reliability and performance.

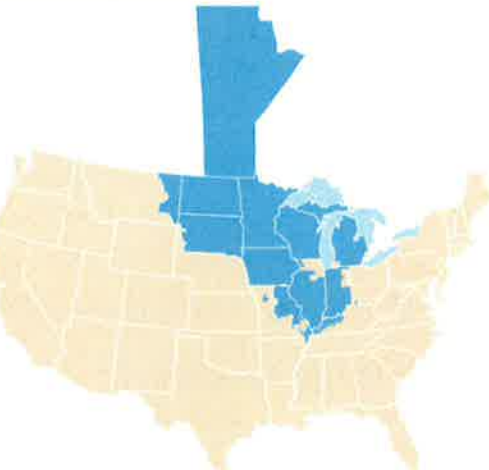
In general, the higher a line's voltage, the more power it can carry and losses are reduced. As a consequence, the higher voltage transmission lines are important in delivering large amounts of power on a regional basis, and the lower voltage lines primarily deliver power over a more limited area. The 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 5, 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.

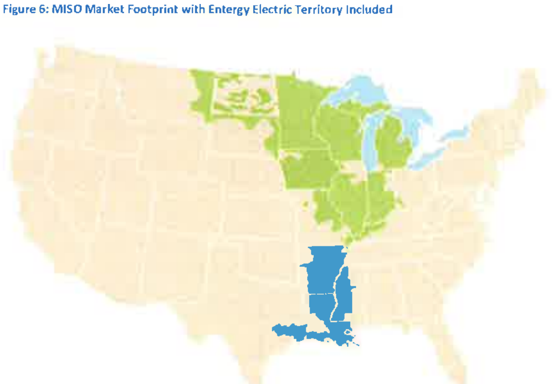
Figure 5: MISO Reliability Coordination Area



Source: www.midwestiso.org

One new development is the potential integration in the MISO footprint of Entergy utilities to the south. On August 2, 2012, Entergy filed a request with FERC requesting authorization to transition the Independent Coordinator of Transmission Functions from SPP to MISO. 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 would add 15,000 miles of transmission and 30,000 megawatts of generation capacity into the MISO footprint. Figure 6 shows the MISO market footprint with Entergy utilities included. On September 4, 2012, MISO and Entergy began parallel operations. The parallel operations will continue until December 1, 2012. Also on September 4, 2012, Entergy filed in Louisiana to transfer its 69 kV and larger transmission assets to ITC Holdings. On October 25, 2012, the Texas Public Utility Commission voted to conditionally approve Entergy Texas' request to join MISO, and on October 26, 2012, the Arkansas Public Service Commission issued an order supporting Entergy Arkansas' change of control request to join MISO.

Figure 6: MISO Market Footprint with Entergy Electric Territory Included



Source: www.midwestiso.org

MISO TRANSMISSION PLANNING – OBJECTIVES AND SCOPE[7]

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.

MISO controls reliability operations (engineering aspects) for approximately 142,930 MW of generation capacity in a reliability footprint with a peak load of approximately 110,032 MW. MISO runs an energy market (economic operations) for 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 estimates that integration of the Entergy region will add approximately 15,500 miles of transmission and 21,799 MW of non-coincident load into MISO.

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.

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

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. 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. If Dominion files a request for the closure of the Kewaunee Nuclear Power Plant, as is anticipated, MISO will conduct a grid stabilization study to determine if the grid will remain reliable with the loss.

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.[8] 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

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

queue related and operational studies. Almost simultaneously, a multiple regional effort known as 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 (RTOs), 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 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.[9]

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. 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 construction. 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 should be built. The MISO Board does not approve the construction of a project. MISO in MTEP only determines if the project will work with its system, and under the federal tariff, whether the projects costs can be shared. Actual project construction, siting and need determination remains a state public utility commission function.

[9] 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.

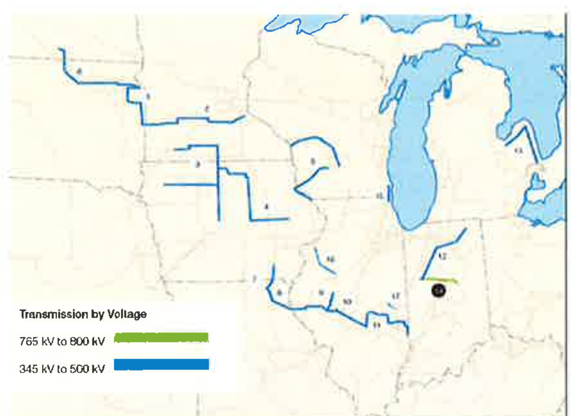
In December 2011, MISO approved the MTEP11 cycle report. MTEP11 contains 215 new projects that represent an incremental $6.5 billion in transmission infrastructure investment within the MISO footprint and fall into the following four categories:

- Multi Value Projects (MVP) – projects providing regional public policy, reliability, and/or economic benefits – 16 projects, $5.1 billion;[10]
- Baseline Reliability Projects (BRP) – projects required to meet North American Electric Reliability Corporation (NERC) reliability standards – 40 projects, $424 million;
- Generator Interconnection Projects (GIP) – 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 potential 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 in Figure 7.

Figure 7: Map of MISO Approved Multi Value Projects

[10] 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.

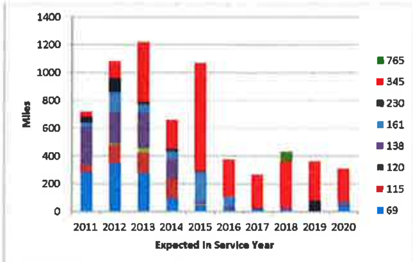


2011 Multi-Value Project Portfolio		
Project Name	State(s)	Voltage
1. Big Stone – Brookings	SD	345 kV
2. Brookings – SE Twin Cities	SD/MN	345 kV
3. Lakefield Jct. - Winnebago - Winco – Burt area & Sheldon – Burt area – Webster	MN/IA	345 kV
4. Winco – Lime Creek – Emery- Blackhawk – Hazleton	IA	345 kV
5. N. La Crosse-N. Madison-Cardinal & Dubuque Co.-Spring Green-Cardinal	WI	345 kV
6. Ellendale – Big Stone	ND/SD	345 kV
7. Adair – Ottumwa	IA/MO	345 kV
8. West Adair – Palmyra Tap	MO	345 kV
9. Palmyra-Quincy-Meredosia-Ipava & Meredosia-Pawnee	MO/IL	345 kV
10. New Pawnee-Pana	IL	345 kV
11. Pana-Mt. Zion-Kansas-Sugar Creek	IL	345 kV
12. Reynolds-Burr Oak-Hiple	IN	345 kV
13. Michigan Thumb Loop Expansion	MI	345 kV
14. New Reynolds-Greentown	IN	765 kV
15. Pleasant Prairie-Zion Energy Center	WI/IL	345 kV
16. Fargo-Oak Grove	IL	345 kV
17. Sidney-Rising	IL	345 kV

Source: www.midwestiso.org

The majority of approved projects are categorized as baseline reliability projects, generation interconnection projects, or "other" projects. Figure 8 shows a total of approximately 3,695 miles of new and 2,965 miles of upgraded lines in the 2011-2021 time period.

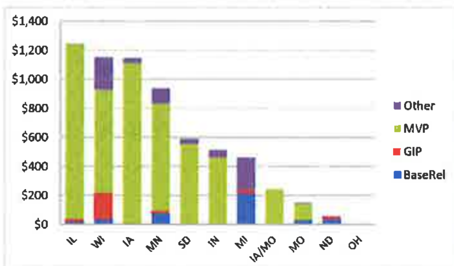
Figure 8: MISO Transmission Voltage, Mileage, and Expected In Service Date



Source: www.midwestiso.org

Figure 9 shows how the approved project types in MTEP 11 are shared among the MISO states.

Figure 9: 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.[11]

NORTHERN AREA STUDY (NAS)

In June 2012 MISO initiated a planning effort that is referred to as the Northern Area Study (NAS). A Technical Review Group (TRG) will be the primary forum for stakeholder input into this planning effort. The primary impetus behind the NAS results from a number of factors, including:

- Potential addition of generation and imports from Manitoba Hydro;
- Potential generation retirements driven by EPA regulations;
- Multiple transmission owners having submitted proposed transmission plans in the area;
- Potential load growth in Michigan Upper Peninsula, northern Wisconsin, and North Dakota; and
- The need to improve system reliability in the study area.

Figure 10 depicts the NAS geographic map. The detailed electric transmission area immediately adjacent to Manitoba and the states of North Dakota, Minnesota, Wisconsin, and Michigan will be monitored in the study.

Figure 10: Northern Area Study Geographic Map

Source: www.midwestiso.org

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

The NAS will be coordinated with other MISO studies, including the American Transmission Company Out of Cycle projects study and the Manitoba Hydro Wind Synergy Study. The NAS timeline includes monthly updates to the MISO Planning Advisory Committee. The work includes market economics and thorough reliability analysis. The first full report is projected to be complete in the beginning of 2013, followed by stakeholder communications and updates. The project closeout is targeted for June of 2013.

AMERICAN TRANSMISSION COMPANY (ATC)

ATC is a for-profit, transmission-only utility, which was formed under Wis. Stat. § 196.485. 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 Public Service Commission of Wisconsin 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.

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,[12] 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.[13]

[12] ATC – *2011 10-Year Transmission System Assessment Summary Report*; http://www.atc10yearplan.com.
[13] FERC, Order 890.

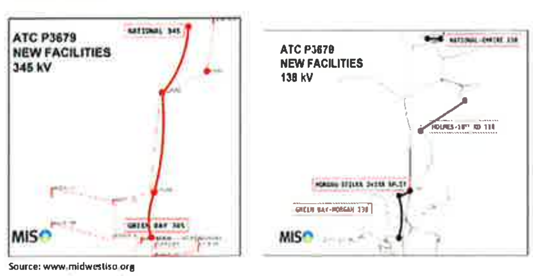
RECENTLY PROPOSED RELIABILITY PROJECTS[14]

Several recently proposed 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. See figure 11 below:
  - Expected In Service Dates: 2016-2018
  - 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. This project is dependent on the results of the MISO Northern Area Study. See green elliptical area in Figure 12.
  - Expected In Service Date: 2017
  - Estimated Cost: Approximately $400 million (planning level)
  - System Need: Reliability

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

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

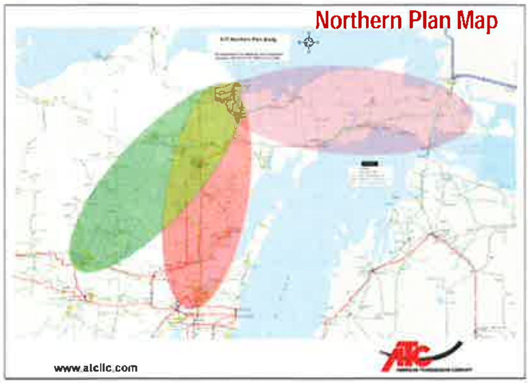


Source: www.midwestiso.org

[14] 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.

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

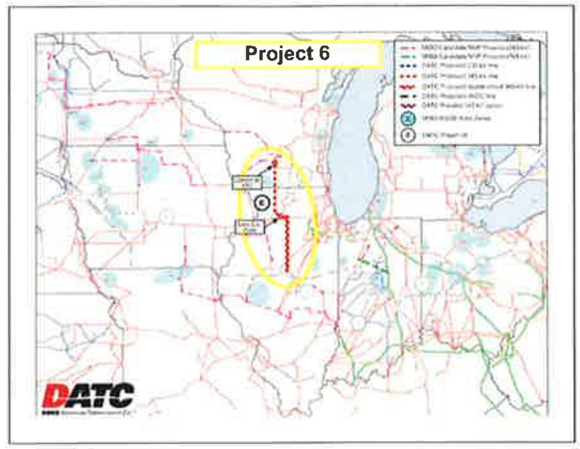


Duke Energy and ATC have formed a joint venture LLC organization (DATC) and are proposing Extra High Voltage (EHV), Alternating Current (AC), and High Voltage Direct Current (DC) in the West and Midwest. DATC presented two projects in the Wisconsin area at the December 2011 Sub-regional Planning Meeting. 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.

- DATC P3675 – 345 kV line from South Central Wisconsin to Central 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



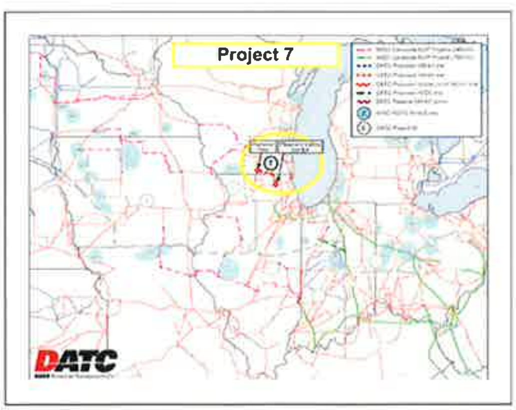
Source: www.datcllc.com

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 shows a map depicting the approximate transmission routing.

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



Source: www.datcllc.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. FERC subsequently issued a clarification

Order 1000A that made additional policy changes affecting transmission projects which are cost shared across the MISO footprint.

MISO believes it is mostly compliant with FERC Orders 1000 and 1000A, but needs to expand documentation of some processes. Beginning in 2013, states will have a larger role in MISO transmission planning. That role will be through OMS and via direct input from a state to MISO during transmission planning and any competitive evaluations that take place in each annual transmission plan and evaluation that MISO conducts. MISO's initial FERC compliance filing was made on October 25, 2012.

FERC Orders 1000 and 1000A specifically require:

- 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 Orders 1000 and 1000A establish cost allocation principles for regional and interregional transmission facilities as well as for any transmission project that is cost shared. The allocated costs should generally be commensurate with established benefits. Different types of transmission facilities can have different allocation methods. FERC issued a subsequent clarification order, 1000-B, on October 18, 2012 that affirms the requirements of Order 1000 and 1000-A, including that each utility transmission provider must participate in a regional planning process. Furthermore, Order 1000-B affirms that transmission facilities located in two neighboring transmission planning regions be jointly evaluated by the two regions in the interregional transmission coordination process.

A key item that has emerged is the removal of any federal rights of first refusal from FERC-approved tariffs and agreements for transmission projects that are cost shared. Essentially, the FERC orders require that any cost shared project now be subject to competitive evaluation in order to reduce costs to ratepayers. In MISO's October 2012 draft-tariff wording, transmission projects that are MEPs or MVPs will now have to undergo competitive evaluation by MISO with the assistance of the states affected. Wisconsin will likely take a larger role in such a MISO competitive evaluation.

As part of the development of competitive bidding, and because FERC requires that projects that are cost-shared be subject to competitive bidding, MISO is proposing that present cost shared Baseline Reliability Projects no longer be cost-shared, and that the incumbent utility have the sole right to build any reliability projects. That is, there would be no competitive bidding. The disappearance of cost-sharing for large baseline reliability projects is a controversial policy issue. It is a policy issue that the Commission will weigh in on at MISO. Within MISO, most transmission-owning utilities are requesting the MISO-proposed change, as they want to ensure that some projects will remain within their sole-construction jurisdiction.

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, but other factors subsequent to the initial data presented here may change the margin.

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 period, 2014-2018, electricity providers are required to plan for 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,[15] 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.

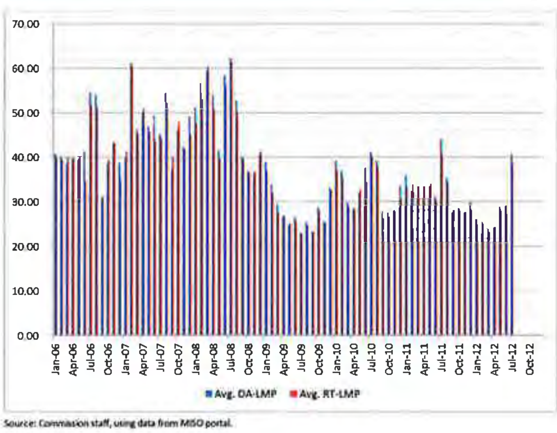
Extent to which Effective Competition[16] Contributes to a Reliable, Low Cost, and Environmentally Sound Electricity Source

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. For a broader view of the complete MISO wholesale energy market, Figure 15 displays wholesale energy market prices in MISO since the start of the first year of the market beginning in 2006.

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

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

[16] 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."



Source: Commission staff, using data from MISO portal.

A report by MISO's independent market monitor (IMM), entitled "State of the Market 2011," published in June 2012, provides evidence that MISO's wholesale energy markets were competitive with market clearing prices less than 1.30 percent higher than IMM's estimated reference-level marginal costs. IMM also concluded that the marketplace experienced appropriate price convergence, with only minor output withholding which could effectuate non-competitive prices.[17] This demonstrates that the MISO markets and Wisconsin entities' participation in such markets are properly bounded by effective competition.

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.

[17] Potomac Economics, Dr. David Patton, *2011 State of the Market Report for the Miso Electricity Markets*, June 2012,https://www.midwestiso.org/Library/Repository/Report/IMM/2011%20State%20of%20the%20Market%20Report.pdf.

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.

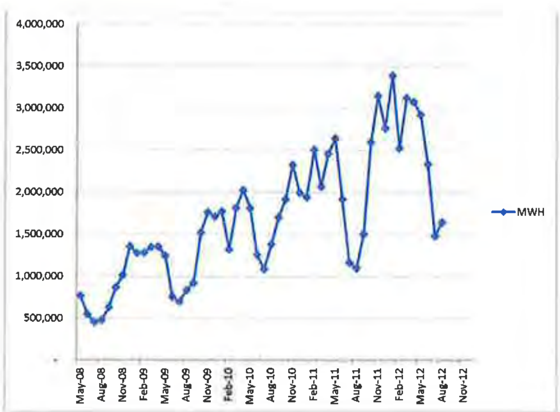
Assessment of Whether Sufficient Electric Capacity and Energy will be Available to the Public at a Reasonable Price

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 by the year 2015. 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 16 displays the growing presence of wind energy in the MISO footprint as well its variability due to changes in weather.

Figure 16: Monthly Wind Generation in MISO



Source: www.midwestiso.org

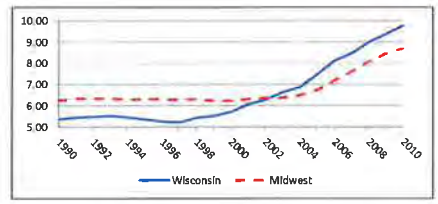
Due to the strong construction program of 2000-2010 and decreased energy consumption and growth in peak demand because of the recent recession, such developments have tempered the need for new capacity. The Commission will continue to carefully weigh the need for new capacity, as well as the optimal 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 partially 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 a 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 seek 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 17, the recent 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 to retail customers in the Commission's rate setting process.

Figure 17: Average Rates in Wisconsin and the Midwest[18] 1990-2010



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

[18] 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), Mercury and Air Toxics Standard (MATS)rule, Cooling Water Intake, greenhouse gas regulations, and revised SO2 standards, will likely increase the operating costs of Wisconsin utilities. MISO estimates 12.2 gigawatts (GW) of coal units (MISO compliance survey as of 9/26/2012) in the MISO footprint could 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. MISO forecasts that the expected retirements in this range will not make the footprint fall below the planning reserve margin requirement. 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.

Several of the environmental laws are under review and/or being challenged at the time of this writing. Here are some examples of the legal challenges and/or that have occurred in recent months in regard to proposed or current EPA laws. These challenges and/or delays have led to considerable uncertainty for generating units.

- EPA rules on greenhouse gas regulations – June 26, 2012: EPA's landmark greenhouse gas regulations were upheld.
- Cooling Water Intake Structures – CWA 316(b) – July 17, 2012: EPA secured an additional year to finalize standards for cooling water intake structures under section 316(b) of the Clean Water Act, under a modified settlement agreement. EPA is working to finalize the standards by June 27, 2013.
- Primary National Ambient Air Quality Standard for Sulfur Dioxide – July 20, 2012: The U.S. Court of Appeals upheld stricter SO2 limits. EPA first set standards for SO2 in 1971. EPA set a 24-hour primary standard at 140 ppb and an annual average standard at 30 ppb (to protect health). EPA also set a 3-hour average secondary standard at 500 ppb (to protect the public welfare). The 2010 rule restricted emissions over the course of an hour to 75 parts per billion, tightening the previous standard.
- Primary National Ambient Air Quality Standard for Sulfur Dioxide – July 27, 2012: Regarding the new 1-hour standard, EPA issued a notice that the deadline for area designations for the 2010 primary sulfur dioxide (SO2) national ambient air quality standard if being extended for up to one year. EPA intends to make area designations for the 2010 primary SO2 standard by June 3, 2013, instead of June 2012. EPA strengthened the primary air quality standard for SO2 in 2010.
- Mercury and Air Toxics Standard (MATS) – July 27, 2012: A partial stay of the new rule for up to three months for new source standards was issued by EPA. EPA published the final version of the law on February 16, 2012, which allows three years plus an additional 1-2 years depending on circumstances such as the effect on reliability of the electrical system.

- EPA Cross State Air Pollution Rule (CSAPR) – August 21, 2012: The U.S. Court of Appeals for the District of Columbia Circuit ruled in a 2-1 decision (*EME Homer City Generation, L.P v. EPA*) that EPA exceeded its statutory authority with CSAPR. CSAPR was finalized in July 2011 and replaced the Clean Air Transport Rule, signed on July 6, 2010, which was challenged as not strict enough. Please note that the EPA filed on October 5, 2012 for an en banc hearing and as of the report, no other deadlines or decisions have been made.

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)[19]

	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).[19]

	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
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

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

Table 8: Industrial Average Rates in the Midwest and U.S. (in cents).[19]

	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. During 2010-2011, the Commission also approved an economic development rate program for WPL. In addition, any selling of surplus energy to out-of-state utilities has the potential to help lower rates in Wisconsin, as indicated above.

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. Of the 24 electric cooperatives in the state, 11 run their own programs while 13 participate in Focus. Some utilities run voluntary energy efficiency programs within their service territories that provide additional benefits to their customers beyond what Focus offers.[20]

Wisconsin Stat. § 196.374(3) requires the Commission to conduct an extensive review of the Focus program every four years; 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 at the current funding level of approximately $100 million each year,[21] 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.

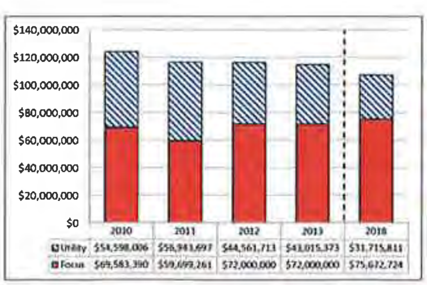
[20] A voluntary energy efficiency program is run by the utility with funding that is above and beyond what the utility is required to collect pursuant to Wisconsin Stat. §196.374 as described above.
[21] Please note that this amount fluctuates based on operating revenue of the IOUs (which are obligated to contribute 1.2 percent of their operating revenue each year). If municipal utilities and cooperatives opt in to the program, they contribute $8 per meter.

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 18, 19, and 20 provide forecasts through 2018 in terms of expenditures and first-year annual energy and demand savings.[22]

Voluntary 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 18: Annual Energy Efficiency Expenditures (2010-2018)[23]



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

Figure 19: First-Year Annual Energy Savings (2010-2018)[20]

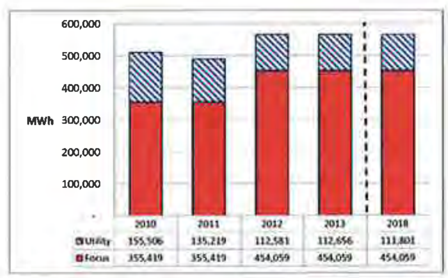
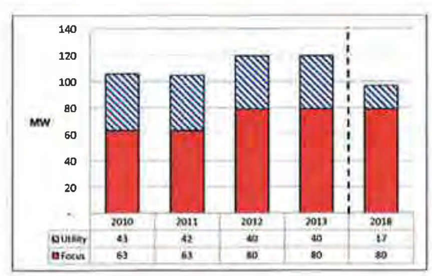


Figure 20: First-Year Annual Demand Savings (2010-2018)[20]



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.

Dynamic rates combined with advanced meters that offer more robust energy use information can yield benefits for electric customers as well. The WPSC pilot programs mentioned above are testing whether information technologies and rates can be used by customers to reduce overall energy use and shift peak use. Informing customers of their energy use can be achieved through various options, such as usage graphs that are occasionally mailed to customers, in-home displays, web portals, smart phone applications, and other notification methods such as email or text. These informational tools can then be used by the customer to take more control of their electricity usage based on their preferences. Several electric utilities in Wisconsin are now experimenting with these information technologies and dynamic rates in order to add value by providing their customers with more service options. However, these technologies often cannot produce savings on their own, as customers must understand and effectively use the information provided to them. Customers must take this information and then install efficiency measures and adopt more energy-conscious behavior in order to reap savings on their bills. Therefore, in order to realize potential benefits for their customers, utilities must discover and implement the right combination of rates and information technologies that are truly effective in adding value to the service they provide.

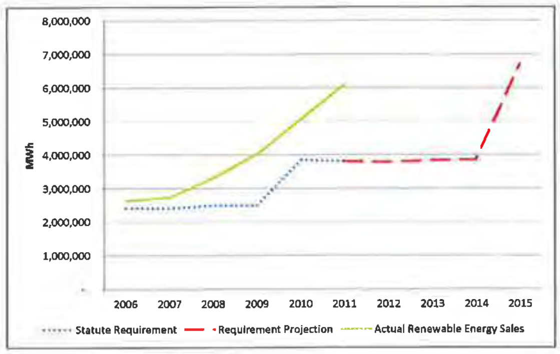
Utilities are also utilizing advanced technologies ("smart grid" technologies) to bolster efficiency and reliability on the supply side. As part of a federally-funded program, three utilities in Wisconsin received grants for smart grid projects that will enhance their distribution and transmission services. 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

A main driver of large-scale renewable resource development for electric generation in Wisconsin is the Renewable Portfolio Standard (RPS).[24] 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 2011, all electric providers have been compliant with their RPS requirements, and have more than doubled statewide total retail sales from renewable resources over the five years from 2006-2011 due to the RPS; from approximately 2.6 million MWh to over 6 million MWh. An average annual growth rate of about 18 percent of retail electric sales from renewable energy occurred during this time. The statewide aggregate of actual renewable retail sales over RPS required sales levels is reflected in Figure 21.

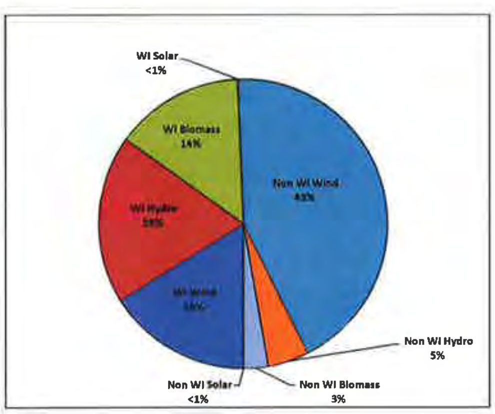
Figure 21: Statewide RPS Renewable Retail Sales (Actual vs. Required, 2006-2015)[25]



[24] Wis. Stat. § 196.378(2)
[25] Source: Commission Staff RPS Compliance Memo

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. Wind is the primary renewable resource used by Wisconsin electric providers, generating 59 percent of renewable electric retail sales in 2011.[26] Although hydroelectric generation makes up approximately 24 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. 49.4 percent of renewable resources are from facilities located in Wisconsin. Figure 22 breaks down 2011 electric sales from renewable resources by type and location. Figure 23 represents growth in sales from wind, hydro, and biomass from 2009 to 2011, and Figure 24 represents growth from solar photovoltaic (PV) sales.[27]

Figure 22: 2011 Renewable Sales by Resource and Location – Percent of Total Renewable Sales[22]



[26] According to the Commission's Electric Provider Renewable Portfolio Standard Compliance report for 2011, 16 percent of Wisconsin's renewable energy came from Wisconsin wind, and 43 percent of Wisconsin's renewable energy came from out of state wind (docket 5-GF-214).
[27] 2009 sales data do not contain all sales from utility voluntary green pricing programs.

Figure 23: Wisconsin Utility Retail Sales by Renewable Resource (2009-2011)[22]

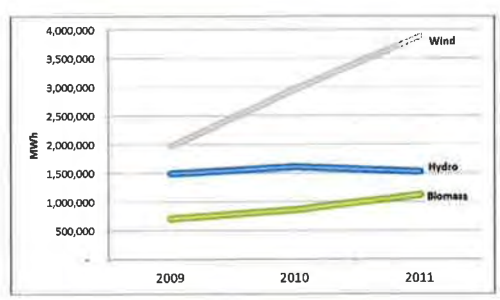
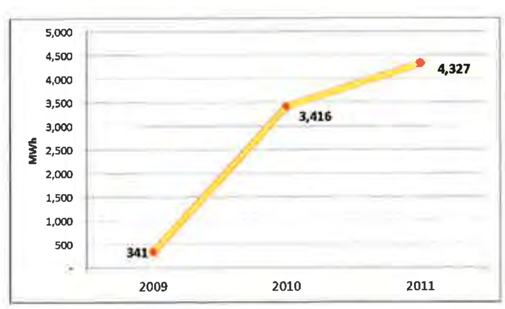


Figure 24: Wisconsin Utility Retail Sales from Solar Photovoltaic (2009-2011)[22]

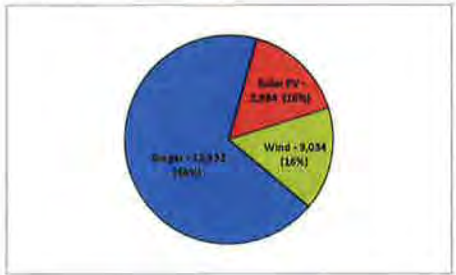


Whereas 2005 Wisconsin Act 141 only allowed hydroelectric generation from facilities under 60 MW in capacity to count as a renewable resource, 2011 Wisconsin Act 34 allows new, large hydroelectric facilities to also count towards RPS requirements starting in 2016. This will likely lead to hydroelectric 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, based on their responses to the 2011 RPS Compliance Report (docket 5-GF-214).

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 2011, over 450,000 MWh of renewable energy was sold to Wisconsin retail customers statewide because of these programs, which moved the renewable proportion of total electric sales to retail customers from 8.88 percent to 9.54 percent.

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 25 represents 2011 capacity of distributed generation supported by Wisconsin utility ARTs.

Figure 25: 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. 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.

LOOKING FORWARD

The Commission received many insightful comments from the public and other interested stakeholders regarding the 2018 SEA. This chapter highlights major issues that were identified in the public comment process, discusses main topics from different perspectives, and provides some relevant historical context. The major topics covered in this section include: 1) Ability of natural gas pipeline capacity to offer sufficient throughput associated with increased gas fired generation, 2) Issues associated with MISO and PJM abilities to increase the free flow of energy and capacity between both RTOs, 3) Increased retail rates in Wisconsin that could lead to a reexamination of the current regulatory model in Wisconsin, and 4) Cost allocation issues associated with planned transmission projects within MISO.

Potential for increased reliance on natural gas-fired electric generation and implications for pipeline use

The Industrial Customer Group (ICG) and WPPI Energy (WPPI) raised the issue of increased reliance on natural gas-fired electric generation. They point out that due to stricter emissions controls from EPA on aging coal plants, in addition to more competitive natural gas prices, many new generation plants are likely to be natural gas fired. This will place increased reliance on the nation's gas pipeline system, but the extent or the level of stress is not fully understood. Several organizations, including MISO, are studying this issue, and the Commission has been involved and continues to monitor MISO's actions and developments. FERC has also shown interest in this subject and currently has a number of proceedings that the Commission is also monitoring. Presently, FERC is examining coordination between natural gas and electric markets in docket AD12-12-000. OMS has submitted comments to FERC, and the Wisconsin Commission is a signatory. OMS comments essentially commended FERC for examining this issue in a timely fashion, and suggested some basic market definition improvements are necessary. OMS and the Commission participated in a federal regional technical conference held in Saint Louis on August 6, 2012.

It should be noted that the Commission has no jurisdiction over interstate pipelines, as FERC regulates their construction and siting. For intrastate projects, the Commission does have some jurisdiction. The Commission concurs with ICG and WPPI that developments in this area must be monitored to avoid shortages when gas demand is traditionally high during the cold of winter, and when electric demand is highest during hot summer days. The Commission currently awaits FERC's ruling in Docket AD12-12-000.

Issues that prevent the free flow of low cost energy and capacity between RTOs

During the past two years, the market monitors for both MISO and PJM have described economic inefficiencies that exist in their respective markets. MISO also conducted a study that suggests that there may be additional ability to transfer electric energy and capacity between MISO and PJM. As a result, MISO and PJM have re-instated a study of these issues under the Joint and Common Market Initiative. FERC is also commencing an investigation, partly in response to letters from the Wisconsin Commission and Public Utilities Commission of Ohio, to examine capacity deliverability across the

MISO/PJM seam, Docket AD12-16-000. FERC received comments on August 10, 2012 and reply comments August 27, 2012.

The Commission has been at the forefront of this investigation and believes existing inefficiencies can be reduced and ultimately deliver ratepayer savings to customers in both MISO and PJM markets. To that end, the Chairperson of the Commission has commenced a states'-led effort to assist MISO and PJM deal with the difficult issues of improving economic efficiency of energy transfers between MISO and PJM. Since the FERC comments phase concluded, both MISO and PJM have held stakeholder issue scoping sessions. Chairperson Montgomery has also been working with Michigan Commissioner White on a study involving both PJM and MISO modelers on an estimation of the transfer capability between MISO and PJM, in either direction. OMS has also become part of the process by forming a States' Seams Working Group that is led by Chairperson Montgomery.

The above efforts involve economic, engineering, institutional, political, and legal challenges. The Commission believes that with FERC's involvement, a more market-driven process can be set up between MISO and PJM that encourages more trading of electric energy and capacity in an efficient manner such that ratepayers and customers in both RTOs can benefit.

Addressing Wisconsin's Electricity Rates

On this subject, there were many comments suggesting ways to address Wisconsin's electricity rates. Two stakeholder groups, Citizen's Utility Board (CUB) and Clean Wisconsin, suggested the SEA take on more of an integrated resource planning (IRP) framework, asserting states have lower rates than those states that do not perform IRP. Two other groups, COMPETE and Retail Energy Supply Association (RESA), suggested that Wisconsin policy makers adopt more of a retail competitive paradigm to improve the rate situation in Wisconsin. These groups assert that over the past decade retail choice states have had better success at rate control, including decreases, than states using the traditional regulated vertically integrated utility model. The ICG also expressed concern over rates adversely affecting the competitiveness of Wisconsin's industries.

Some history regarding Wisconsin's consideration of retail choice is important. In the middle-late 1990s Wisconsin did examine the use of retail choice, where customers get to pick their generation supplier. At the time, Wisconsin was experiencing supply adequacy and reliability issues in the electric energy area. The Governor, Legislature, and the Commission determined that addressing reliability and supply adequacy was paramount. To that end, the legislature passed several new laws, including the one creating the SEA that essentially placed emphasis on the utilities to upgrade and build new necessary transmission and electric generation infrastructure. As this SEA points out, and several commenters have noted, there has been success in that regard. Wisconsin presently has successfully addressed reliability and supply adequacy issues.

The Commission continues to be concerned about rates, and as one of the ways to help address the issue, the Commission has, through rate proceedings, adopted innovative rate structures, including economic development rates. The Commission has also approved rate tariffs that are market oriented, whereby certain classes of customers can take energy at real time wholesale energy prices. Numerous customers have signed up for this tariff, which to some extent mimics rate approaches that occur in retail choice states. For example, the state's largest electric utility WEPCO has in place contract service rates, a real-time market pricing rider, and two experimental market incentives tariffs. Furthermore, the Commission in all of its rate proceedings has indicated and continues to encourage ratepayers and utilities to come forth with innovative rate designs.[28]

With respect to retail choice, the legislature rejected such an approach in the late 1990s after extensive study suggested that given Wisconsin's geographic position and low electric rates at the time, opening up the state to retail competition under a variety of circumstances could have led to higher rates. Stakeholders and the public at the time were also more interested in maintaining electric reliability.

CUB and Clean Wisconsin suggest that the SEA take on a new direction of using a modern IRP approach that examines the big picture electric landscape more "holistically." This new suggested approach is not a prescriptive one like the Advanced Plan which had been used from 1975-1998. The new IRP approach suggested by CUB and Clean Wisconsin would transform the SEA and take this form:

1. Madison Gas & Electric Company (MGE), Wisconsin Electric Power Company (WEPCO), Wisconsin Power and Light Company (WPL) and Wisconsin Public Service Corporation (WPS) would each file individual integrated resource plans with the Commission every two years.
2. The purpose of the process would be to identify a future portfolio of resources that offers the best combination of cost and risk, taking into account factors such as environmental impacts, fuel supply availability, price volatility, resource diversity, and the ability of available resources to reliably meet demand.
3. The process would be separate for each utility and would be on staggered schedules so that commissioners, Commission staff, and intervenors could participate in each process at a reasonable pace. It would not be a contested case process and would be facilitated in the early stages by a series of monthly public meetings between stakeholders and the utility.
4. At the monthly meetings, participants would offer input as to the content of the plan (including whether any particularly pressing issues should be brought to the forefront) and would identify the range of modeling inputs to be used in the planning model.

[28] In the present rate case involving WEPCO, the record indicates that retail residential customers in the WEPCO service territory would pay $0.14/kWh. In the service territory adjacent to WEPCO's in Illinois, a retail choice state, the default fall back tariff for a residential customer taking service from Exelon's CommonWealth Edison is $0.148/kWh. If a customer can find a retail choice provider that offers a better rate, such a customer can choose that alternative supplier. (See Docket 05-UR-106, Commission's First Data Request, Electronic Reference Number 164746, filed April 27, 2012.) This example is not meant to say that retail choice is poor public policy, but rather is used as a demonstration to show that comparisons of rates among states and utilities always need to reflect the context that each state finds itself in. In the case of Wisconsin, the state is coming off of an aggressive construction program that has successfully addressed supply and reliability issues, so one would expect at the outset that rates would be higher now, but over time, with plant depreciation and as other states address reliability and adequacy issues, simple rate comparisons could change dramatically.

5. Following these meetings, the utility would perform the modeling and draft an IRP. Each utility's written plan would show future long-term (20 years) resource needs, its analysis of the expected costs and associated risks of the alternatives to meet those needs, and its near-term four-year action plan to select the best portfolio of resources to meet those needs. The draft would then be distributed to parties informally for technical edits (e.g., typos, errors in reporting of figures) and would then be formally filed with the Commission for more substantive comments.
6. Once the draft is filed at the Commission, technical workshops would be held at the Commission to discuss substantive issues with the draft (e.g., if certain stakeholders believed the utility failed to properly take into account certain items).
7. Written initial and reply comments would then be filed with the Commission on any remaining issues.
8. The Commission would then consider comments and recommendations on a utility's plan at an open meeting before issuing an order "acknowledging" or "not acknowledging" each aspect of the utility's proposed four-year action plan. An "acknowledgement" is an assessment that the action item is reasonable at the time, but it is not a final, binding determination and does not equate to pre-approval. The Commission would provide the utility an opportunity to revise the IRP before issuing an acknowledgment order. The Commission would also provide direction to a utility regarding any additional analyses or actions that should be undertaken in its next IRP.
9. The utility would then issue the final IRP and submit an annual update that describes what steps the utility has taken to implement the action plan, and that assesses what has changed since the acknowledgement order.

CUB and Clean Wisconsin IRP method is one that requires careful scrutiny by stakeholders and the Commission. Whether such an approach could be adopted by the Commission would likely require legislative or rule making changes to the SEA or other statutes. As can be seen, the CUB and Clean Wisconsin proposal takes a much different direction toward electric energy policy than the proposals put forth by COMPETE and RESA. The thematic approaches suggested by these stakeholders are duly noted by the Commission, and in the coming year the Commission will examine the appropriate role or changes to the SEA, if necessary, and will also continue its dialogue with both the Executive and Legislative branches.

Recent developments in transmission cost sharing

The Industrial Customer Group (ICG) indicated that more attention should be placed on transmission costs. Although transmission costs are less than 10 percent of the retail rate paid for electricity, the category of costs associated with transmission has been on a steady increase since 2002, when the Arrowhead-Weston project was approved. To date, transmission construction in Wisconsin has been primarily for reliability reasons.

MISO identifies essentially three categories of major transmission lines. For simplicity, a threshold voltage of 345kV and above is used here. The three categories are MVP or Multi-Value Projects, MEP or Market Efficiency Projects, and BRP or Baseline Reliability Projects.

MVP lines are generally associated with meeting governmental mandates or policy choices. The many states that passed RPS laws requiring the use of wind energy has led to the need to construct new transmission lines to move clean renewable power and energy located in Minnesota, Iowa, and the Dakotas to load centers. Current cost allocation policy as set by FERC has load paying 100 percent for these lines. Some states have balked at that cost allocation approach, and have sued in federal court, where a ruling is expected sometime in 2013. These states believe that generators benefitting by the construction of the MVP line should shoulder some of the cost burden. The Commission has also intervened in that federal court case on additional issues related to MVP construction. The cost impacts under the present FERC mandated cost allocation method and what the federal courts may require is not known, so no numerical analysis is currently available. If generation were to pay more for the MVPs, certain states may pay less than under the FERC tariff approach, but identifying clear winners and losers in terms of costs has not been attempted. This issue has played out more in terms of legal merits. As identified elsewhere in the SEA, two large scale MVPs could affect Wisconsin. These are potential lines approximately from La Crosse to Madison, and another from Madison to Dubuque, Iowa.

MEP transmission lines facilitate the economic exchange of energy, generally moving electricity from low cost areas to higher cost load areas in the MISO footprint. MEP lines have about 20 percent of their cost shared with all utilities in the MISO footprint, and 80 percent of the cost remains with the local transmission companies that receive the greatest benefit as measured by changes in electric energy production costs. In recent history, the Commission approved the construction of a 345kV line from the Madison area near Rockdale, Wisconsin to the Paddock transformer located near Beloit. This project is now in operation, and it brings lower cost energy from the southern part of MISO's footprint into Wisconsin, so that ratepayers in the state receive lower costs for their electric energy.

High voltage BRPs under current federal tariff receive the following rate treatment: 80 percent of the transmission cost is paid by the local utilities benefiting by the improved reliability, with the other 20 percent of costs spread to all the utilities in MISO. Presently, the largest BRP undergoing construction in Wisconsin is the Rockdale-West Middleton project, in the Madison area.

MISO has indicated that going forward the cost-allocation treatment for BRPs is likely to change, whereby the local utilities pay for all of the reliability upgrade. MISO is planning to eliminate the 20 percent cost sharing with other utilities component due to changes in federal policy, specifically Order 1000 and Order 1000A identified elsewhere in the SEA.

The exact ratepayer impact of the MVP build out and the change in cost-allocation treatment for BRPs is not known at this time. Based on $5 billion in new transmission lines was recommended by MISO as part of the MVP portfolio. A rough estimate of the impact on Wisconsin ratepayers when the whole MVP

portfolio is constructed is approximately $150 million per year.[29] As for changes in the pending BRP cost allocation policy, the Commission has requested MISO to perform such calculations, and results should be forthcoming. MISO filed its BRP policy change on October 25, 2012. New transmission costs are recovered in customer rates via tariff charges by the transmission providers. These charges are approved by FERC and not the Commission.

[29] This $150 million annual estimate is calculated as follows: $5 billion in new MISO MVP transmission lines once all completed and in operation would need to be recovered using a fixed charge rate that encompasses capital cost, return on capital and depreciation. The approximate value for all MISO utilities is around 20 percent, meaning about $1 billion would be required of all ratepayers in the MISO footprint, or 0.20 times $5 billion = $1 billion. Wisconsin retail load is presently about 15 percent of the load in the MISO footprint, so the $1 billion would need to be adjusted for Wisconsin ratepayers using this 15 percent value. This would translate into an annual value of about $150 million Wisconsin ratepayers would have to pay once all the MVPs are built and constructed and in operation in MISO. This is a very rough estimate using a simplified algorithm for presentation purposes here; the actual value will depend on which MVP projects actually get finished and in what time frame and order. The simplified estimate here is meant to provide a sense of scale and not provide an exact amount that would be recovered in rate cases. To put the $150 million into context, the U.S. EIA shows that the total annual retail rate collection to be approximately $6.7 billion.

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]	5	Solar Facility	To be determined	WEPCO	Solar	To be determined	Cost recovery requested as part of 5-UR-106
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	Approved 6680-EB-105
2014	Non-dispatchable[1]	5	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)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]									
[illegible]	Application Pending	[illegible]	[illegible]	Monroe	[illegible]	[illegible]	[illegible]	[illegible]	New switching station
[illegible]	[illegible]	Two new 2 mile 138 kV lines	96th Street - Milwaukee County	Milwaukee	[illegible]	[illegible]	[illegible]	[illegible]	New Substation
[illegible]	Application Expected [illegible]	New 120 mile 345 kV line	[illegible]	[illegible]	345	450-500	[illegible]	[illegible]	
[illegible]	[illegible]	[illegible]	[illegible]	Manitowoc, Sheboygan	[illegible]	[illegible]	Feb-[illegible]	Oct-[illegible]	Two new substations [illegible] termination at [illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	Line termination at Cardinal [illegible]
[illegible]	[illegible]	Rebuild 49 miles of 138 kV line	[illegible]	Waukesha, Jefferson, Dodge, Washington	[illegible]	[illegible]	2014	[illegible]	
[illegible]	[illegible]	New 115 mile 345 kV line and 100 miles of 138 kV line[4]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	25 miles new 138 kV, rebuild [illegible]	[illegible]	Kenosha, Walworth	138	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]									
[illegible]		Rebuild 20.8 mile 161 kV line	Genoa - La Crosse	La Crosse, Vernon	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]		Rebuild 49.4 mile 161 kV line	Alma - La Crosse to Marshland	Buffalo, La Crosse, [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]		New 0.5 mile 161 kV line	[illegible] - DPC [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	New 138 kV sub at [illegible]
[illegible]									
[illegible]	Application Pending	[illegible]	Stone Lake - [illegible]	Sawyer	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	Application Expected [illegible]	[illegible]	Osprey - [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	Application Pending	[illegible]	[illegible]	Rusk, Sawyer	[illegible]	[illegible]	Dec-17	Dec-18	New substation [illegible]
No Docket		[illegible]	Iron River - Bay Front	Ashland, Bayfield	[illegible]	[illegible]	[illegible]	[illegible]	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] From www atcllc com
[5] Partly addressed by route approved for CapX project (05 CE-136)
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)
2012	Intermediate	58	Alma 1, 2, 3	DPC	Coal	Alma
2013	Peaking	28.5	Blount Street 5	MG&E	Gas, Coal	Madison
2013	Peaking	27.4	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
MATS	Mercury and Air Toxics Standard
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.