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June 30, 2016

VIA E-Filing

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101-2147

RE: In the Matter of the Missouri River Energy Services 2017-2031 Integrated Resource Plan
Docket No. ET10/RP-16-509

Dear Mr. Wolf:

Missouri Basin Municipal Power Agency d/b/a Missouri River Energy Services (MRES) is pleased to submit its 2017-2031 Integrated Resource Plan to the Minnesota Public Utilities Commission ("Commission") for acceptance for filing. This Resource Plan is filed in compliance with the Commission's order in our previous resource plan proceeding, Docket No. ET10/RP-10-735, as well as Minnesota Statutes § 216B.2422 and Minnesota Rules Chapter 7843, and related requirements.

This Resource Plan forecasts a very moderate rate of growth in the needs of MRES Members, and identifies the most reliable, cost-effective, and environmentally sensitive manner for MRES to meet its obligations to supply its Members with the power necessary for the vitality of their communities. For the first time, MRES has conducted separate analyses based on the fact that its Members are now located in separate Regional Transmission Organizations.

Over the study period, the Resource Plan identified a surplus of resources in SPP and a deficit of resources in MISO, due to the fact that generating resources in SPP can no longer serve MISO load. The capacity needs in both MISO and SPP can be met primarily with demand-side management and conservation, and renewable resources. In MISO, however, additional low-carbon capacity will be needed to serve load previously supplied from resources in SPP.

Certain portions of the Resource Plan, and the entirety of Appendix J contain trade secret information and are marked as such, pursuant to the Commission's Revised Procedures for Handling Trade Secret and Privileged Data, which implement the intent of state law. *See* Minn. Stat. § 13.37 and Minn. R. 7829.0500. A statement providing the justification for designating and excising the Trade Secret Data follows this letter.

As reflected in the enclosed Affidavit of Service, both the Public version and the Non-Public version of this this Resource Plan are filed electronically via eDockets. All parties on the enclosed service list will be served electronically (unless otherwise indicated) with the Public version of the Resource Plan and accompanying information.

In addition, please note that the Adobe® *.pdf electronic documents of the Public and Trade Secret versions each have a navigation pane which allows the reader to view the Table of Contents on the left menu bar. By clicking on an entry in the Table of Contents navigation pane, the reader will automatically see that page appear on their screen. For large documents such as this, we find that it provides a more user-friendly experience for people reviewing the document in detail.

Finally, courtesy copies of the Trade Secret version – in physical form –will be delivered to staff of the Commission (1 copy) and the Department of Commerce, Division of Energy Resources (3 copies), as they have previously requested.

Should you have any questions regarding this filing or the trade secret designation, please do not hesitate to contact me at 605-330-6951 or mrg.simon@mrenergy.com.

Sincerely,

/s/ Mrg Simon

Mrg Simon, Director
Legal

Enc.
Cc: Service List

Statement Regarding Designation and Excision of Trade Secret and Privileged Information by Missouri River Energy Services

Pursuant to the Revised Procedures for Handling Trade Secret and Privileged Data, dated September 1, 1999, the Commission and Department are the Responsible Authority Designees of information filed with the Commission. State law addresses the treatment of trade secret or privileged information filed with a public body under the Minnesota Government Data Practices Act. Minn. Stat. §13.37; Minn. Rule 7829.0500. In particular, trade secret or privileged information must be specifically and clearly identified in Trade Secret versions of such documents and excised from Public versions of those same documents. In instances where all or a substantial portion of the data in a document is excised, a statement must be provided that describes "the nature of the excised material, its authors, its import, and the date on which it was prepared." Minn. R. 7829.0500, subpt. 3 (1997).

Missouri River Energy Services (MRES) requests the Commission and Department accept its Trade Secret Integrated Resource Plan and its Public version Integrated Resource Plan, together with associated appendices, for filing, pursuant to Minn. Stat. §216B.2422 and Minn. Rules Chapter 7843. MRES has designated portions of its 2017-2031 Resource Plan as containing Trade Secret Data or containing both Trade Secret and Privileged Data. MRES has used both the bracket language suggested by the rule, and yellow highlighting to indicate such information. The purpose of such actions is to prevent disclosure of information regarding the formulas, compilations, programs, methods, techniques, process, and proprietary data inputs that MRES employs in identifying, obtaining, managing, and comparing various resources and managing its risks.

The designated trade secret information in the Integrated Resource Plan itself was obtained by commissioning several consulting firms to provide specific types of data not readily available. Some of the data was commissioned and prepared for purposes of studying specific resource options and technology, and some of it was commissioned and prepared specifically for the analysis in the Integrated Resource Plan. The information was obtained from 2013 through 2014. The information is proprietary to each of those firms.

In addition, the entirety of Appendix J, "MRES Environmental Matrix," contains both trade secret data and data that is subject to the long-standing privilege accorded to attorney work product. It not only identifies existing and potential environmental laws and regulatory rules, it also contains analysis specific to existing MRES resources, future decisions regarding those resources, and matters of actual and potential litigation specific to such resources. This document is an active strategic reference tool that is prepared exclusively by the lawyers of the MRES Legal Department.

Collectively, this designated information has independent economic value, both actual and potential, from not being generally known to or accessible by the public, competitors, and suppliers, who might otherwise gain a commercial advantage over MRES if the information were made public. MRES treats this information as confidential, and manages the information pursuant to its information governance and security policies and procedures. If the information were to be publicly available, it would jeopardize the ability of MRES and its Member municipal electric utilities in Minnesota, as well as those in Iowa, North Dakota and South Dakota, to provide reliable, cost-effective energy and energy services in a fiscally responsible and environmentally sensitive manner to retail consumers throughout the region.

In the event of a challenge to the designation of Trade Secret or Privileged data, MRES respectfully requests the opportunity to provide additional justification regarding the basis for nonpublic treatment of this information.

/s/ Mrg Simon

Director, MRES Legal Department
Attorney at Law

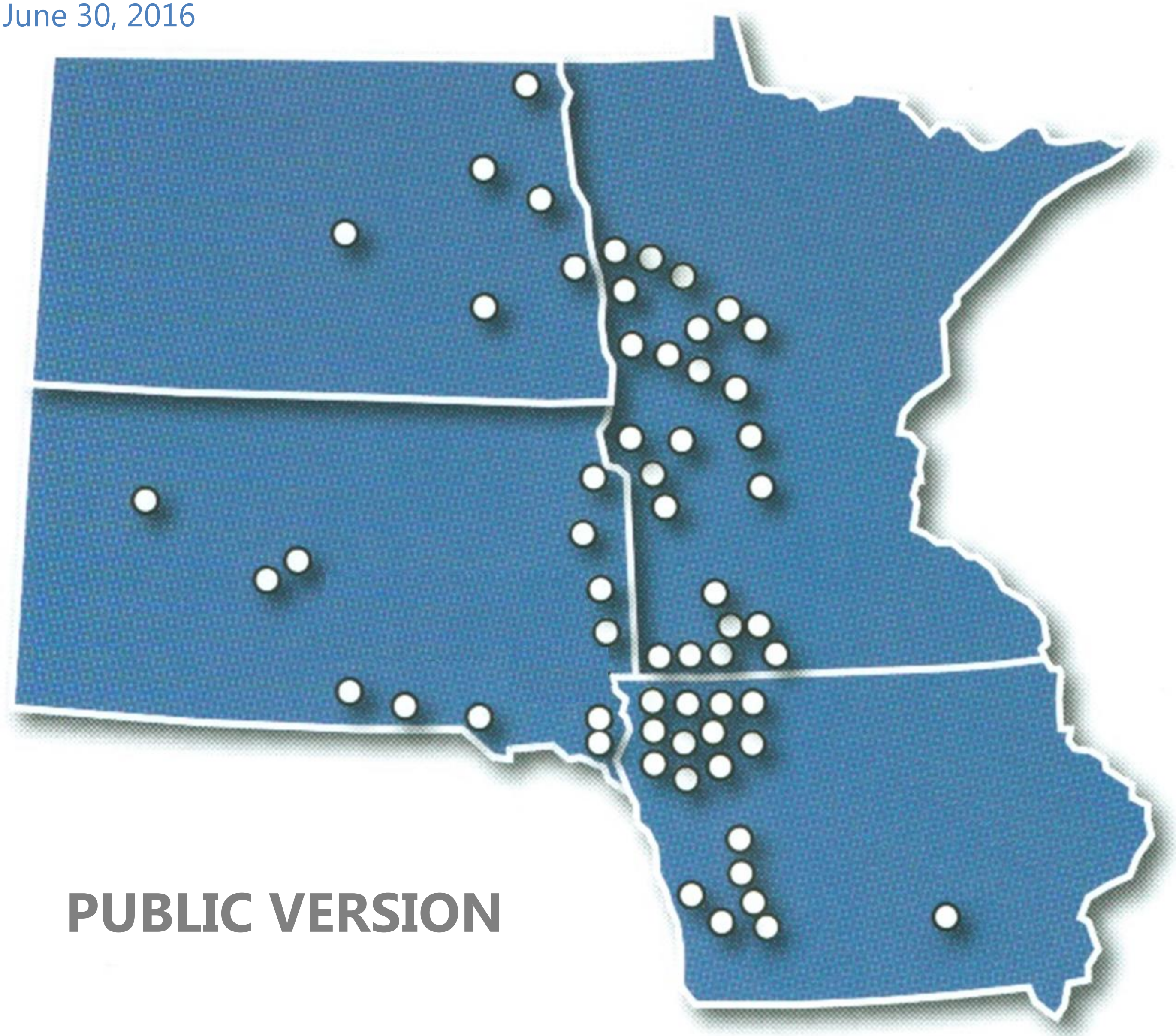
2017-2031 Integrated Resource Plan

Submitted to the

Minnesota Public Utilities Commission

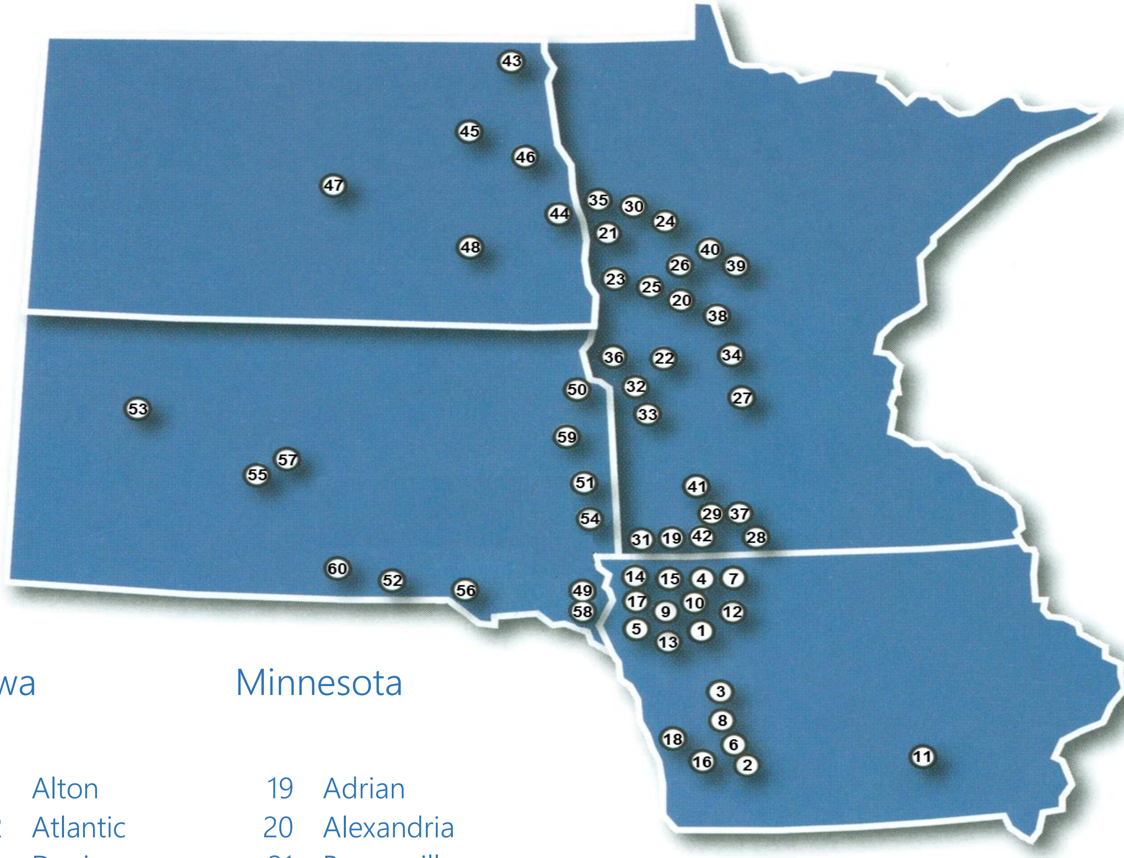
Docket No. ET10/RP-16-509

June 30, 2016



PUBLIC VERSION

MISSOURI RIVER ENERGY SERVICES MEMBERS



Iowa

1 Alton
2 Atlantic
3 Denison
4 Hartley
5 Hawarden
6 Kimballton
7 Lake Park
8 Manilla
9 Orange City
10 Paullina
11 Pella
12 Primghar
13 Remsen
14 Rock Rapids
15 Sanborn
16 Shelby
17 Sioux Center
18 Woodbine

Minnesota

19 Adrian
20 Alexandria
21 Barnesville
22 Benson
23 Breckenridge
24 Detroit Lakes
25 Elbow Lake
26 Henning
27 Hutchinson
28 Jackson
29 Lake Park
30 Lakefield
31 Luverne
32 Madison
33 Marshall
34 Melrose
35 Moorhead
36 Ortonville
37 Sauk Centre
38 Saint James
39 Staples
40 Wadena
41 Westbrook
42 Worthington

North Dakota

43 Cavalier
44 Hillsboro
45 Lakota
46 Northwood
47 Riverdale
48 Valley City

South Dakota

49 Beresford
50 Big Stone City
51 Brookings
52 Burke
53 Faith
54 Flandreau
55 Fort Pierre
56 Pickstown
57 Pierre
58 Vermillion
59 Watertown
60 Winner

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Lists of Figures, Graphs, and Tables

List of Acronyms

AMI	Advanced Metering Infrastructure
BART	Best Available Retrofit Technology
BES	Bright Energy Solutions®
CAA	Clean Air Act
C-BED	Community-Based Energy Development
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDR	Coordinated Demand Response
CHP	Combined Heat and Power
CIP	Conservation Improvement Program
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPP	Clean Power Plan
CT	Combustion Turbine
DOE	Department of Energy
DSM	Demand-Side Management
EGU	Electric Generating Unit
EIA	Energy Information Administration
EM&V	Evaluation, Measurement, and Verification
EPA	Environmental Protection Agency
EVA	Energy Ventures Analysis, Inc.
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
GRE	Great River Energy
GWh	Gigawatt hour
HVAC	Heating, Ventilating, and Air Conditioning
ICAP	Installed Capability
IRP	Integrated Resource Plan
kW	kilowatt
kWh	kilowatt hour
LRS	Laramie River Station
MBPP	Missouri Basin Power Project
MISO	Midwest Independent Transmission System Operator
MMBtu	Million British Thermal Units
MRES	Missouri River Energy Services
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NOx	Nitrogen Oxides
Pb	Lead
PHEV	Plug-in Hybrid Electric Vehicle
PM_{10}	Particulates up to 10 microns
$PM_{2.5}$	Particulates up to 2.5 microns
PRC	Planning Resource Credit
PRM	Planning Reserve Margin
RAR	Resource Adequacy Requirement
RECB	Regional Expansion Criteria and Benefits
RES	Renewable Energy Standard
RF	Radio Frequency
RICE	Reciprocating Internal Combustion Engine
RRHP	Red Rock Hydroelectric Project
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
SSM	Startup, Shutdown, Malfunction
UCAP	Unforced Capability
WAPA	Western Area Power Administration
WPP	Watertown Power Plant

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Part I: Introduction

1. Missouri River Energy Services

Missouri Basin Municipal Power Agency, doing business as Missouri River Energy Services (MRES), is a not-for-profit, member-based, joint-action agency that provides power supply, transmission, and related services to its Member municipalities in Iowa, Minnesota, North Dakota, and South Dakota. Fifty-seven of the sixty Members receive power supply under identical long-term "Power Sale Agreement[s] (S-1)" (S-1 Agreement).[1] All MRES S-1 Members purchase power supply from MRES in an amount necessary to entirely supplement the fixed amount of their respective allocations of federal hydroelectricity based on individual long-term contracts between each S-1 Member and the Western Area Power Administration (WAPA). The three remaining Members each have individual and distinct long-term power supply agreements with MRES,[2] and only one of those Members also has an allocation of federal hydropower and a WAPA contract.

MRES is responsible for providing all power supply supplemental to the amounts supplied by WAPA for its S-1 Member municipalities, as well as for providing specifically defined power supply amounts under long-term power sale agreements with its Non S-1 Members. In order to meet these obligations, MRES has contracted for a variety of power supply resources. The largest of the MRES power supply resources are owned by Western Minnesota Municipal Power Agency (Western Minnesota), and are dedicated exclusively to MRES pursuant to a contract. Additional resources have been acquired by MRES pursuant to bi-lateral purchase power agreements with other entities.

MRES is uniquely structured, making it difficult to compare it with most other utilities that file resource plans in Minnesota. MRES has no retail loads and all of its sales are wholesale sales made to its municipal utility Members or to other wholesale utilities. MRES Members (to whom MRES makes wholesale sales) are located in four separate states. All but two MRES Member cities also buy various amounts of power supply from WAPA under separate contracts, and that WAPA power supply is "blended" with the MRES power supply to serve the customer owners in

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[1] "S-1 Members" are the 57 Member cities of MRES that have each executed a "Power Sale Agreement (S-1)" under which MRES has the obligation to provide all the supplemental power needs of those Members, that is, each Member's power supply needs in excess of their allocation of federal hydropower from WAPA.

[2] "Non S-1 Members" are the three member cities of Atlantic and Pella, Iowa, and Hutchinson, Minnesota. Atlantic is the only one of the three that has a WAPA contract and associated hydropower allocation.

each Member community. The power supply cost varies for each city, depending upon several factors including the relative amounts of MRES and WAPA power supply the city purchases, its relative amount of energy and peak demand each month, and the amount of load growth or decline it experiences. Any significant load change in one Member city affects MRES costs, thereby also affecting power supply costs for all Member cities. Each MRES Member community owns and locally controls its electric distribution system. As a result, each Member is responsible for setting its own rates and other terms and conditions of service as a matter of local control, based on the cost variables unique to its own retail distribution system.

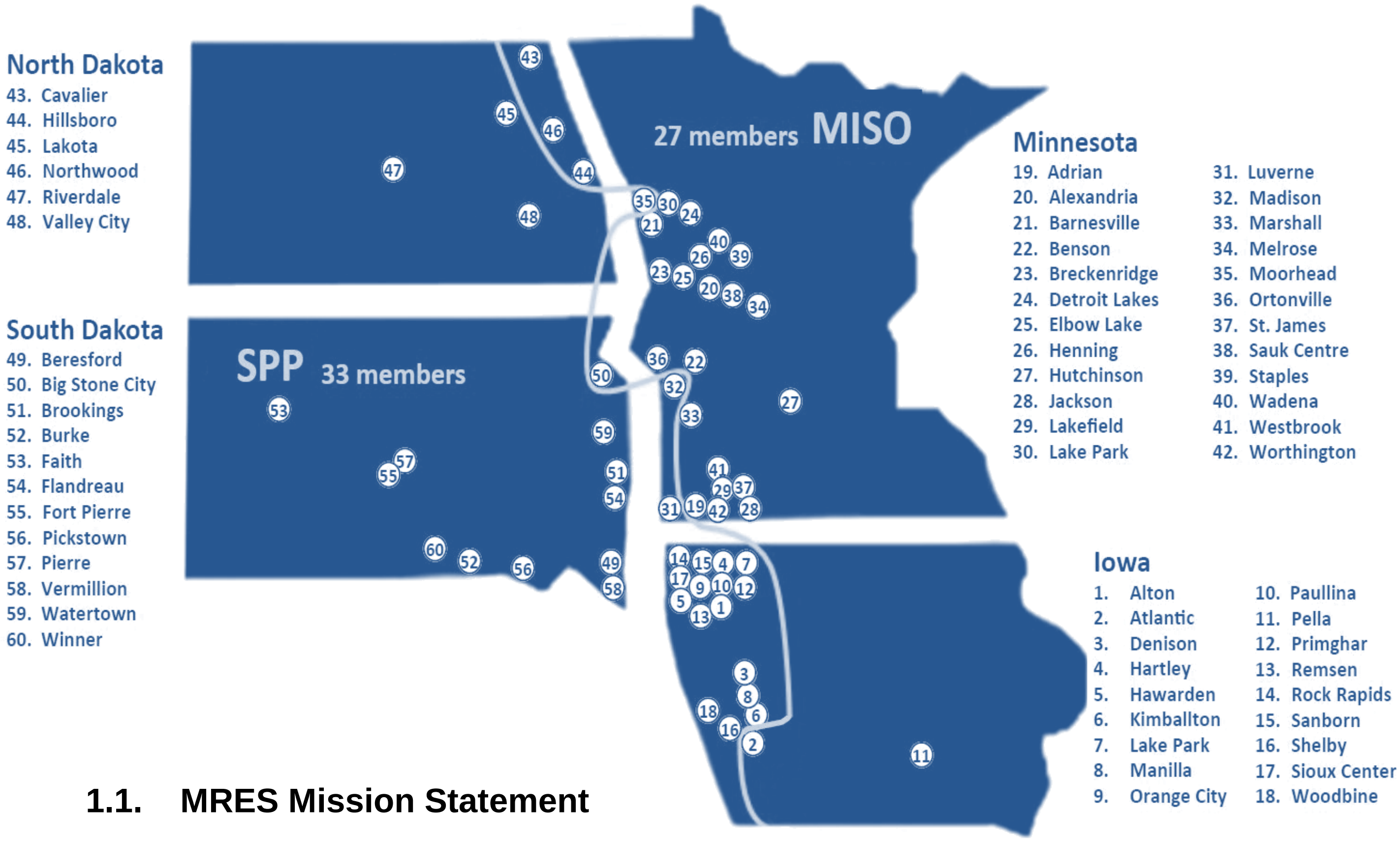
MRES provides power supply only at the wholesale level. MRES has no retail customers, and cannot implement programs to deliver energy services unilaterally with Members' retail customers. Instead, MRES focuses its efforts on assisting Member municipalities with their energy efficiency, conservation, and other Demand-Side Management (DSM) programs by providing incentives and developing joint programs with Members. In turn, each Member city is responsible for assessing the appropriate amounts of load control and energy efficiency programs to pursue and implement within its community. In addition, Minnesota Members also are responsible for meeting Minnesota's Conservation Improvement Program (CIP) requirements, and Members in other states are responsible for meeting any corresponding requirements applicable to them.

The MRES Resource Plan includes both supply-side resource options implemented by MRES and estimates of the effects of DSM programs put in place by the Members either on their own or as assisted by MRES.

A significant development in 2015 resulted in MRES Member loads now being split between two Regional Transmission Organizations (RTOs), namely the Midcontinent Independent System Operator, Inc. (MISO) and the Southwest Power Pool, Inc. (SPP) market areas. Twenty seven Members, representing about half of the MRES energy sales, are located within the MISO market area. The remaining 33 Members are located within SPP, as of October 1, 2015. In regard to the 24 MRES Members located in Minnesota, three are within SPP, and the remaining 21 are within MISO. Most MRES and WAPA generation resources are within SPP.

The figure on the following page provides a geographic reference for the "split" of the MRES Members between the two RTOs.

Figure 1-1: MRES Members in SPP and MISO



1.1. MRES Mission Statement

Missouri River Energy Services is dedicated to supplying our members with reliable, cost-effective, long-term energy and energy services in a fiscally responsible and environmentally sensitive manner. Missouri River Energy Services is an extension of our members, and through joint action members will remain competitive while enhancing their relationships with their customers.

The mission statement of MRES establishes that the essential purpose of MRES is to ensure Members are served based on the very principles that lie at the heart of integrated resource planning: the goals of adequate and reliable supply, minimizing costs and environmental impacts, and avoiding undue risks to its Members and their ultimate consumer-owners. This document endeavors to carry out these objectives as they relate to resource planning.

1.2. Changes Since the Last Filing

1.2.1. Impact of Changing Environmental Regulations

MRES constantly monitors state and federal environmental matters and developments, particularly those in the areas of air quality and emissions from generating resources, to assess potential impacts to MRES operations and ensure compliance with applicable laws and regulations. MRES takes a comprehensive approach to monitoring statutes and regulations applicable to the various generating facilities within its power supply portfolio, as well as proposed laws, regulations, and judicial decisions that may alter the regulatory regime for existing resources, potential generation portfolio additions, and transmission issues. This section describes efforts by MRES to track and respond to those issues and developments.

The MRES Legal Department partners with the Power Supply and Operations Department to closely monitor regulations affecting MRES resources, whether those emanate from the United States Environmental Protection Agency (EPA), states, or other governing bodies. In addition, MRES retains both outside General Counsel and Special Counsel to both monitor general environmental matters and to collaborate on specific regulatory, legal, and judicial developments at the state and federal level. MRES also belongs to several national trade associations which monitor and advocate on environmental matters relating to power generation, such as the American Public Power Association and the National Hydropower Association.

1.2.2. General Environmental Matters

Air, water, and land quality are all of keen interest to MRES, and the staff manages a wide range of environmental issues regarding the generation and delivery of electricity. MRES regularly monitors air quality topics including those governed by the Clean Air Act (CAA) to reduce carbon dioxide (CO_2) emissions from existing and new power plants, Regional Haze, the Startup, Shutdown, Malfunction (SSM) Rules, the Cross-State Air Pollution Rule formerly the Clean Air Interstate Rule (Transport Rule), Mercury and Air Toxics Standards, rules relating to the operation of Reciprocating Internal Combustion Engines (RICE Rules), the rules and revisions to Ozone Standards, regulations relating to Particulate Matter ($PM_{2.5}$), and other such matters.

Equally important, MRES also actively follows developments relating to surface and ground water, including those related to the National Pollutant Discharge and Elimination System for both the nationwide and individual permit processes administered by states, recent updates under Clean Water Act Section 3l6(b) for cooling water intake structures (impingement/ entrainment), coal combustion residual (CCR) (also known as coal ash) regulations, and other substantive environmental issues. The final rules on the Waters of the United States developed by the EPA and the United States Army Corps of Engineers promise to impact both land use as well as water quality matters, and MRES is following the litigation in the various federal district courts and circuit courts of appeals relating to this rule. MRES also closely monitors litigation challenging any of these measures, as well as the remands and subsequent rulemakings (if any) that might result.

As a transmission-owning member of MISO and SPP, MRES also participates in regulatory matters governed by the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), the Midwest Reliability Organization, Electricity Information Sharing & Analysis Center, and other national and regional entities. Actions of these organizations could potentially directly or indirectly impact environmental issues, and MRES utilizes both staff and consultants to monitor and participate in these organizations.

One of the tools MRES has developed to monitor the most significant environmental regulations and developments affecting those regulations is a proprietary document referred to as the MRES Environmental Matrix. The Environmental Matrix tracks laws, regulations, proposed regulations, and litigation concerning environmental matters. In addition, it identifies which Western Minnesota resources are subject to each such regulation and the potential effect of the regulation and/or response to maintain compliance, as well as the cost of compliance (where known). A copy of the MRES Environmental Matrix is included as Appendix J.

1.2.3. Regional Haze Litigation

Since the previous resource plan and updates were filed, there have been significant developments related to the application of the Regional Haze rules under the CAA as they apply specifically to Laramie River Station (LRS), the only coal-fired generating resource in the MRES portfolio. These developments will have a significant impact on the physical operations, and both the capital and operating expenses of LRS.

The Regional Haze provisions of the CAA require facilities that began construction between 1962 and 1977, which includes LRS, to identify and apply Best Available Retrofit Technology (BART) to control sulfur dioxide and NOx if their emission rates for those pollutants exceed a certain designated level. LRS has installed over-fire air technology, and low-NOx burners for all three units to address these BART requirements.

On January 23, 2014, EPA partially disapproved that portion of the Wyoming State Implementation Plan (SIP) for NOx removal, and issued its own final rule imposing a Federal Implementation Plan (FIP) with more stringent emission limits, which imposes a more restrictive emission limit on the operation of LRS. Specifically, the FIP a) imposes NOx emissions limits 0.07 pounds per MMBtu (30 day rolling average); b) applies to all three units; and c) requires the installation of Selective Catalytic Reduction (SCR) technology, in addition to the previously installed low-NOx burners and over-fire air. The difference in visibility improvement for the FIP's SCRs versus the Selective Non-Catalytic Reduction (SNCR) technology called for in the SIP adopted by Wyoming is less than one deciview (a deciview is the lowest measurable increment perceptible by the human eye). However, the cost difference to install three SCRs as opposed to three SNCRs is greater than $500 million for the entire project.

Under the FIP, the owners of LRS[3] are required to install SCR equipment on LRS Units 1, 2 and 3 by March 4, 2019. Basin Electric, as Operating Agent of LRS and on behalf of all the owners, appealed this decision to the United States Court of Appeals for the Tenth Circuit.[4] The State of Wyoming, PacifiCorp, and Powder River Basin Resource Council also appealed the FIP.[5] On September 9, 2014, the Tenth Circuit granted a stay of enforcement pending appeal, extending the deadline for compliance with the FIP for the duration of the stay for LRS (and other utility units that are the subject of the appeal). The appeal is ongoing, and oral arguments are expected to occur later this year. It is unknown when the Tenth Circuit will consider the cases, or the ultimate outcome when a decision is finally issued.

The estimated cost to Western Minnesota for its share of the expense of installing SCRs on all three units is $125 million, compared to $17 million for the alternative SNCRs that were required by Wyoming's SIP. The MBPP is actively evaluating SCR technology necessary for compliance with the final rule, and is moving forward to install SCR technology on Unit 1. The installation of a single SCR requires not only a major capital investment, but it also imposes a significant parasitic load that will reduce the net output of the unit, and require that the unit is taken out of service for a substantial period of time.

1.2.4. Emerging Carbon Dioxide regulations

EPA's New Source Performance Standards for CO_2 mandate reductions of CO_2 emissions from existing and new power plants, and will significantly impact LRS, and thus MRES and its Member municipal utilities. The federal emission guidelines of the rule establish a detailed framework according to which each state must adopt enforceable

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[3] The Missouri Basin Power Project (MBPP) consists of Laramie River Station and associated facilities, and is owned by six consumer-owned electric utilities. The MBPP participants include Western Minnesota, which owns a 16.47% share of MBPP (as tenants in common). Western Minnesota sells its entitlement to capacity, energy, and transmission and MRES purchases all of its resources pursuant to an exclusive contract between the parties.

[4] *Basin Electric Power Coop. v. EPA*, No. 14-9533, pending before the U.S. Circuit Court of Appeals for the Tenth Circuit.

[5] *See State of Wyoming v. U.S. Environmental Protection Agency*, No. 14-9529; *Powder River Basin Resource Council v. EPA*, No. 14-9530; and *PacifiCorp v. EPA*, No. 14-9534, all pending before the Tenth Circuit.

measures and requirements for reducing CO_2 emissions from power plants within each particular state. EPA's final Clean Power Plan (CPP) regulations aim to reduce CO_2 emissions from existing fossil-fueled power plants by 32 percent from 2005 levels by 2030. The reduction is to be achieved by states meeting state-by-state CO_2 "goals," under either a mass-based or rate-based limit. LRS is the only MRES resource that is designated as an affected electric generating unit (EGU) under these rules.

In August 2015, EPA finalized the CPP regulations to reduce CO_2 from existing power plants, as well as those applicable to new, modified, and reconstructed sources. The regulations have been appealed. The United States Supreme Court issued a stay of enforcement, barring implementation of the CPP pending the final outcome of the litigation. Given the extraordinary significance of these regulations, the appeal will be considered by the entire Circuit Court of Appeals for the District of Columbia in September 2016. A decision is expected in 2017, which is likely to be appealed to the Supreme Court. The final outcome of the CPP is unlikely to be known for several years.

MRES actively engaged in the EPA rulemaking process, and is also engaged in the corresponding state efforts to develop compliance plans. MRES regularly discusses with federal and state regulators – including Wyoming state agencies – and industry stakeholders to address important interstate issues of the CPP and related model trading rules given that the only MRES affected EGU is located in Wyoming, and the Members' load is located in Iowa, Minnesota, North Dakota, and South Dakota. Engagement involves one-on-one meetings with agency staff, participation in state, regional and national stakeholder and forum discussions, as well as participation in and monitoring of activities of National Association of Regulatory Utility Commissions, National Association of Clean Air Agencies, RTOs, and other influential thought leaders and trade associations.

MRES is undertaking a systematic analysis of the proposed CO_2 rules to understand the potential impact of different scenarios, given that it is unlikely that the five states in which it operates will develop the same implementation plans. MRES is performing internal analysis, and is engaging a consultant to conduct additional modeling to inform its planning efforts. Regardless of the stay of enforcement of the CPP or whether the CPP is ultimately invalidated on appeal, MRES continues its efforts to address mandates to reduce CO_2. MRES acknowledges that the Supreme Court has ruled that CO_2 is a pollutant that must be regulated, whether that is based on the CPP or another law or regulation, and it has a fiduciary responsibility to the Members and their customer-owners to prepare for this significant change.

MRES staff continues to internally evaluate the potential impact of the CPP based on various state implementation plan scenarios, and has engaged a consultant to perform independent scenario analysis. In addition, MRES actively engages in dialogue with regulators and stakeholders in each of its constituent states – Iowa, Minnesota, North Dakota, South Dakota, and Wyoming – to develop a flexible and workable set of state implementation plans that achieve the objectives of EPA, while representing its members to ensure reliability and affordability for consumers. Given the challenges faced by coal resources, MRES continues to focus expansion efforts on non-coal resources, consistent with its Base Case from the 2011-2025 Resource Plan.

The assumptions for this resource planning study, and the scenario models, were developed based on the status of environmental regulations as of September 1, 2015. Further details of the following impacts are provided in Section IV:

- Regional Haze: To provide a basis for developing scenario models, it was assumed that each of the three units at LRS is required to install SCR. This is based on the existing EPA FIP for Wyoming, including the provisions related specifically to LRS, and assumes that these regulations will survive the current legal challenge pending before the Tenth Circuit Court of Appeals.
- Clean Power Plan: A sensitivity case was added to examine the potential impact if compliance with the CPP forces LRS to shut down one of the three units by 2022.

1.2.5. MRES DSM Program Implementation

In preparation for this report, MRES commissioned an updated study of the maximum amount of DSM that realistically can be implemented for its Members' retail customers, under certain avoided cost assumptions provided by MRES. The study results show an expected potential for DSM of up to 96.5 MW saved, coincident with the peak demands of the MRES Member loads, by 2031. Implementation has been well underway on an MRES-wide basis, as described in Part III, "Demand Side Management." MRES is also assisting its Minnesota Members with pursuing additional amounts to fulfill the state's CIP goals. Additional details are provided in Section 3.5 and Appendices H and I.

1.2.6. Energy Conservation Impacts

The 2007 Minnesota legislature enacted amendments to the CIP law, requiring utilities to adopt "an annual energy savings goal equivalent to 1.5 percent of gross annual retail energy sales" beginning in 2010. 2007 Minn. Sess. L. ch. 136, art. 2, § 5, codified at Minn. Stat. § 216B.241, subd. 1c. MRES is actively pursuing implementation of up to 79.5 MW of DSM for all of its Members by 2025, and in addition is assisting its

Minnesota Members in implementing the additional savings required to meet this Minnesota goal. Additional details are provided in Appendix H.

In 2011, the Minnesota legislature made further amendments to direct electric utilities to estimate the cost of complying with the renewable resource requirements. Each electric utility must submit with their Integrated Resource filing a report containing an estimation of the rate impact of activities of the electric utility necessary to comply with the requirements. Those activities include energy purchases, generation facility acquisition and construction, and transmission improvements. The Minnesota Public Utilities Commission (Commission) developed a uniform system for utilities to use when estimating and reporting the rate impacts. The uniform system provides further guidance as to the types of costs that are to be included and the years to be covered by the reports. The MRES renewable energy cost impact report is provided in Appendix K.

1.2.7. WAPA Area Integration into SPP

On October 1, 2015, WAPA merged its transmission system into the SPP market area. Much of the MRES resource supply relies on WAPA transmission for deliveries to Member loads, so this action also brought MRES loads and resources into the SPP footprint, including three Minnesota Members: Luverne, Madison, and Moorhead.

As a result, all MRES loads and resources are now located within either the MISO or the SPP markets. SPP currently has a 13.64% planning reserve requirement for its Members. This resource plan assumes the 13.64% requirement for all MRES load in SPP. While this is higher than the MISO resource adequacy requirement of 7.1% which is applied to all MRES load in MISO, the two RTOs have different rules for how to measure the amount of capacity that can meet the resource requirements.

In the past, a portion of the MRES energy and planning capacity requirements in MISO were met using MRES resources located outside of MISO. This required the purchase of firm transmission service across the WAPA transmission system. Now that WAPA's transmission facilities are under the functional control of SPP, it is no longer financially feasible to purchase such transmission across SPP. For that reason, only resources located within the respective RTO are used to meet MRES energy and capacity requirements of that RTO as of October 2015, with limited exceptions as discussed later.

1.2.8. Load Changes

WAPA Contract Extension: Since the previous resource plan filing, WAPA has extended its contracts with its customers that have firm hydropower allocations beyond the year 2020. The new contracts will be effective from 2021 through 2050, and allow for reductions in the WAPA contract amount of no more than 1% at the beginning in 2021 and again beginning in 2031. Any reduction in power supply deliveries from WAPA to a Member community results in a corresponding increase in the amount of power MRES is required to supply based on the contractual obligation of MRES to provide all supplemental power supply to S-1 Members.

S-1 Members: As noted, MRES has a uniform, long-term power sale agreement with each of its 57 S-1 Members. MRES recently amended the S-1 Agreement to address the changes brought on by WAPA's action to join SPP and transfer its facilities to SPP, to address changes to physical and financial markets, to provide for transmission service as a separate obligation, to extend the term of the S-1 Agreement to January 1, 2057, and to make other updates to the agreement. Also notable, the supplemental load of S-1 Member Marshall, Minnesota, increased by 50 MW on July 1, 2016.

Non S-1 Members: MRES provides power supply to three Members pursuant to individual agreements that are substantively different from the S-1 Agreement, each of which is unique. Since the date of the last MRES Resource Plan filed with the Commission, the community of Pella, Iowa joined MRES.[6] As noted previously, Pella has a Non S-1 Agreement and MRES began supplying their community in April 2012. MRES obligations to the three Non S-1 Members, through the years covered by this filing, are briefly described here.

1. Atlantic, Iowa: Contract for power supply needs supplemental to WAPA allocation and other resources owned by Atlantic, delivered in whole MW increments that are established once each year. The amounts to be delivered by MRES are estimated to be 1 MW of capacity and energy in all hours through 2025, then increasing to 3 MW by 2031.[7] This IRP does not include any Atlantic load or resources in excess of the contract amount.

2. Pella, Iowa: Contract to supply all requirements for capacity and energy. Pella's peak demand requirements increase from 42.9 MW in 2017 to 50.4 MW in 2031. The Pella Power Sale Agreement was recently amended to reflect changes similar to those made in the S-1 Agreements, including an extension to 2057.

[6] MRES notified the Commission of the addition of Pella, Iowa to the membership on June 27, 2011. *See* "Reply Comments of Missouri River Energy Services and Notice of New MRES Member," *In re MRES 2011-2025 Resource Plan*, Docket ET10/RP-10-735, Minnesota Public Utilities Commission, June 27, 2011.

[7] The Atlantic contract presently runs through 2030. For purposes of this resource plan, it was assumed this contract will be renewed under similar terms beginning in 2031.

3. Hutchinson, Minnesota: Contract for 25 MW of capacity and energy in all hours through January 1, 2046 when the contract term expires. This IRP does not include any Hutchinson load or resources in excess of the contract amount.

There have been no other changes regarding power supply Members of MRES.[8]

1.2.9. Resource Changes

As MRES has pursued its strategy to diversify resources, the Western Minnesota and MRES Boards of Directors have been conscious to ensure that resource additions include low- or non-CO_2 resources when possible. In fact, for the past twenty years nearly all energy resource additions (both owned and those acquired under long-term contracts) have been from non-emitting resources or low-emitting natural gas, including over 80 MW of wind, over 30 MW of nuclear, and 140 MW of natural gas generation. Most notably, the Red Rock Hydroelectric Project, which is presently under construction on the Red Rock Reservoir near Pella, Iowa, is expected to provide up to 55 MW of baseload energy from clean, non-emitting hydropower when it becomes commercially available in 2018.

Changes to the MRES generation portfolio since the last resource plan include:

Pella Generation: When MRES began serving the full requirements of Pella, Iowa in April 2012, MRES began receiving rights to certain power supply facilities:

1. MRES acquired Pella's right to 3.3 MW of wind resources from the Hancock wind farm in Iowa. Energy from this (and other wind resources) is sold into the MISO market, providing a financial hedge (economic offset) against other MRES production and purchase expenses.
2. MRES has contracted for the Municipal Capacity of Pella's local generation, consisting of 14 diesel units rated at 2 MW each; the rating net of station service is about 25.4 MW.

By obtaining power supply from MRES, the city of Pella was able to permanently retire its 25 MW coal plant that was in daily operation until that time.

Marshall Wind and Municipal Capacity: In June 2014 the telemetering for Marshall was modified so the city is now in the MISO region instead of in the SPP region. Thus the 15.2 MW of municipal generation, along with the 18.7 MW wind project near Marshall,

[8] One change in the MRES membership did occur in 2015, when the community of Fontanelle, Iowa, withdrew as a member. Fontanelle was the only MRES Member that did not have any prior power supply arrangement with MRES, and thus this change is not material to the resource plan.

are now in the MISO footprint. They had been included in the previous IRP filing as being in the WAPA area.

Point Beach Nuclear Power Purchase Agreement: In 2011, MRES entered into an agreement with WPPI Energy to obtain a share of the two Point Beach nuclear units.[9] The amount of capacity is 32.8 MW, reducing to 16.4 MW after 2030.

Short-term Capacity Transactions: While about half of the MRES load is in SPP, the bulk of MRES resources are located in SPP. This has resulted in a surplus of capacity in SPP and a shortfall of capacity MISO for MRES. To date, MRES has entered into the following capacity-only transactions (energy production is not affected). The sales amounts are in SPP, and the purchase amounts are in MISO:

1. SPP: Sale to Northwestern Energy of 30 MW of capacity for 2017 and 35 MW for 2018.
2. SPP: Sale to Basin Electric Power Cooperative of 150 MW of capacity for the six years of 2018 through 2023.
3. MISO: Purchase from Great River Energy (GRE) of 100 MW of capacity for the years 2017 and 2018.
4. MISO: Purchase from Morgan Stanley of 50 MW of capacity for the years 2017 and 2018.
5. MISO: Purchase from Morgan Stanley of 100 MW of capacity for the years 2019 through 2021.

Other MRES Resources: Recent EPA rules affecting small generators have caused the loss or replacement of some capacity:

1. Some municipal capacity has been retired since the last resource plan filing rather than undergo the modifications required to meet EPA standards applicable to Reciprocating Internal Combustion Engines (RICE rules). Alexandria and Benson, Minnesota both retired a portion of their capacity. In addition, Moorhead and Melrose, Minnesota each replaced one of their units with a slightly larger new unit. The net effect of these changes was a decrease of about 8.9 MW in MRES capacity.
2. The previous resource plan included 3.7 MW of retail commercial and industrial load reductions under the MRES Interruptible Load Agreement. Most of the generating units under that agreement were unable or unwilling to meet the EPA RICE rules

[9] *See* "Notice of Change in Circumstances," *In re MRES 2011-2025 Resource Plan*, Docket ET10/RP-10-735, Minnesota Public Utilities Commission, September 7, 2011. MRES notified the Commission of several changes in this filing, including the Point Beach Nuclear Power Purchase Agreement.

necessary to remain under contract. As a result, MRES has terminated the entire Interruptible Load Agreement program.

New Resources Under Construction: Notably, MRES is currently working on development of two renewable energy projects. The first is the Red Rock Hydroelectric Project (RRHP), an electric generating plant at the existing Red Rock Reservoir and Dam on the Des Moines River in Iowa. The dam is owned by the federal government and operated by the U.S. Army Corps of Engineers. The project is owned by Western Minnesota and will be operated by MRES. When completed in 2018,[10] RRHP will be capable of generating 36 MW of base load electricity under normal spring and summer water levels, and up to 55 MW at times of high reservoir levels. RRHP is an attractive option for MRES because it will generate clean, renewable, and reliable baseload energy. Hydropower is the only demonstrated renewable resource that is able to add much-needed inertia to electric grid as a baseload resource. This investment in hydropower is the first in this region in decades, and further diversifies the MRES generation portfolio with even more capacity from another non-emitting resource. In addition, RRHP also adds to the ability of MRES to comply with state renewable energy mandates and goals.

The second project is the Pierre (South Dakota) Solar Project, which will be the first MRES utility-scale solar energy resource. The project was recently announced and will begin construction in July 2016.[11] When completed at the end of 2016, it will be capable of providing up to 1 MW of solar energy, making it the largest solar project in the state of South Dakota. MRES will purchase all of the output from Pierre Solar, LLC, a subsidiary of Geronimo Energy.

1.3. Other Topics from Previous Plan

1.3.1. Plug-in Hybrid Electric Vehicle Load

The previous resource plan filing included a forecast of Plug-in Hybrid Electric Vehicle (PHEV) load, with a coincident impact of up to 4.6 MW by 2025. The predicted amounts of PHEV have not materialized, and any revised lower forecast would have minimal impact on the resource plan. No PHEV load is explicitly modeled in this resource plan.

1.3.2. Compressed Air Energy Storage

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[10] MRES and Western Minnesota had committed to, and initiated construction of, RRHP when modeling for this resource plan was initiated. For that reason, RRHP was included as an existing resource beginning in 2018.

[11] MRES had not committed to the Pierre Solar Project at the time that modeling for this resource plan was initiated. For that reason, Pierre Solar was not specifically included in this model as an available resource.

The previous resource plan included the goal of investigating 45 MW of Compressed Air Energy Storage in the 2016 timeframe to serve the MRES requirements. As explained in the Notice of Change in Circumstances, the project was canceled in 2011 by the Iowa Stored Energy Project Agency, and MRES and Western Minnesota terminated membership in the project.[12] MRES and Western Minnesota are not involved in any similar projects.

1.3.3. Community-Based Energy Development

Since the prior resource plan, MRES has continued to make periodic reports to the Department of Commerce on the status of its participation in Community-Based Energy Development (C-BED) projects. MRES was an early and active participant in C-BED projects, including the Marshall and Odin wind projects. In February 2016, the Department advised that it is no longer collecting information on C-BED projects. Subsequently, the C-BED laws were repealed during the 2016 Legislative Session, *i.e.* Minn. Stat. § 216B.1612 (Community-Based Energy Development; Tariff), and Minn. Stat. § 216C.39 (Rural Wind Energy Development Revolving Loan Fund). In addition, other statutory references relating to C-BED were deleted from Minn. Stat. § 216B.1691, subd. 10, and Minn. Stat. § 373.49, subd. 3.[13]

1.4. Plan Cross Reference

Appendix A contains a cross-reference table to identify each statute and rule related to resource planning, and where each corresponding requirement is addressed in this document. It also contains cross-references for the applicable requirements from Commission orders approving prior resource plans of MRES and others that are generally applicable to all filing utilities.

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[12] *See* "Notice of Change in Circumstances," *In re MRES 2011-2025 Resource Plan*, Docket ET10/RP-10-735, Minnesota Public Utilities Commission, September 7, 2011.

[13] *See* Final Engrossment of House File 2749, signed by Gov. Dayton on June 1, 2016, and expected to appear as Minn. Sess. L. 2016, Ch. 189, Art. 6, Sections 6, 13, and 16, available at https://www.revisor.mn.gov/laws/?year=2016&type=0&doctype=Chapter&id=189 (last accessed June 29, 2016).

2. Resource Plan Summary

2.1. MRES

MRES is a Member-based, joint-action agency that provides power supply, transmission, and related services to its Member municipalities in Iowa, Minnesota, North Dakota, and South Dakota. Fifty-seven of the sixty Members receive power supply under identical long-term S-1 Agreements. All MRES S-1 Members receive hydroelectric allocations from WAPA. The three remaining Members each have individual and distinct long-term power supply agreements with MRES, and one of those Members also has an allocation of federal hydropower from WAPA.

Twenty seven Members, representing about half of the MRES energy sales, are located within MISO. The remaining 33 Members are located within SPP, as of October 1, 2015. In regard to the 24 MRES Members located in Minnesota, three are within SPP, and the remaining 21 are within MISO. Most MRES and WAPA generation resources are within SPP.

2.2. MRES Loads

MRES created load forecasts for the total load of each of its S-1 Members, plus Atlantic and Pella, Iowa. The MRES load forecasting methodology is described in Appendices E and F. Detailed results for each Minnesota Member are included in Appendix G. These forecasts are of the expected loads assuming normal weather, <u>before</u> any CIP reduction efforts or any additional DSM programs. DSM and CIP effects on the loads are calculated in a later step of the planning process to enable load and DSM forecasting to be separately evaluated on an ongoing basis.

Based on the WAPA contract extensions beyond 2020, the individual Member load forecasts assume the WAPA contract deliveries remain at present levels for each community with slight (1%) reductions in 2021 and 2031.

The total loads for the 57 S-1 Members plus the total loads of Atlantic and Pella are forecasted to reach 855.5 MW in the summer of 2016. This compares to an all-time historic peak of 898 MW in the summer of 2011. These loads are forecasted to reach 995.7 MW in the summer of 2031 in the Base forecast. In addition, MRES also is responsible for a sale of 25 MW to the remaining Non S-1 Member, Hutchinson, Minnesota, through the modeling period.

These load forecasts are adjusted to reflect the impact of future DSM and CIP reductions, and for other adjustments, as described below.

2.3. DSM Effects

2.3.1. Energy and Demand Savings Results

MRES and its Members have steadily moved forward with energy efficiency efforts to implement the savings goals set by the DSM Potential Studies, and to comply with state efficiency objectives under Minnesota Statutes § 216B.241, subd. 1c, and Iowa Code 476.6(15)(c). For instance, in 2014 the MRES Members saved an estimated 32.9 million kWh of energy and 6.2 MW of demand.

2.3.2. DSM Potential

MRES commissioned Morgan/Cadmus to perform a DSM Potential Study in anticipation of initiating modeling for this plan.[14] The final report for the study was completed in October 2014, and is included in Appendix H.

The MRES Base Case presented in this plan, assumes that the MRES Minnesota municipal utility Members will achieve (a) the full DSM Program Potential savings, plus (b) an additional incremental amount of savings to meet the full 1.5% per year energy savings target of the Minnesota CIP requirements.

The Program Potential amounts used in the Base Case are from the 2014 Morgan/Cadmus DSM Study, as estimated at the time of the MRES peak. These Base Case amounts are summarized in the following table:

[14] Given that this study was commissioned in early 2014, it addressed the DSM potential based on the entire MRES Membership, and it did not specifically include separate analysis of SPP and MISO regions.

Table 2-1 DSM Base Case Reduction Amounts						
	Expected Conservation Sensitivity Case		Additional Minnesota amounts to meet 1.5% CIP		Total Base Case	
Year	Energy Savings (GWh)	Coincident Demand Savings (MW)	Energy Savings (GWh)	Coincident Demand Savings (MW)	Energy Savings (GWh)	Coincident Demand Savings (MW)
2017	90.4	21.0	43.9	10.2	134.3	31.1
2018	121.0	28.3	58.3	13.6	179.3	41.9
2019	151.1	35.6	73.0	17.2	224.1	52.8
2020	178.5	42.8	89.0	21.3	267.5	64.1
2021	205.6	49.8	104.8	25.4	310.4	75.2
2022	232.5	56.8	120.8	29.5	353.3	86.3
2023	259.2	63.8	136.9	33.7	396.1	97.4
2024	285.8	70.6	152.9	37.8	438.7	108.4
2025	312.2	77.5	168.8	41.9	481.0	119.4
2026	338.6	84.3	184.8	46.0	523.4	130.3
2027	364.8	91.1	200.6	50.1	565.4	141.2
2028	368.5	92.5	227.9	57.2	596.4	149.7
2029	372.1	93.9	255.1	64.4	627.3	158.2
2030	375.7	95.2	282.2	71.5	657.9	166.7
2031	379.2	96.5	309.2	78.7	688.4	175.2

MRES also conducted one sensitivity case that models only the amounts of DSM that are identified as feasible under the Market Potential calculations from the Morgan/Cadmus DSM Study, as calculated at the time of the MRES peak, for all four states. This sensitivity case is referred to as “Expected Conservation.”

2.4. Planning Process

Minnesota Rule 7843.0500 establishes five factors the Commission considers when evaluating a resource plan. Those factors are consistent with the MRES mission statement, so MRES has adopted those same factors into its goals for this plan:

1. Maintain the Adequacy and Reliability of Power Supply;
2. Keep Members’ Wholesale Rates Competitive;
3. Minimize Adverse Socioeconomic and Environmental Effects;
4. Enhance the Ability of MRES to Respond to Changes Affecting Operations; and
5. Limit the Risk of Factors Beyond the Control of MRES.

These factors established the principles used to develop the resource plan.

As previously stated, in preparation for the resource plan, a DSM Potential Study was commissioned. MRES created updated short-term and long-term load forecasts for each member, using the methodology described in Appendices E and F. After that, the following steps were then followed to conduct the resource plan analysis:

1) Determine Capacity and Energy Requirements
2) Identify Resource Options
   a) Discuss Potential Options
   b) Refine Resource Options Available for the Plan
3) Identify Risk Factors to Analyze, including:
   a) Operations in Two RTO Markets
   b) Future CO_2 Emission Costs
   c) Uncertainty of Natural Gas and Electricity Market Price Forecasts
   d) Impact of Regional Haze and other CAA Regulations
   e) Load Forecast Uncertainty
   f) Inability to Achieve the Full 1.5% CIP Reduction
4) Evaluate a Range of Expansion Plans

When evaluating the range of expansion plans, scenarios were developed for each of the identified risk factors. Additional scenarios were also evaluated for obtaining 50% and 75% of future resources from conservation and renewable resources.

2.5. Separate Analysis for SPP vs MISO Areas

On October 1, 2015, WAPA merged its transmission system into the SPP market area, including facilities that serve MRES Member load. As a result, all MRES loads and resources are located within either the MISO or the SPP markets.

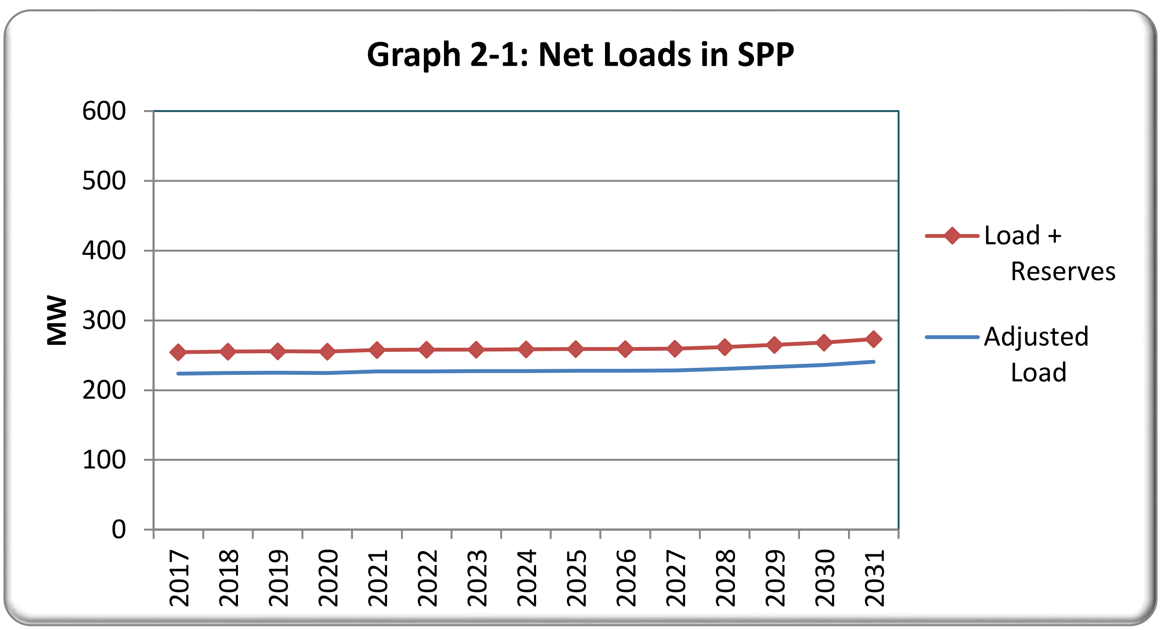
This resource plan assumes the planning reserve requirement as defined by SPP for all MRES load in SPP, along with the MISO resource adequacy requirements for load in MISO. Only resources within the same RTO, or that have appropriate firm transmission in place from another RTO, may be used to meet the capacity requirements in an RTO. MRES has very limited transmission rights between the two RTO regions. In order to calculate the overall resource requirements, the capacity expansion modeling was divided into separate models for each RTO region.

As a first step, the total load forecasts for MRES Members, as well as the DSM potential results, were divided between the SPP and MISO regions. Current as well as potential resources were identified for each region as well before performing the capacity expansion modeling.

2.6. Load Adjustments – SPP Region

To determine the amount of MRES planning reserve capacity required for the SPP region, the following steps were followed in sequence:

1) The MRES total load forecast was obtained for the Members in the SPP region only.
2) The WAPA power supply was subtracted from the total loads to determine the MRES capacity requirement. WAPA is the market participant in SPP for their portion of the Member load, and thus MRES is not responsible for meeting the WAPA capacity requirement in this RTO.
3) The amount of the MRES capacity requirement was adjusted to reflect future DSM and CIP impacts. This amount is referred to as "Adjusted Load" in Graph 2-1.
4) The results were further adjusted for peak load coincidence and the SPP planning reserve requirement of 13.64%. This amount is referred to as "Load + Reserves" in Graph 2-1.

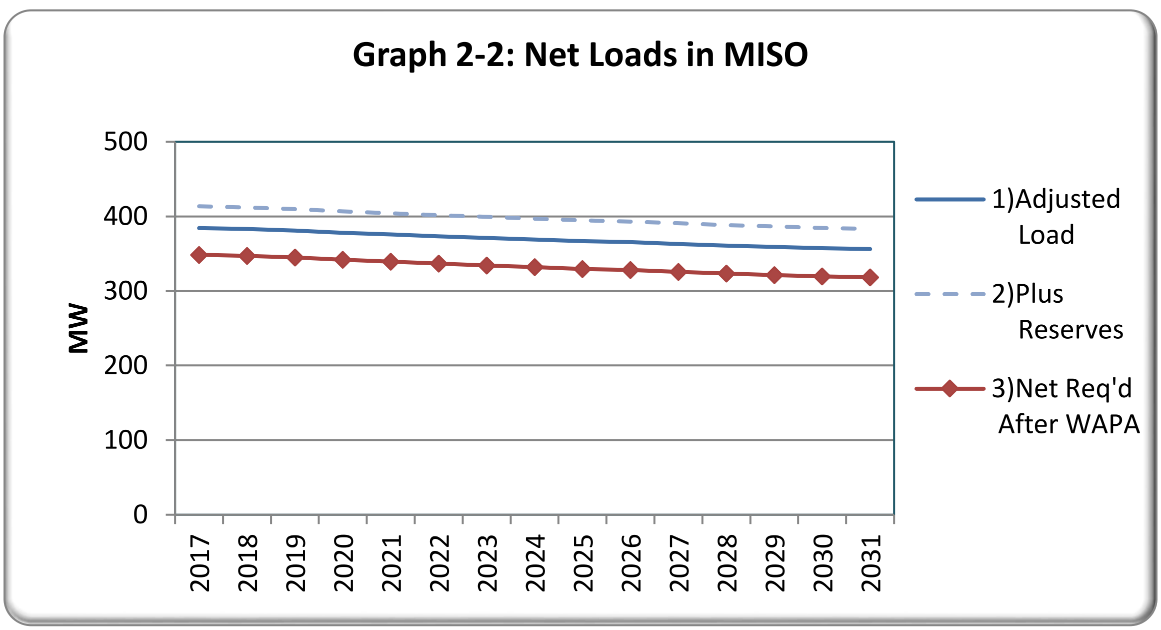


2.7. Load Adjustments – MISO Region

In MISO, MRES is the market participant representing the full requirements of its S-1 Member loads, including load served via their WAPA power supply. (MISO rules do not permit multiple power suppliers for a single load.) In effect this makes MRES the full-requirements supplier for those Members. In return, MRES receives MISO credit for the energy and capacity delivered by WAPA on behalf of the Members.

To determine the amount of MRES planning reserve capacity required for the MISO region, the following steps were followed in sequence:

1) The MRES total load forecast was obtained for the Members in the MISO region only. In MISO, MRES is responsible for planning reserve capacity on the WAPA portion of the load as well, so that load is not subtracted from the total.
2) The portion of the Atlantic, IA capacity requirement that is not the responsibility of MRES was subtracted.
3) The amount of the MRES capacity requirement (including the remaining Atlantic requirement) was adjusted to reflect future DSM and CIP impacts.
4) The results were then increased to account for the 25 MW sale to Hutchinson, MN. This amount is referred to as "Adjusted Load" in Graph 2-2, which follows.
5) The results were further adjusted for peak load coincidence, losses, and the MISO planning reserve requirement of 7.6%. This amount is referred to in Graph 2-2 as "Plus Reserves."
6) WAPA supplies capacity towards the MISO planning reserve obligation for its share of the load, but due to its transmission arrangements MRES is not able to receive credit for all of it in MISO. MRES incurs an additional amount of planning reserve requirement in MISO due to this shortfall of WAPA capacity. This resulting amount is referred to in Graph 2-2 "Net Req'd After WAPA."



2.8. MRES Resources – SPP Region

The MRES generation resources in SPP total 495.8 MW and consist of the following:

1. MRES share of LRS: 281.8 MW
2. Exira Station: 140.0 MW
3. Watertown Peaking Plant: 45.9 MW
4. Municipal Capacity:[15] 28.1 MW

The largest resources are the MRES share of LRS, the only MRES coal resource, located near Wheatland, Wyoming, and Exira Station, a natural gas peaking plant located near Atlantic, Iowa.

MRES has a substantial surplus of capacity in the SPP region. The cost of firm transmission makes it uneconomical to transfer capacity rights to the MISO market, where MRES has a capacity deficit. Given this excess SPP capacity that cannot be utilized by MISO load, MRES has made several short-term capacity sales. The following capacity sales transactions are included in this resource plan as reductions in resource capacity in the SPP region:

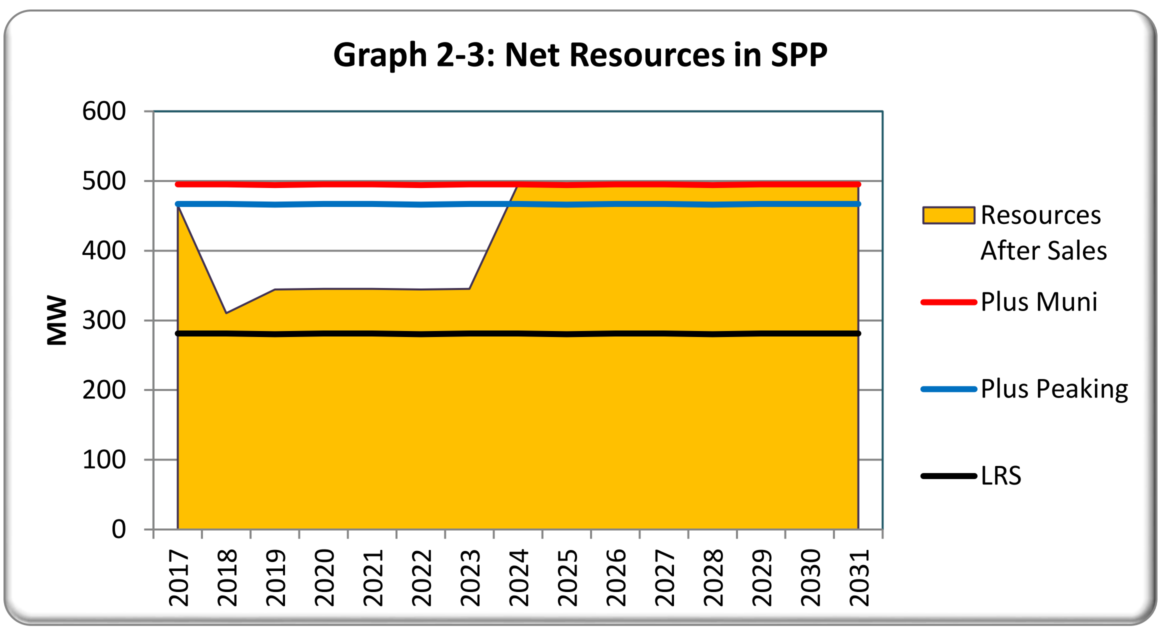
- Sale to Northwestern Energy of 30 MW of capacity for 2017 and 35 MW for 2018.
- Sale to Basin Electric Power Cooperative of 150 MW of capacity for the six years of 2018 through 2023.

The MRES loads in the SPP region, plus the required capacity reserve margin, are shown in Table 2-2 below. Also shown are the net amount of MRES capacity resources and the remaining surplus capacity in SPP.

[15] The contracts for the various municipal capacity from MRES Members expire prior to 2031. For purposes of this resource plan, it is assumed that the contracts will each be renewed through the planning period.

Table 2-2 SPP Requirement vs Resource Amounts (MW)			
Year	**Load Plus Reserve Requirement**	**Resources After Sales**	**Surplus Capacity**
2017	254.5	465	210.5
2018	255.5	311	55.5
2019	255.7	346	90.3
2020	255.3	346	90.7
2021	257.9	345	87.1
2022	258.0	346	88.0
2023	258.2	346	87.8
2024	258.7	496	237.3
2025	258.9	495	236.1
2026	259.1	496	236.9
2027	259.4	496	236.6
2028	262.0	496	234.0
2029	265.1	495	229.9
2030	268.2	496	227.8
2031	273.5	496	222.5

Future wind resources are modeled in the expansion plan cases as needed to meet both the Minnesota RES, as well as a 10% renewable goal for Iowa (assumed[16]), North Dakota, and South Dakota. MRES has no existing wind resources located in the SPP region.



[16] Iowa has no applicable renewable energy mandates or goals, although both North Dakota and South Dakota have voluntary 10% goals. *See* NDCC § 49-02-28 through 49-02-34; SDCL § 49-34A-101 through 106. MRES has chosen to provide Iowa members with 10% renewable energy, consistent with the other two states.

2.9. MRES Resources – MISO Region

The MRES generation resources in MISO have a total ICAP rating of 281.6 MW and consist of the following:

1.	Municipal Capacity:	106.3 MW
2.	Point Beach Nuclear Purchase:	32.8 MW
3.	Red Rock Hydro Project (2018):	55.0 MW
4.	Wind Capacity:	85.7 MW

The estimated UCAP rating for those resources, which accrues towards the planning reserve requirements, is 175.8 MW. MRES has no coal resources in the MISO region.

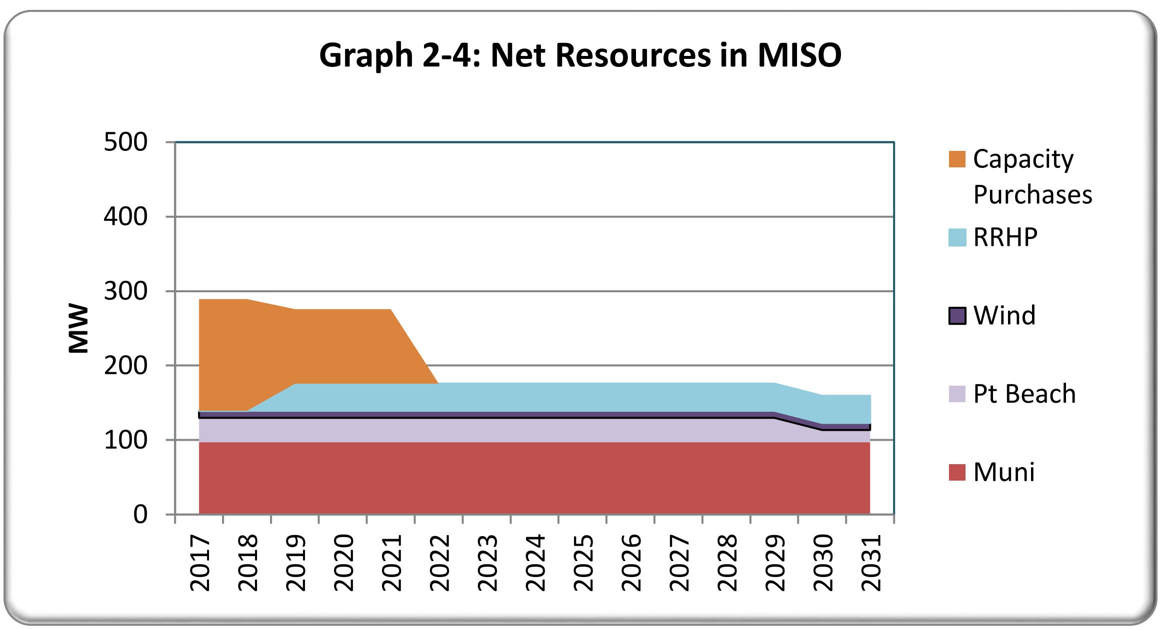
The division of MRES power supply between the MISO and SPP markets results in a large deficit of generating capacity in the MISO region as compared to load. The following purchase transactions are included in this resource plan as increases in resource capacity in the MISO region:

- Purchase from GRE of 100 MW of capacity for the years 2017 and 2018.
- Purchase from Morgan Stanley Capital Group, Inc. of 50 MW of capacity for the years 2017 and 2018.
- Purchase from Morgan Stanley of 100 MW of capacity for the years 2019 through 2021.

The MRES loads in the MISO region, including the required capacity reserve margin and any received credit WAPA capacity, are shown in Table 2-3 below. Also shown are the net amount of MRES capacity resources including purchases, and the remaining capacity deficit in MISO.

Table 2-3 MISO Requirement vs Resource Amounts (MW)			
Year	**Net Required After WAPA**	**Resources and Purchases**	**Capacity (Deficit)**
2017	348.1	289.3	(59)
2018	346.5	289.3	(57)
2019	344.3	275.8	(69)
2020	341.2	275.8	(65)
2021	338.9	275.8	(63)
2022	336.2	175.8	(160)
2023	333.8	175.8	(158)
2024	332.3	175.8	(157)
2025	329.8	175.8	(154)
2026	328.4	175.8	(153)
2027	326.0	175.8	(150)
2028	323.8	175.8	(148)
2029	321.7	175.8	(146)
2030	319.8	159.4	(160)
2031	318.7	159.4	(159)

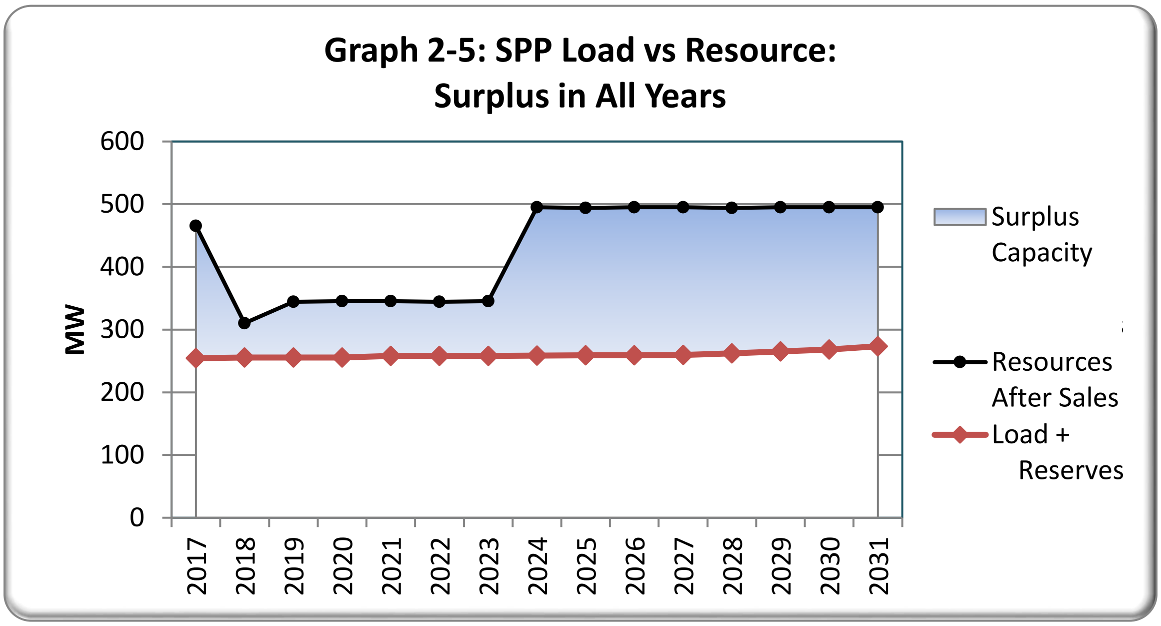
The Strategist® capacity expansion model adds wind resources as needed to meet the Minnesota RES, as well as a 10% renewable goal for Iowa (assumed), North Dakota, and South Dakota.



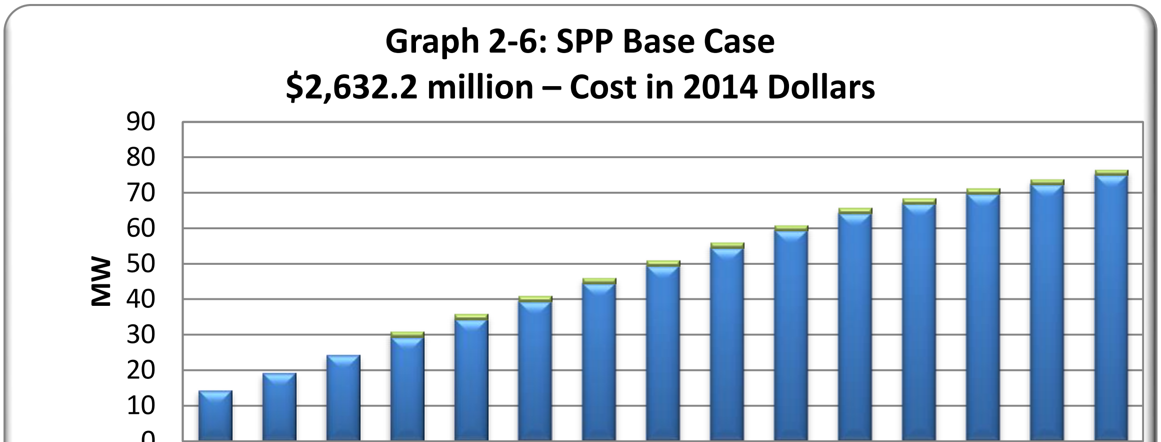
2.10. Resource Plan

The graphs below visually summarize MRES demand in comparison to supply resources, in both SPP and MISO. They show the final adjusted forecasted MRES demand including all adjustments. Also shown is the MRES responsibility including planning reserve requirements, as compared to the total existing capacity ratings that apply toward meeting those reserve requirements. As these charts show, using current resources and transactions only, MRES has surplus capacity in all years in SPP and is deficit in capacity in all years in MISO.

To begin, the SPP modeling demonstrates a capacity surplus over the 2017-2031 planning period, as illustrated below.



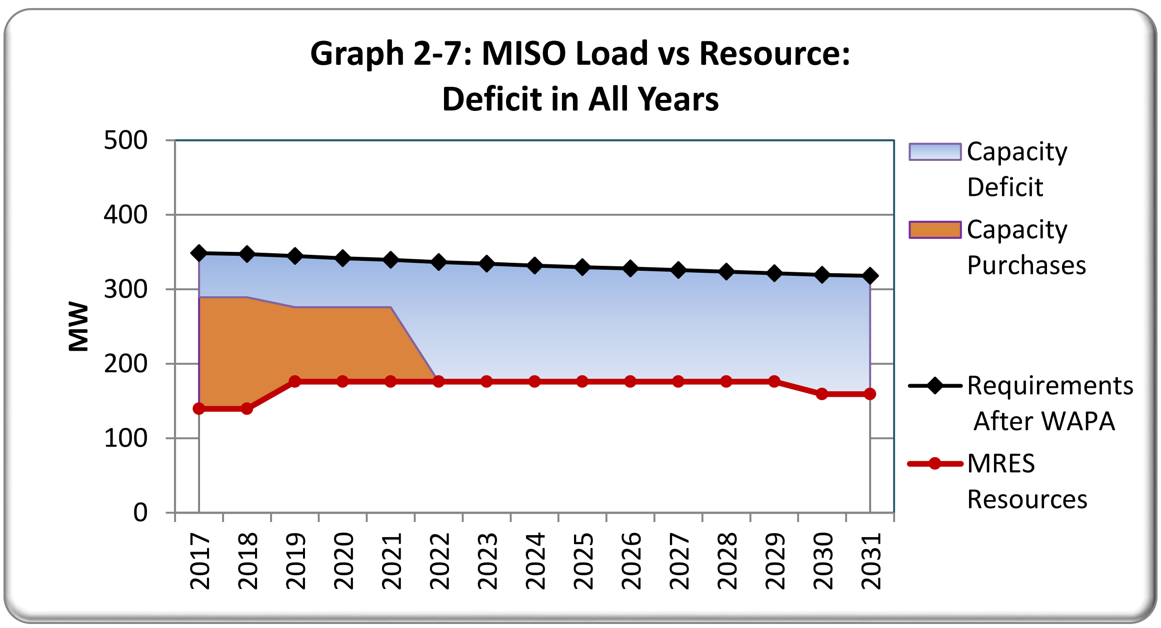
As indicated, MRES has surplus capacity through 2031 in the SPP Base Case, and the modeling for the Base Case assumes the continued pursuit of DSM and Conservation as described above. While there is surplus capacity for the planning period, the Base Case model results in the addition of approximately 10 MW (nameplate rating) of wind resources (which results in accredited capacity of 1.5 MW of wind) to maintain the targeted amount of renewable resources. A summary of the amounts of added wind and DSM/CIP for the planning period is depicted in the following graph:



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind				1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
DSM/CIP	14.3	19.2	24.3	29.4	34.4	39.5	44.5	49.5	54.5	59.4	64.3	67.0	69.7	72.4	75.1

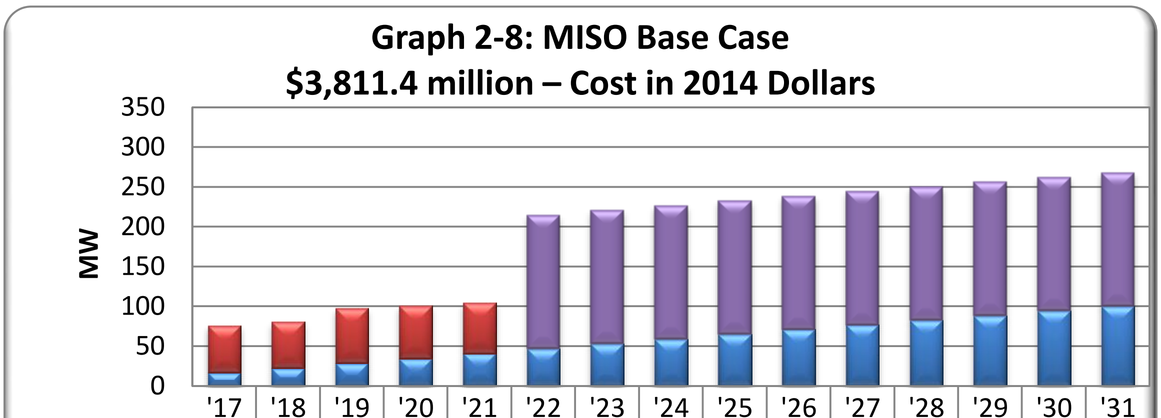
In summary, the SPP Base Case modeling results in changes to the status quo that rely entirely on the addition of more conservation and renewable energy. All SPP additions for the next 15 years are 100% renewable or DSM/CIP resources.

Next, the MISO modeling illustrates a capacity deficit over the planning period, as illustrated below:



To the extent MRES remains capacity deficit in each upcoming year, the deficiency must be purchased in the annual MISO capacity auction. To address the projected deficit, MRES plans to increase its MISO capacity over time to eliminate most or all of its annual auction purchases. Specifically, the Red Rock Hydroelectric Project is scheduled to become commercially available in 2018, and capacity purchases have been made from GRE and Morgan Stanley for 2017 through 2021. Those additions will reduce the capacity deficit in 2017-2021 to approximately 60 to 70 MW, which can be addressed through annual capacity auction purchases. After 2021, the MISO deficit is approximately 160 MW. This resource plan assumes that new resources can be added (whether through direct ownership or otherwise) to avoid all forecasted capacity deficits beginning in 2022.

For the MISO Base Case, additional capacity is required by 2022. To address this deficit, the model added new generation[17] of approximately 168 MW (in the form of simple-cycle combustion turbine capacity), along with continued additions of DSM and Conservation, as described above. The graph below illustrates the resource additions necessary to address the projected capacity deficits in MISO.



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Future CT						168	168	168	168	168	168	168	168	168	168
Purchase	59	58	69	66	64										
DSM/CIP	16.9	22.6	28.5	34.7	40.8	46.9	52.9	58.9	64.9	70.9	76.8	82.6	88.5	94.3	100

In the graph above, the "Purchase" entry indicates one-year capacity purchase amounts during the short term (first five years).

In presenting the planning results for both SPP and MISO Base Cases, the costs reflected in the graphs above include the production costs for existing and future resources, plus capital costs for all new resources. (The results do not include capital costs for existing resources.) Emissions

[17] The new generation additions identified by Strategist are based on generic natural gas CT units, with the assumption that each CT unit is 83.8 MW, and additions are made in multiples thereof. The addition of 168 MW does not necessarily reflect the amount of capacity needed in each year.

costs and market energy purchase costs were also included. When determining the optimal resource mix, the plan was developed based only on the needs of firm Member loads. After the optimal resource mix was determined to meet firm load forecasts, a final modeling run was performed for each scenario with the optimal resource mix locked in and which included revenue from sales in excess of Member needs to account for surplus sales in the MISO and SPP markets.

The discussion above summarizes the SPP and MISO Base Case results, both in terms of capacity needs and costs. Along with the Base Case, the following sensitivity analysis scenarios were also run for both SPP and MISO:

- Zero, $21.50 (Base Case), and $34 CO_2 emission costs
- High electricity market and natural gas prices
- Low and high load forecasts
- LRS reduction (SPP cases only)
- 50% and 75% renewable capacity (MISO only)
- Expected DSM for all Members

Modeling these sensitivity cases provided information vital to the analysis of the future variables that might affect the Base Cases and, ultimately, the results of the resource plan as a whole.

2.11. IRP Results

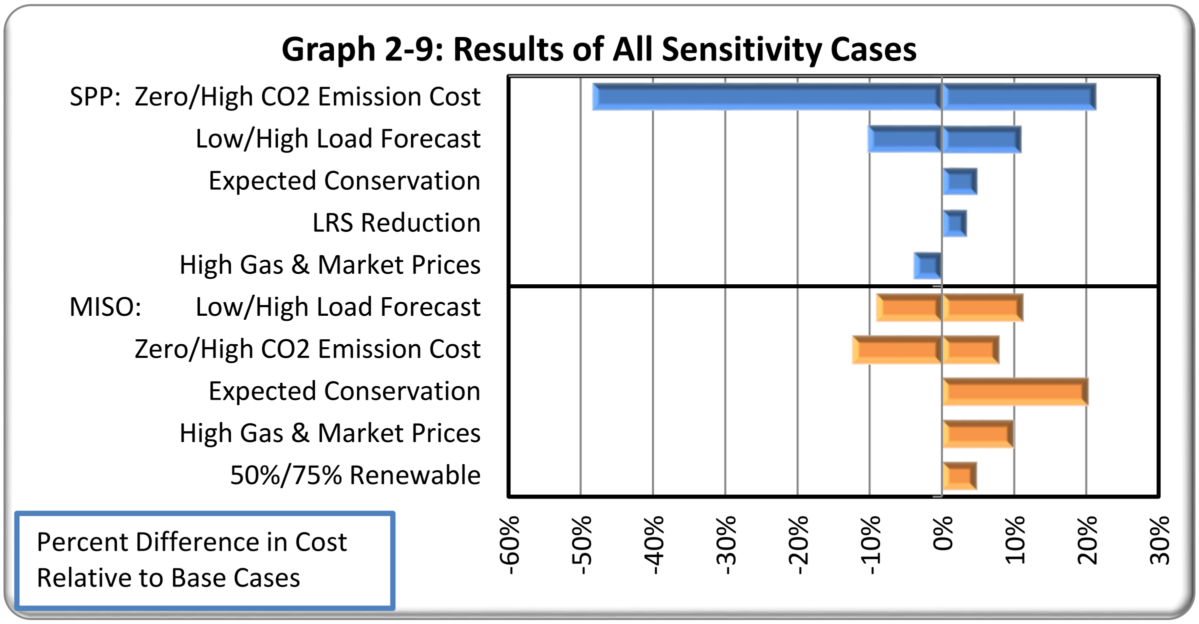
2.11.1. Base Case Results

The SPP Base Case, as well as all of the SPP sensitivity cases, show little need for additional capacity in SPP, beyond the DSM amounts in the study. This is consistent with the large amount of surplus capacity that MRES holds in that region. The SPP cases all show a need for a relatively small amount of wind resource in 2020 to meet renewable objectives. Additional wind may be needed toward the end of the study in some sensitivity cases.

In MISO, the Base Case shows an almost immediate need for capacity, and includes DSM as well as 168 MW of additional capacity by 2022 (modeled as natural gas CT generation). In the MISO sensitivity cases, the optimal results may add wind capacity or modify the amount of CT capacity included.

2.11.2. Sensitivity Case Results

The graph below summarizes the results of the sensitivity cases for both SPP and MISO. As illustrated, in SPP the relative costs compared to the Base Cases vary considerably for the CO_2 emission cost sensitivity cases. Overall load growth is the second highest sensitivity factor for SPP. In contrast, the MISO scenarios do not show as much sensitivity to the variables. The analysis shows that the overall load growth, CO_2 emission costs, and the potential impact of failing to achieve the full 1.5% conservation goals are the more significant factors in MISO.



The remaining sensitivity cases have only moderate impact on long-term costs (less than 20% on an overall present-worth basis). This demonstrates that the case work and results are relatively robust, even under a variety of alternative assumptions.

2.11.3. Renewable Energy Cost Impact

Minnesota law requires each electric utility to estimate the cost of complying with the state's renewable resource requirements, including an estimation of the rate impact of activities of the electric utility necessary to comply with the renewable energy standard (RES).[18] Those activities include energy purchases, generation facility acquisition and construction, and transmission improvements. The Commission developed a uniform system for utilities to use when estimating and reporting the rate impacts. The uniform system provides further guidance as to the types of costs that are to be included and the years to be covered by the reports. The MRES RES rate impact report is provided in Appendix K.

[18] Minn. Stat. § 216B.1691, subd. 2e.

2.12. Action Plan

During the next five years, MRES will need to continue its efforts to address its capacity shortfall in the MISO market. This includes completion of the Red Rock Hydroelectric Project, and obtaining additional peaking capacity. Efforts to secure peaking capacity will include pursuing agreements with potential capacity suppliers, and investigating ownership of new peaking capacity projects to evaluate the most appropriate alternative(s).

Another important task in the short term is to continue assisting Members with implementing their DSM and conservation activities, to contain overall load growth. For the Minnesota Members, this means maintaining concerted activities to pursue DSM measures to meet the Minnesota CIP requirements. Appendix H describes activities underway to support these efforts.

Wind or other renewable resources will continue to be obtained as needed to continue to enhance the clean energy portion of the MRES resource mix. These renewable additions will ensure that MRES will meet the goals established by the Board of Directors of achieving both the Minnesota RES as it expands and meeting any renewable energy objectives established in Iowa, North Dakota, and South Dakota.

Further, as part of the five year Action Plan, MRES will continue its active efforts to participate in activities at both the federal and state levels to develop enforceable and workable regulations to reduce CO_2 in an effort to minimize the potential reliability and economic impacts of such emission regulations. MRES is committed to active and constructive engagement on this vital issue to ensure a reasonable approach to carbon reduction and environmental stewardship, while also balancing the needs of consumers for reliable and affordable electricity to power the clean energy future.

In summary, during the next five years MRES has a need for additional capacity – including a small amount of additional renewable capacity. Once that need is met, under both SPP and MISO Base Case conditions, additional needs may be met through further development of DSM and conservation activities.

3. MRES DSM Background

This section discusses the MRES activities related to DSM that have occurred since the previous IRP filing, and how the results were used in this IRP analysis and filing.

3.1. DSM Potential Studies

MRES and its Members view DSM activities as a means to delay or reduce the size of future power supply resource development or purchases, to reduce purchases on the energy market, and to build customer-owner relationships by helping customers save energy and money. In that spirit, MRES and its Members have committed to pursue energy efficiency and demand reduction as an integral part of the least cost resource plans. To help MRES determine where to focus its efforts to develop the most effective programs, MRES arranged for its own DSM potential studies in 2006, 2009, and most recently in 2014. The 2014 DSM potential study was conducted by Morgan Marketing Partners and the Cadmus Group (the Morgan/Cadmus DSM Study) and covered the time period of 2015 through 2039. These DSM potential studies evaluate DSM based on the actual characteristics of the entire MRES Membership. Additional details are provided in Section 3.5 and Appendices H and I. In addition, MRES has a fully-developed Energy Services staff that works directly in Member communities with Members and their customers to evaluate and implement efficiency and conservation measures in Iowa, Minnesota, North Dakota, and South Dakota.

3.2. Minnesota CIP Goals

Among the MRES Member states, only Minnesota has a statutory energy savings goal. The Minnesota Conservation Improvement Program (CIP) establishes a specific policy goal of 1.5% annual energy savings. Minn. Stat. §§ 216B.2401, 216B.241. This energy savings goal requires significant effort and investment in energy efficiency, which MRES coordinates for its Members. MRES and its Members conduct strategic planning sessions every three years to determine how to best implement efficiency efforts to meet these requirements. The most recent strategic planning sessions were held during the summer of 2014, in conjunction with the 2014 Morgan/Cadmus DSM Study.

The DSM goals used in this IRP are based on an annual savings of 1.5% of retail sales, in kWh, for the MRES Minnesota Members to reflect the statutory CIP policy goal. The following table, Table 3-1, shows the amount of energy savings needed to achieve the 1.5% goal based on the current load forecast, along with the expected amount of demand savings that are anticipated to occur when making those energy reductions:

Table 3-1 MRES Minnesota Member 1.5% Energy Savings Goals		
Year	**Energy Savings (GWh)**	**Corresponding Demand Savings (MW)**
2017	89.8	23.4
2018	119.8	31.6
2019	149.7	39.9
2020	179.7	49.2
2021	209.2	58.4
2022	238.8	67.7
2023	268.4	77.0
2024	297.8	86.1
2025	327.0	95.3
2026	356.3	104.4
2027	385.3	113.5
2028	414.4	121.9
2029	443.3	130.3
2030	472.0	138.6
2031	500.7	146.9

The Morgan/Cadmus DSM Study included an evaluation of the Minnesota annual energy savings goal of 1.5%, and assessed the likelihood of reaching that goal based on several variables, including such factors as the saturation of various measures, the impact of building standards and codes, measure cost-effectiveness, etc. As discussed below, the results from the 2014 Morgan/Cadmus DSM Study indicate an expected DSM reduction over the resource planning period that is substantially less than the CIP policy goal. Based on the study results, the Minnesota Members will need additional reductions, above the cost-effective level of investment, to meet the 1.5% reduction each year.

3.3. DSM Implementation Activities

3.3.1. DSM Task Force

The MRES Board of Directors appointed a 16-member DSM Task Force in 2006. DSM Task Force members are selected from among all MRES Member communities to reflect the diversity among Members. The Task Force provides local input and expertise to guide MRES in the development of energy efficiency and demand response programs designed to achieve the savings identified in the DSM potential studies. The DSM Task Force has provided valuable input to the MRES Board of Directors to inform its decisions to achieve more robust energy efficiency and demand reduction. Specifically, the DSM Task Force provides ongoing evaluation and recommendations for:

- Wholesale Rate Structure
- Implementation of Energy Efficiency Incentive Programs
- Implementation of Marketing and Promotion Programs
- Providing Member Assistance and Program Administration
- Utilization of Evaluation, Measurement, and Verification Strategies
- Implementation of a Coordinated Demand Response Program
- Implementation of an Advanced Metering Infrastructure Program

The contributions of the member representatives of the DSM Task Force help to ensure that MRES energy efficiency and conservation programs meet the unique needs of the municipal utilities that make up MRES.

3.3.2. Wholesale Rate Structure Changes

The MRES Board of Directors, in its roles as the regulatory authority for the agency, reviews and approves rates on an annual basis. In 2011, the demand rate was modified to reflect seasonal cost differences, with higher charges during the summer and winter seasons and a lower rate during the spring and fall seasons. This new rate structure replaced a declining block rate structure, and provides distinct rate signals to create an economic incentive for MRES Members to manage their wholesale purchasing patterns. This change to the wholesale demand rate creates an economic incentive for Members to pursue energy efficiency and demand reduction, particularly during the summer and winter seasons. MRES charges the same energy rate throughout the year.

While those changes were implemented in 2011, MRES continues to evaluate its wholesale rate structure to assess whether it adequately and effectively implements policy objectives to recover the cost of services and, at the same time, provide appropriate signals to manage future demand. The MRES Board of Directors recently engaged a consultant to conduct a wholesale rate study. That study is expected to be completed in August 2016 so that it is available to inform the Board of Directors as they conduct their annual rate review.

3.3.3. Development of a Portfolio of Energy Efficiency Incentive Programs

Over the years, MRES has developed a comprehensive portfolio of energy efficiency incentives for all types of customers served by its Member municipal utilities. Currently, the following programs are offered to commercial and industrial customers in MRES Member communities:

- Commercial Refrigeration
- Compressed Air System Efficiency
- Custom Incentives for Businesses
- Food Service for Businesses
- Heating and Cooling for Businesses
- Lighting, New Construction
- Lighting, Existing Construction Retrofits
- New Construction Design Review
- Pump and Variable Frequency Drives
- Specialty Measures for Businesses
- Targeted Audits (including school audits, industrial audits, and retro-commissioning studies)

MRES offers the following residential incentive programs in Member communities:

- ENERGY STAR® Product rebates (variety of appliances and equipment)
- Residential Lighting Program
- Residential Heating and Cooling Program
- Air Conditioner Tune-up Program
- Quality Install Cooling Program
- Programmable Thermostats
- Appliance Turn-in (Recycling) Program

MRES continues to investigate new technologies and energy-saving opportunities on an annual basis to further develop and expand its portfolio of energy efficiency programs.

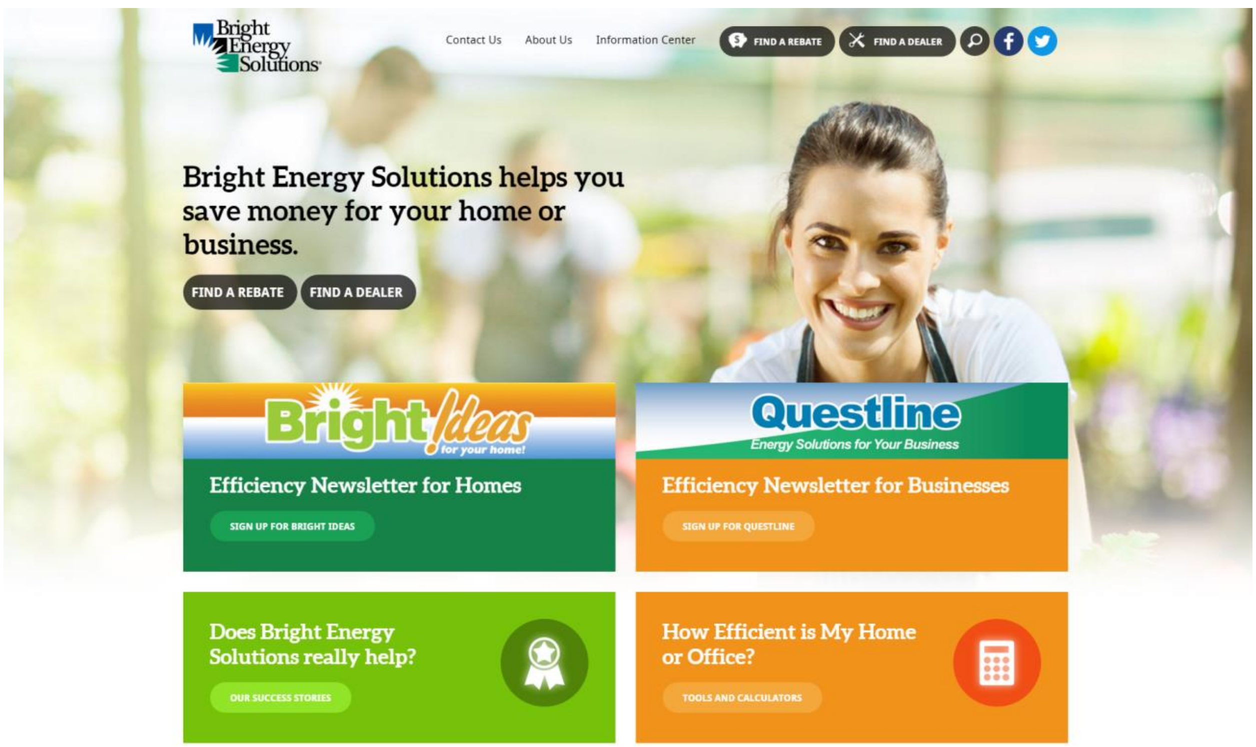
Individual MRES Members may participate in some or all of the incentive programs, depending on the energy efficiency opportunities specific to their customer base. In 2015, 57 MRES Members were participating in the energy efficiency programs, including all Minnesota Members.

3.3.4. Marketing and Promotion

To make its DSM programs successful, MRES and its Members maintain a deliberate and targeted education and marketing campaign to make customers aware of the benefits of energy efficiency. In order to provide a cohesive presence across all MRES Member communities in four states, the programs have all been branded with the Bright Energy Solutions® (BES) program name.

A comprehensive BES website, redesigned in 2015, provides easy access to program descriptions, brochures, online application forms, energy tips, and energy news.[19] The website also contains tools that customers can use to determine if their homes or businesses need energy improvements (on-line energy audits), and calculators to estimate energy savings and determine the best type of equipment to purchase. The website also includes a Home Energy Yardstick for customers to compare their home's energy usage with others across the country and get recommendations for improvement.

Figure 3-1: Bright Energy Solutions website home page



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[19] *See* http://www.brightenergysolutions.com.

To assist Members with their marketing and promotional efforts, the BES marketing plan contains strategies for promoting BES to internal Member utility employees to ensure that Members are aware of the latest program offerings, and the technical details of program offerings. In addition, the BES marketing plan also targets external audiences, including customers, trade allies, retailers, and the community at large. These education strategies are complemented by a variety of printable and electronic materials that MRES provides each month that can be easily customized by each Member for use in their local efforts to promote DSM by their retail customers.

A key strategy of the BES programs is to engage the assistance of “trade allies” — those retailers, vendors, suppliers, and distributors who are influential in the purchasing decisions of customers. MRES uses many avenues to inform and educate trade allies, and to encourage their participation and use of the BES incentive programs. These include group gatherings, one-on-one meetings, direct mailings, and electronic communications, as well as a dedicated section on the BES website for trade allies. In 2015, MRES also conducted a number of training seminars specifically for HVAC dealers to teach them how to perform a “quality installation” of air conditioning and heat pump equipment to ensure that the equipment is properly sized based on the most current efficiency standards and performing as designed.

3.3.5. Member Assistance and Program Administration

DSM program implementation requires detailed and consistent administration to ensure success. To assist MRES Members with the added administrative work required by the BES program, including marketing, implementation and verification, MRES has eleven full-time employees dedicated to energy services work, along with an administrative assistant who works part-time on energy efficiency issues. These employees are located throughout the four-state area to provide personal attention to Members and their customers in their area. The energy services staff delivers implementation assistance to educate customers and trade allies, provide cost/benefit analyses, help with purchasing decisions, and help customers complete rebate applications.

In addition to in-house staffing, MRES has also engaged a full-time equivalent consultant in the capacity of “Energy Advisor III” to assist with commercial and industrial audits and to evaluate custom projects. MRES also works with several additional consultants to provide occasional program development and implementation assistance.

3.3.6. Evaluation, Measurement, and Verification

A significant component of DSM program administration is evaluation, measurement, and verification (EM&V) of each specific program deployment. MRES tracks, measures, and verifies savings results throughout the implementation process to assure that efficiency projects are accurately reported. For example, random inspections are conducted on 5% to 10% of all commercial and industrial projects. Also, all custom projects and projects that have a potential incentive of $10,000 or more must obtain preapproval, and submit to both pre- and post-implementation inspections. In the event that new or unfamiliar equipment or technology is installed, MRES also conducts third party engineering reviews. Projects that have potential savings of 1 million kWh or more are reviewed by a third party engineering firm and are typically pre- and post-metered, in addition to both preapproval and inspections.

Many of the BES programs were developed as "prescriptive" programs, meaning that there is a specified incentive and deemed kW and kWh savings for each efficiency measure. MRES uses the Minnesota Technical Resource Manual provided by the Minnesota Department of Commerce, Division of Energy Resources for deemed savings for its prescriptive programs. For prescriptive measures that are not contained in the Technical Resource Manual, and for verification of custom savings calculations, MRES relies on the expertise of the engineering team at Franklin Energy of Port Washington, Wisconsin.

The accurate tracking and reporting of energy savings is vital to using DSM as a power supply resource. MRES commissioned Touchstone Systems Inc.,[20] to develop a thoroughly detailed tracking software program that MRES has branded BESTraK. BESTraK has the ability to verify that residential equipment meets the qualifications of the BES program by utilizing databases from ENERGY STAR® and the Air Conditioning, Heating, and Refrigeration Institute. BESTraK also records and tracks customer data, vendor data, incentives, kW and kWh savings, and payment information. Members have on-line access to BESTraK to directly input data. The BESTraK software can summarize information by MRES Member, by state, or by program. MRES uses these sophisticated capabilities to evaluate the cost-effectiveness of each BES program.

[20] TouchStone Systems, Inc., develops and offers state of the art information systems to the utility industry to address growing needs in marketing and conservation program administration. It is based in Birmingham, Michigan, and is not affiliated with Touchstone Energy.

3.3.7. Coordinated Demand Response Program

Thirteen of the MRES Member municipal utilities operate their own direct load control systems to reduce the peak demands on their systems and to help make efficient use of their power supply. In 2015, these Members achieved a peak load reduction of approximately 15.9 MW.

To encourage additional Members to utilize direct load control as a peak reduction tool and to assist Members with the cost, resources, and expertise needed to run a direct load control system, MRES initiated a Coordinated Demand Response (CDR) program in 2010. The CDR program design provides a defined technology platform, with a centralized load control server and software. The central equipment is owned, operated, and maintained by MRES, and is used to send control signals to equipment in homes and businesses in Member communities. Each Member is responsible for the investment, operation, and maintenance of the equipment within their community. MRES operates the CDR program to minimize the costs to each participating Member, and further encourage Members to manage their peak demand. The CDR program provides Members the opportunity to realize the benefits of direct load control without the need to add staff for monitoring and operating the system or making direct investment in an entire system.

The CDR program originally offered direct load control over powerline carrier technology. As radio frequency (RF) mesh technology advanced, MRES moved new participants to the more reliable RF mesh systems. This enables the Member communities to add smart meters and utilize two-way communications between the utility and the participating customers, leveraging wise investments on behalf of their customer-owners. One of the major benefits is that the CDR program allows Members to build on the infrastructure to automatically read electric and water meters whenever each individual community deploys Advanced Metering Infrastructure (AMI, also referred to as “smart meters”). The data collected creates the opportunity for each Member utility to pursue smart grid related services such as advanced meter reading, remote connect/disconnect, customer portal and outage management.

Currently ten MRES Members are participating in the CDR program, with four of those participants utilizing AMI. Demand savings are currently estimated at 2.0 MW for the summer season. MRES actively encourages additional Members to participate in the CDR program. The program goals, currently being proposed for MRES Board consideration, are to have fifteen CDR Members by 2018 and twenty CDR Members by 2020 controlling 26 MW of load.

The CDR results to date generally represent Members that historically operated their own load management systems and are now participating in the MRES CDR program. Thus, the effects of historical CDR results are implicitly included in the load forecasts. Potential additional effects of DSM and CIP on the loads, including incremental future CDR program effects, are calculated separately from the load forecasts to enable load and DSM forecasting to be separately evaluated. This is further explained below.

3.4. Energy and Demand Savings Results

MRES and its Members have steadily moved forward with energy efficiency efforts to implement the savings goals identified by the DSM Potential Studies, and to comply with state CIP objectives under Minnesota Statutes § 216B.241, subd. 1c, and Iowa Code 476.6(15)(c). The historical results for programs incented by MRES are as follows:

Table 3-2
MRES-Wide DSM Savings

	Energy Savings (million kWh)	Demand Savings (MW)
Year	**Actual**	**Actual**
2008	6.2	1.6
2009	16.5	3.7
2010	26.5	5.3
2011	29.8	6.1
2012	24.3	5.2
2013	28.2	6.1
2014	32.9	6.2

3.5. 2014 DSM Potential Study

As part of its ongoing efforts, MRES commissioned the Morgan/Cadmus DSM Study to calculate the DSM potential in the membership. The final report for the study was completed in October 2014 and is included in Appendix H. This study identified the 1) Technical Potential; 2) Economic Potential; 3) Achievable Potential; and 4) Program Potential for MRES DSM.

1) The Technical Potential assumes all technically feasible energy efficiency measures can be implemented, regardless of their costs or market barriers. The goal is to identify measures that are technically feasible.

2) The Economic Potential represents a subset of Technical Potential measures that meet cost-effectiveness criteria, based on avoided supply costs of MRES of delivering electricity and avoided line losses. The avoided costs were based on the capital cost of adding a new simple-cycle combustion turbine, and the energy cost from the MISO Locational Marginal Price market price for electricity at the MINN hub. The goal is to identify which technically possible measures are cost effective.

3) The Achievable Potential represents the portion of Economic Potential assumed reasonably achievable over the planning horizon, given both budgetary constraints and market barriers that may impede customer participation. The objective is to identify the level of customer acceptance that can be expected based on a reasonable level of intervention in the market to overcome adoption barriers.

4) Finally, the Program Potential represents the amount of annual energy and demand savings likely to be attained once the utility's specific program design components – such as measures offered, incentive structures, marketing efforts, and program budget constraints – have been taken into account. The Program Potential takes into account all program design components and budget constraints of the Achievable Potential.

The Morgan/Cadmus DSM Study determined the Program Potential based on program input from MRES, and using the DSMore® cost-benefit analysis tool. The result provides an estimate of the maximum amount of cost-effective and achievable savings, using the avoided cost assumptions provided.

The results from the Morgan/Cadmus DSM Study provided both energy and demand savings for the final year of the study (2039). (The study did not provide Technical, Economic, or Achievable Potential values for earlier years.) The amounts for the MRES Members in Minnesota are shown separately from the amounts for the other three states with MRES load in the following tables that summarize the forecasted energy and demand savings.

Table 3-3 DSM Study Results for 2039: Energy Savings (million kWh)			
	MN	**IA/ND/SD**	**Total**
2039 Energy Forecast	3,090.4	2,701.3	5,791.8
Technical Potential[1]	508.8	499.5	1,008.3
Economic Potential[1]	372.1	365.3	737.4
Achievable Potential[1]	227.0	222.8	449.8
Program Potential[1]	204.7	200.9	405.6
Direct Load Control	0.3	0.3	0.6
Program Potential +DLC	205.0	201.2	406.2
Percent Savings	6.63%	7.45%	7.01%

[1] Does not include savings from Direct Load Control.

Table 3-4 DSM Study Results for 2039: Non-Coincident Demand Savings (MW)			
	MN	**IA/ND/SD**	**Total**
2039 Demand Forecast	364.1	348.1	712.2
Technical Potential[1]	127.7	125.3	253.0
Economic Potential[1]	95.4	93.6	189.0
Achievable Potential[1]	86.4	84.8	171.2
Program Potential[1]	56.6	55.6	112.2
Direct Load Control	11.2	11.0	22.2
Program Potential +DLC	67.8	66.6	134.4
Percent Savings	18.63%	19.13%	18.88%

[1] Does not include savings from Direct Load Control.

Table 3-5 shows the Program Potential amounts by year for the IRP study period. The last column shows the coincident demand savings, which accounts for the portion of demand reduction expected during the MRES summer peak hour. Not all DSM technologies affect peak demand equally, so the amount of coincident demand reduction depends on the time of day and time of year as well as the relative mix of DSM programs active in a given year.

Table 3-5 Program Potential Results based on the Morgan/Cadmus DSM Study							
	Minnesota		IA/ND/SD		Total		
Year	Energy Savings (GWh)	Demand Savings (MW)	Energy Savings (GWh)	Demand Savings (MW)	Energy Savings (GWh)	Demand Savings (MW)	Coincident Demand Savings (MW)
2017	45.9	13.5	44.5	13.0	90.4	26.5	21.0
2018	61.5	18.2	59.5	17.6	121.0	35.7	28.3
2019	76.7	22.9	74.4	22.2	151.1	45.1	35.6
2020	90.7	27.5	87.9	26.6	178.5	54.1	42.8
2021	104.4	32.0	101.2	31.0	205.6	63.0	49.8
2022	118.0	36.5	114.5	35.4	232.5	71.9	56.8
2023	131.5	40.9	127.7	39.7	259.2	80.6	63.8
2024	144.9	45.3	140.9	44.0	285.8	89.3	70.6
2025	158.2	49.7	154.0	48.3	312.2	98.0	77.5
2026	171.5	54.0	167.1	52.6	338.6	106.6	84.3
2027	184.7	58.3	180.1	56.8	364.8	115.1	91.1
2028	186.5	59.1	182.0	57.7	368.5	116.9	92.5
2029	188.2	60.0	183.9	58.6	372.1	118.6	93.9
2030	189.8	60.8	185.8	59.5	375.7	120.2	95.2
2031	191.5	61.6	187.7	60.3	379.2	121.9	96.5

3.6. DSM Potential Used in this IRP

For the Base Case, it is assumed that a) the MRES municipal utility Members will achieve the full DSM Program Potential savings, plus b) the Minnesota Members will achieve an additional incremental amount of savings needed to meet the full 1.5% per year energy savings target of the state CIP requirements.

The Program Potential amounts are from the 2014 Morgan/Cadmus DSM Study, as estimated at the time of the MRES peak. These Base Case amounts are summarized in Table 3-6.

Table 3-6 DSM Base Case Reduction Amounts						
Year	**Expected DSM Case**		**Additional Minnesota amounts to meet 1.5% CIP**		**Total Base Case**	
	Energy Savings (GWh)	**Coincident Demand Savings (MW)**	**Energy Savings (GWh)**	**Coincident Demand Savings (MW)**	**Energy Savings (GWh)**	**Coincident Demand Savings (MW)**
2017	90.4	21.0	43.9	10.2	134.3	31.1
2018	121.0	28.3	58.3	13.6	179.3	41.9
2019	151.1	35.6	73.0	17.2	224.1	52.8
2020	178.5	42.8	89.0	21.3	267.5	64.1
2021	205.6	49.8	104.8	25.4	310.4	75.2
2022	232.5	56.8	120.8	29.5	353.3	86.3
2023	259.2	63.8	136.9	33.7	396.1	97.4
2024	285.8	70.6	152.9	37.8	438.7	108.4
2025	312.2	77.5	168.8	41.9	481.0	119.4
2026	338.6	84.3	184.8	46.0	523.4	130.3
2027	364.8	91.1	200.6	50.1	565.4	141.2
2028	368.5	92.5	227.9	57.2	596.4	149.7
2029	372.1	93.9	255.1	64.4	627.3	158.2
2030	375.7	95.2	282.2	71.5	657.9	166.7
2031	379.2	96.5	309.2	78.7	688.4	175.2

As can be seen by comparing this table to Table 3-5, the savings amounts in the Base Case are significantly higher than the DSM Program Potential amounts. The impact is illustrated in the Expected DSM alternative sensitivity cases, in which only the amounts that are feasible under the Program Potential calculations performed in the Morgan/Cadmus DSM Study are included, as calculated at the time of the MRES peak. Those amounts appear in the three rightmost columns of Table 3-5 (below the heading “Total”).

In the following step, the values in Table 3-6 were then divided between the two RTO regions – MISO and SPP – in which MRES Members are located, as each region is considered separately in the next section. These calculations are shown in Table 3-7 for SPP and Table 3-8 for MISO. Only three Minnesota Members (Luverne, Madison, and Moorhead) are included in the SPP region.

Table 3-7 DSM Reduction Amounts – SPP Region Only						
Year	**Expected DSM Case (See Table 3-6)**		**Additional Minnesota amounts to meet 1.5% CIP***		**Total Base Case***	
	Energy Savings (GWh)	**Coincident Demand Savings (MW)**	**Energy Savings (GWh)**	**Coincident Demand Savings (MW)**	**Energy Savings (GWh)**	**Coincident Demand Savings (MW)**
2017	49.2	11.4	12.3	2.9	61.5	14.3
2018	65.9	15.4	16.5	3.8	82.4	19.2
2019	82.4	19.4	20.7	4.9	103.1	24.3
2020	97.5	23.3	25.3	6.1	122.7	29.4
2021	112.3	27.2	29.8	7.2	142.2	34.4
2022	127.1	31.1	34.5	8.4	161.6	39.5
2023	141.8	34.9	39.1	9.6	181.0	44.5
2024	156.4	38.7	43.8	10.8	200.2	49.5
2025	171.0	42.4	48.4	12.0	219.4	54.5
2026	185.4	46.2	53.1	13.2	238.6	59.4
2027	199.9	49.9	57.8	14.4	257.7	64.3
2028	201.9	50.7	65.2	16.4	267.1	67.0
2029	204.0	51.4	72.5	18.3	276.5	69.7
2030	205.9	52.2	79.8	20.2	285.7	72.4
2031	207.9	52.9	87.0	22.2	294.9	75.1

* Amounts are slightly lower or higher in the Low and High Load Forecast scenarios.

Table 3-8 DSM Reduction Amounts – MISO Region Only						
Year	**Expected DSM Case (See Table 3-6)**		**Additional Minnesota amounts to meet 1.5% CIP***		**Total Base Case***	
	Energy Savings (GWh)	**Coincident Demand Savings (MW)**	**Energy Savings (GWh)**	**Coincident Demand Savings (MW)**	**Energy Savings (GWh)**	**Coincident Demand Savings (MW)**
2017	41.2	9.6	31.6	7.3	72.8	16.9
2018	55.1	12.9	41.8	9.8	96.9	22.6
2019	68.7	16.2	52.3	12.3	121.0	28.5
2020	81.1	19.4	63.7	15.3	144.8	34.7
2021	93.3	22.6	75.0	18.2	168.3	40.8
2022	105.4	25.8	86.4	21.1	191.7	46.9
2023	117.4	28.9	97.8	24.0	215.2	52.9
2024	129.4	32.0	109.1	27.0	238.4	58.9
2025	141.3	35.1	120.3	29.9	261.6	64.9
2026	153.1	38.1	131.7	32.8	284.8	70.9
2027	164.9	41.2	142.8	35.7	307.8	76.8
2028	166.6	41.8	162.7	40.8	329.3	82.6
2029	168.2	42.4	182.6	46.1	350.8	88.5
2030	169.7	43.0	202.4	51.3	372.2	94.3
2031	171.3	43.6	222.2	56.6	393.4	100.2

* Amounts are slightly lower or higher in the Low and High Load Forecast scenarios.

4. MRES Load Forecasts

MRES created load forecasts for the total load of each of its S-1 Members, as well as for Atlantic and Pella, Iowa. The MRES load forecasting methodology is described in Appendices E and F. Detailed results for each Minnesota Member are included in Appendix G. These are forecasts of expected loads assuming normal weather, before any effects of future DSM programs or CIP reduction efforts.

Many Members have some level of DSM already in place due to their previous efforts. The effects of these historical DSM efforts are implicitly included in the load forecasts. Potential additional DSM and CIP effects on the loads, including future CDR and BES program effects, are calculated separately from the load forecasts to enable load and DSM forecasting to be separately evaluated on an ongoing basis. Those variables are discussed later in this chapter.

Most MRES Members have two power suppliers: WAPA and MRES. Although the projection of the total load of a Member community is not affected by the source of power supply, it is necessary for planning purposes to understand the amount of load that will be provided by WAPA and the amount provided by MRES. The individual Member load forecasts include step decreases of 1% of the WAPA allocations after 2020 and 2030 based on the contract delivery schedules in place. The MRES portion of the load increases by the same amount.

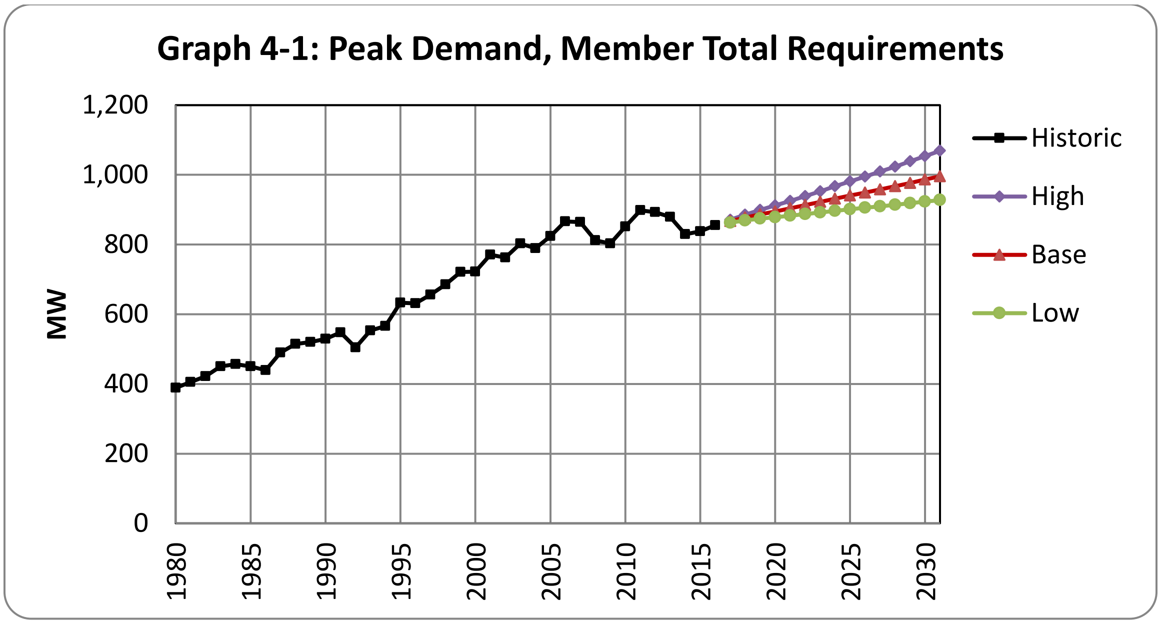
The total loads for the 57 S-1 Members plus the total loads of Atlantic and Pella are forecasted to reach 855.5 MW in the summer of 2016. This compares to an all-time historic peak of 898 MW in the summer of 2011. These loads are forecasted to reach 995.7 MW in the summer of 2031 in the Base forecast. Below are graphs of the total historic and forecast load, in terms of annual peak demand and annual energy requirements.

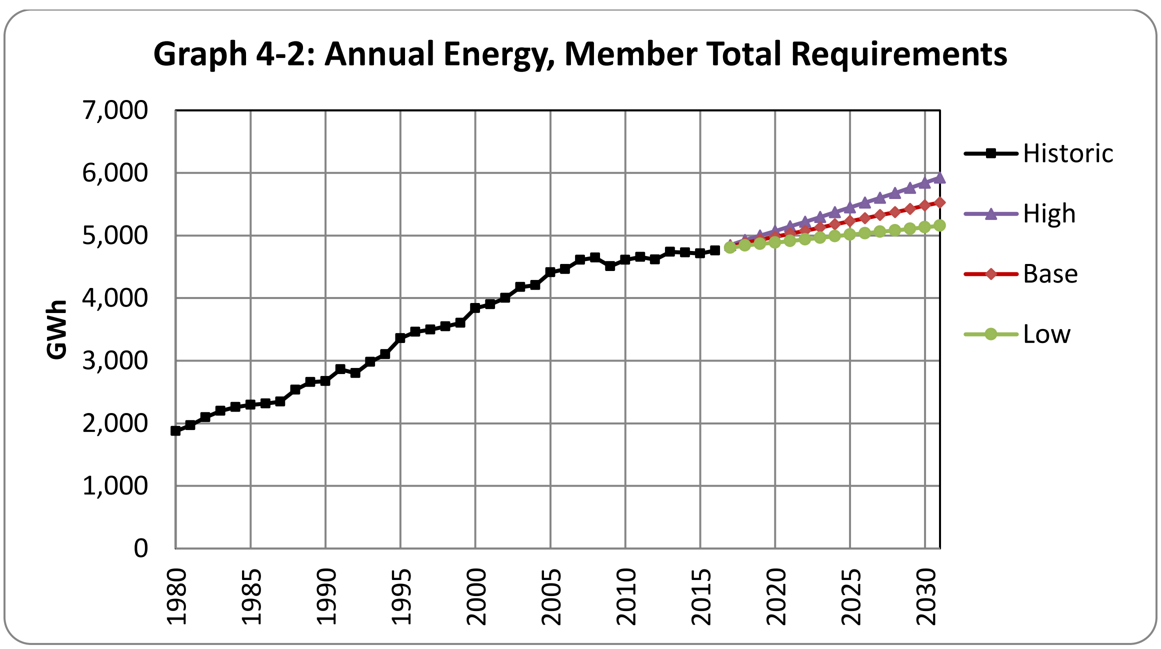
- The Atlantic load is included in these initial graphs because the amount provided by MRES depends on the total load forecast of the city. MRES supplies the needs above what Atlantic receives from its other current suppliers. The impact of the other suppliers is netted out in section 4.3.2 below.

- For Pella, MRES supplies the full requirements for the city. Pella’s peak demand requirements are forecasted to increase from 42.9 MW in 2017 to 50.4 MW in 2031.

- The Hutchinson contractual amount of 25 MW is not included in the initial graphs, since that sale is not affected by MRES load forecasting. Hutchinson is also a MISO member and is responsible for all of its power supply requirements other than the 25 MW contract from MRES. The impact of the Hutchinson 25 MW sale is reflected later in section 4.3.4 below.

Graphs 4-1 and 4-2 show the load forecast totals for the base, low-, and high-growth forecasts.





4.1. Dividing Requirements by RTO

The peak demand and annual energy shown in Graphs 4-1 and 4-2 are the amounts delivered at the load points by MISO and SPP. Each RTO requires its members to own or contract for capacity over and above the peak demand amounts (planning reserve capacity) to provide for transmission losses and reliable operation under varying conditions.

Because MRES has Member loads within both the MISO and SPP market areas, it is subject to two different procedures for calculating its planning reserve capacity needs. Thus, the total capacity obligations for each area are calculated separately and then the combined total is presented below.

4.1.1. Members in Each Market Region

Overall, there are 27 Members, representing about half of the MRES energy sales, located within the MISO market area. The remaining 33 Members are located within SPP. Most MRES and WAPA generation resources are within SPP.

Of the 24 Members located in Minnesota, 21 are in MISO and three are within SPP. The three Minnesota Members in SPP are Luverne, Madison, and Moorhead.

Two Members in MISO (Cavalier and Northwood, ND) have "grandfathered" transmission agreements which allow MRES to deliver energy to them from SPP without incurring MISO loss and congestion charges. MRES retained transmission across SPP for their loads to serve this energy, and receives credit in MISO for importing two MW of WAPA capacity from SPP. MRES must still meet any remaining capacity requirements for the Cavalier and Northwood loads using resources within MISO.

4.1.2. Cogeneration and Backup Service

There is one existing MRES Member community that has a cogeneration facility. It is associated with the American Crystal Sugar plant in Moorhead, Minnesota, which is in SPP. There is an agreement in place between Moorhead and the plant for backup service. The plant produces the bulk of its own energy supply.

MRES provides backup station service energy to the Fibrominn LLC power plant near Benson, Minnesota, which is in MISO.

For both loads, historic purchases have been small and future purchases are not expected to occur over the summer peak. No load forecast adjustments were made for those loads.

A large customer in Marshall, Minnesota, which is in MISO, has expressed interest in developing a cogeneration facility. The city has provided information and met with the customer. No further developments have occurred after many months of consideration by the customer.

To date, MRES has not found any additional interest in developing cogeneration or combined heat and power (CHP) facilities in the Member service areas. For that reason, no load forecast adjustment was made for cogeneration or backup service.

4.2. SPP Load Forecasts and Adjustments

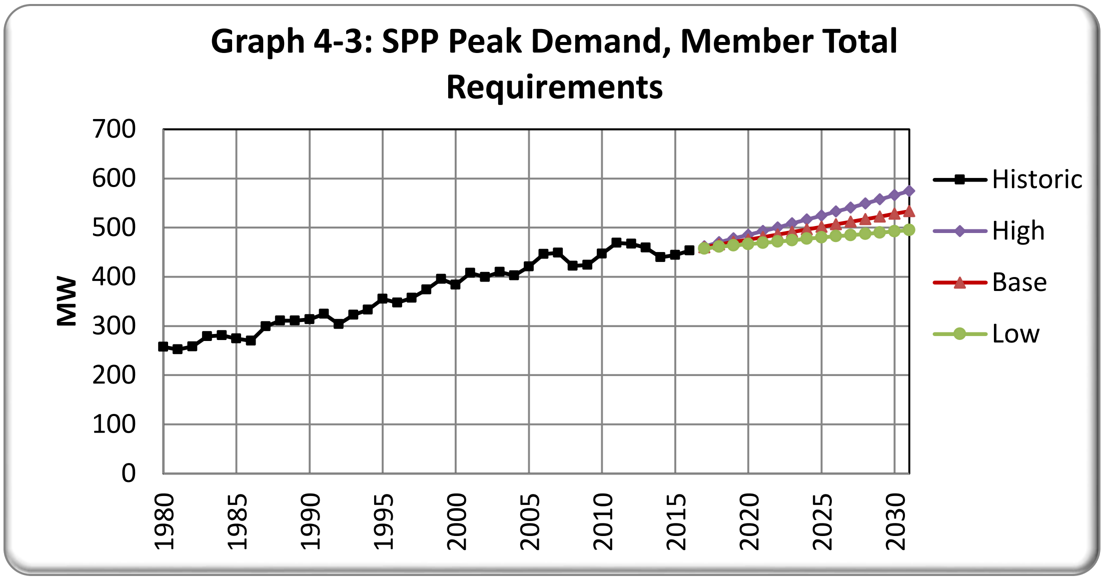
The total load forecasts of the MRES Members were shown in Graphs 4-1 and 4-2 above. In order to determine the amount of MRES planning reserve capacity required for the SPP region, the following steps were followed in sequence:

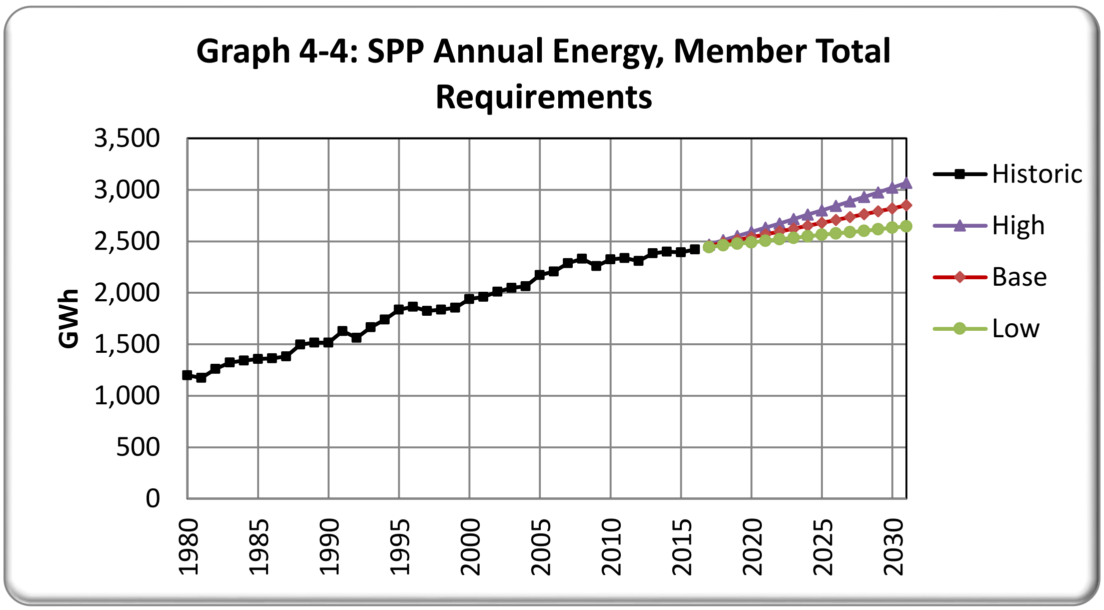
1) The MRES total load forecast was obtained for the Members in the SPP region only.
2) Then, the WAPA power supply was subtracted from the total SPP loads to determine the MRES capacity requirement. WAPA is the market participant in SPP for their portion of the Member load, and thus MRES is not responsible for meeting the WAPA capacity requirement in this RTO.
3) Next, the amount of the MRES capacity requirement was adjusted for future DSM and CIP impacts.
4) Finally, the results were further adjusted for peak load coincidence and the SPP planning reserve requirement of 13.64%.

Each step is discussed in detail next.

4.2.1. Total Load in SPP

To begin the process to determine the amount of MRES planning reserve capacity ultimately required for the SPP region, the total load in SPP, also referred to as the Member SPP Total Requirements, was established. Graphs 4-3 and 4-4 show the forecasts for total load of all of the Members in the SPP region.

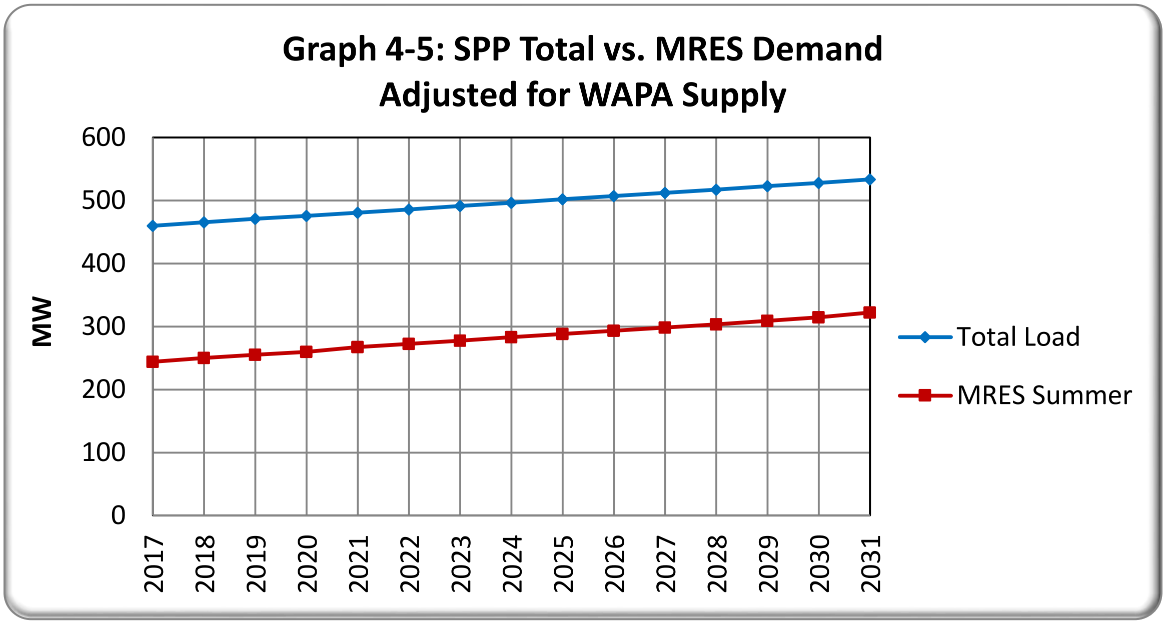


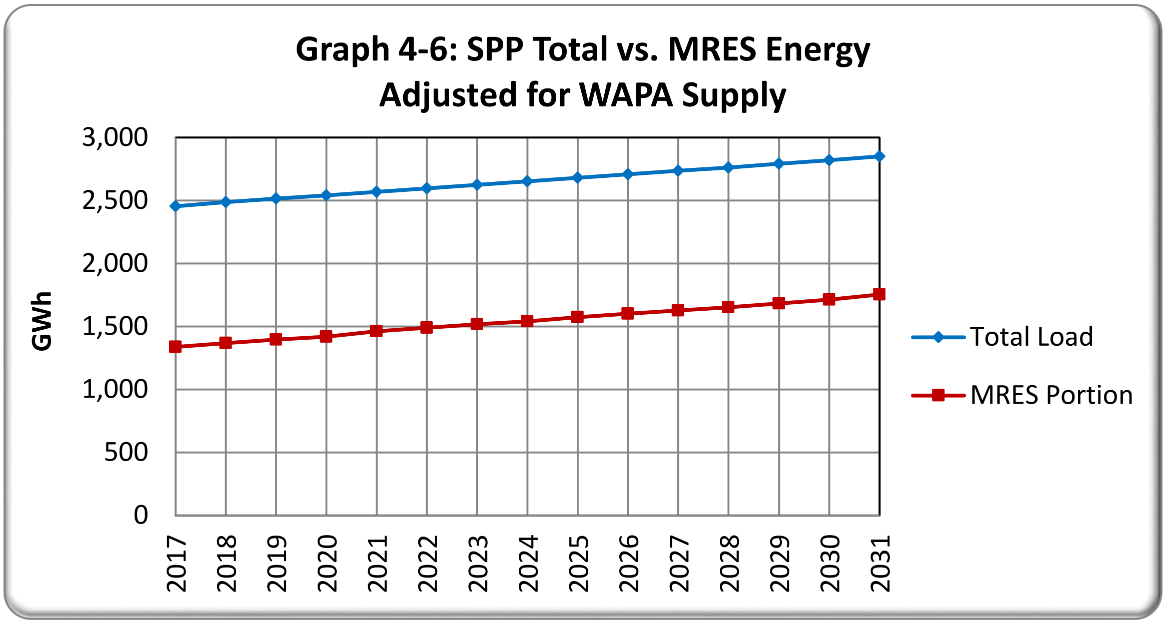


4.2.2. SPP Load Adjustment to identify MRES load responsibility

While the forecasts predict the total load of the S-1 Members, in SPP MRES supplies only the portion of the S-1 Member load over and above that supplied by WAPA. Thus, an additional step is required to remove the amount supplied by WAPA to determine the amount of the Member SPP Total Requirements that is the responsibility of MRES. Graphs 4-5 and 4-6 show the MRES responsibility for supply as a portion of the base load forecast after subtracting the portion of the load that WAPA will supply.

From the base forecast results, the overall SPP Member growth rate (total energy of the SPP Members) is 1.07% per year from 2017 through 2031. During that same time frame, the growth rate of the MRES portion of the load is 1.95% per year. The MRES portion grows faster than the total because the WAPA power supply is a fixed amount (and reduces by 1% at the end of 2020 and 2030). Thus, when Member load growth is at a rate of 1.07%, and the WAPA supply is fixed and/or declining, it causes the MRES responsibility to provide Members' power supply to increase at a faster rate. Stated another way, the WAPA supply serves a fixed portion of the Members' load and does not increase; any increases or decreases in total load are reflected entirely in the MRES power supply portion, referred to as supplemental power supply, *i.e.* MRES Demand or MRES Energy.

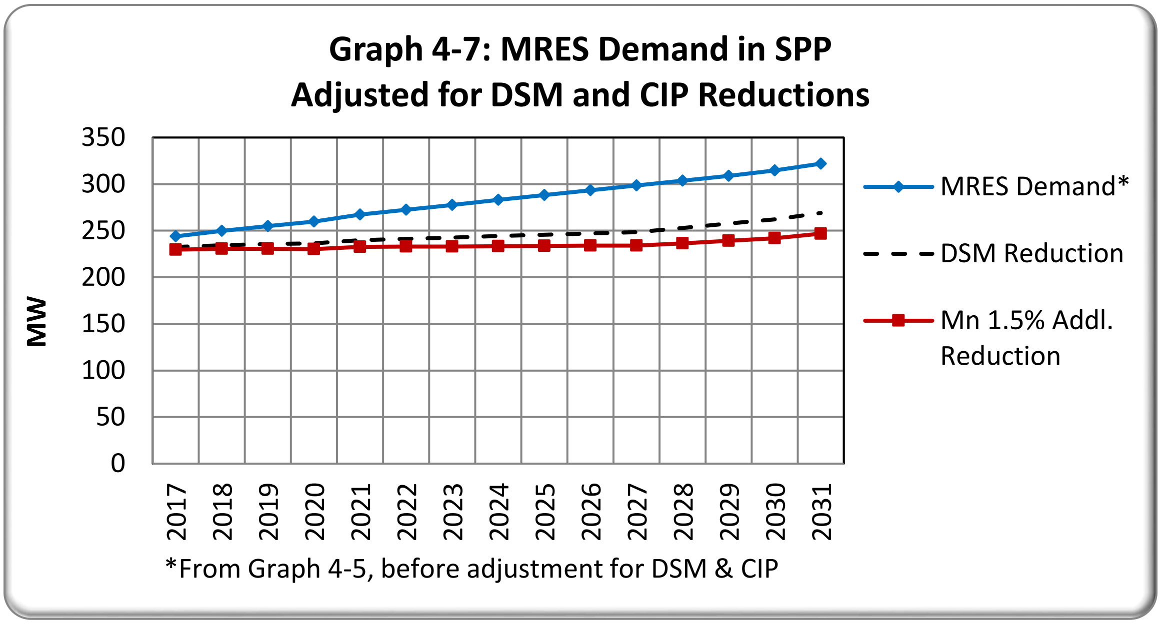


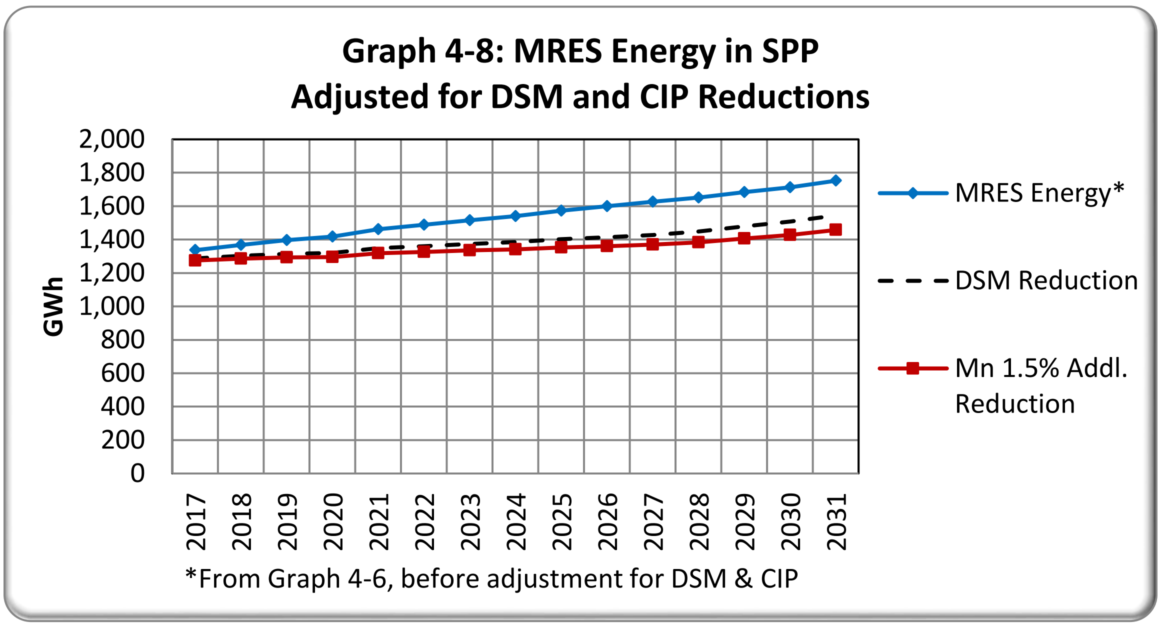


4.2.3. MRES Portion of SPP Load Adjusted for DSM and CIP

Next, the MRES portion of the load is adjusted to reflect the reductions resulting from DSM in the amounts described earlier. These total DSM reductions, for most sensitivity cases in the resource plan, are the sum of a) the full DSM Market Potential savings (*i.e* assuming the full amount is actually met), plus b) an incremental amount of savings by Minnesota Members needed to equal the entire 1.5% per year for CIP requirements. (For select sensitivity cases discussed later, the incremental savings assumption was less than the full DSM Market Potential and/or the full 1.5% CIP requirement.)

Each component of the DSM reduction is shown separately in the graphs below. The graphs illustrate the MRES portion of the Members' SPP load, then the "DSM Reduction" is calculated by subtracting the Market Potential Study amounts, and finally, "Mn 1.5% Addl Reduction" is calculated by subtracting the full 1.5% CIP from the difference between the MRES Member load and the DSM Reduction. The red line labeled "Addl Mn 1.5%" is the final load forecast values for the combined reductions to the MRES SPP load. Note the slight increase in net load requirements for MRES over time in SPP in the final result.





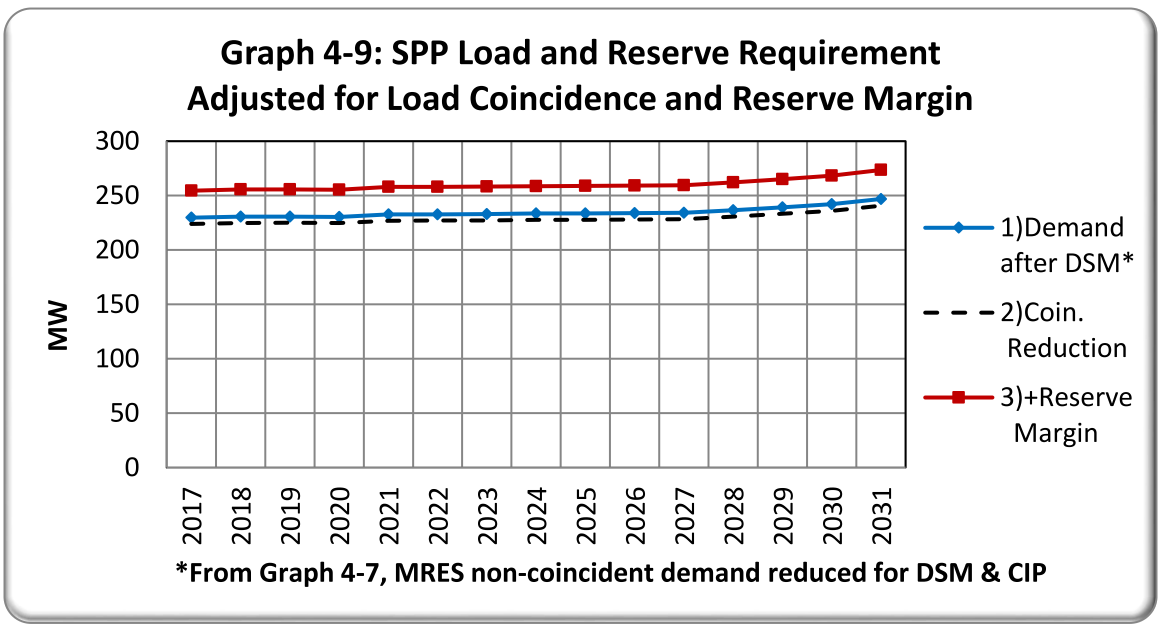
4.2.4. SPP Load Coincidence and Planning Reserves

The demand values calculated so far use the individual Member peaks ("non-coincident peaks") which are recorded at the times of the monthly peaks for each of the 33 Members in SPP. The coincident MRES peak, which is the combined peak of all MRES Members in SPP at the single highest load hour in the season, will be slightly less than sum of the non-coincident peaks. The coincidence factor is used to account for this difference.

For the load in SPP, the coincidence factor is 97.5%, based on historic load from 2010 through 2014. This represents the difference between the non-coincident total demand and the coincident demand at the time of the combined MRES peak, which has historically occurred in July. The impact on projected MRES SPP Demand was about 6 MW each year from 2017 through 2031. Coincidence has no effect on energy values.

Finally, SPP has a 13.64% planning reserve requirement. This resource plan assumes the 13.64% planning reserve requirement for all MRES load in SPP. The planning reserve requirement is calculated based on the 50/50 load forecast at the load node, meaning there is a 50% chance of the load forecast being either high or low in any year. This is consistent with the MRES Base forecast methodology. The calculation estimates the requirements during the coincident peak hour of all MRES load in SPP, for each 12-month period beginning each October 1.

Graph 4-9 shows the forecasted MRES load in SPP from graph 4-7 after all adjustments, including the additions required for the SPP planning reserves and with the reduction for load coincidence within SPP.



4.3. MISO Load Forecast and Adjustments

When determining the MRES planning reserve capacity requirement in MISO, there is an important difference compared to the procedure in SPP. In MISO, MRES is the market participant representing the full requirements of its Member loads (except for Hutchinson and

Atlantic), including load served via their WAPA power supply. (MISO allows only a single entity to serve load, while SPP allows for a maximum of two entities to serve a single load.) In effect this makes MRES the full-requirements supplier for those Members. In return, MRES receives credit in MISO for the energy and capacity delivered by WAPA on behalf of the 27 MRES MISO Members.

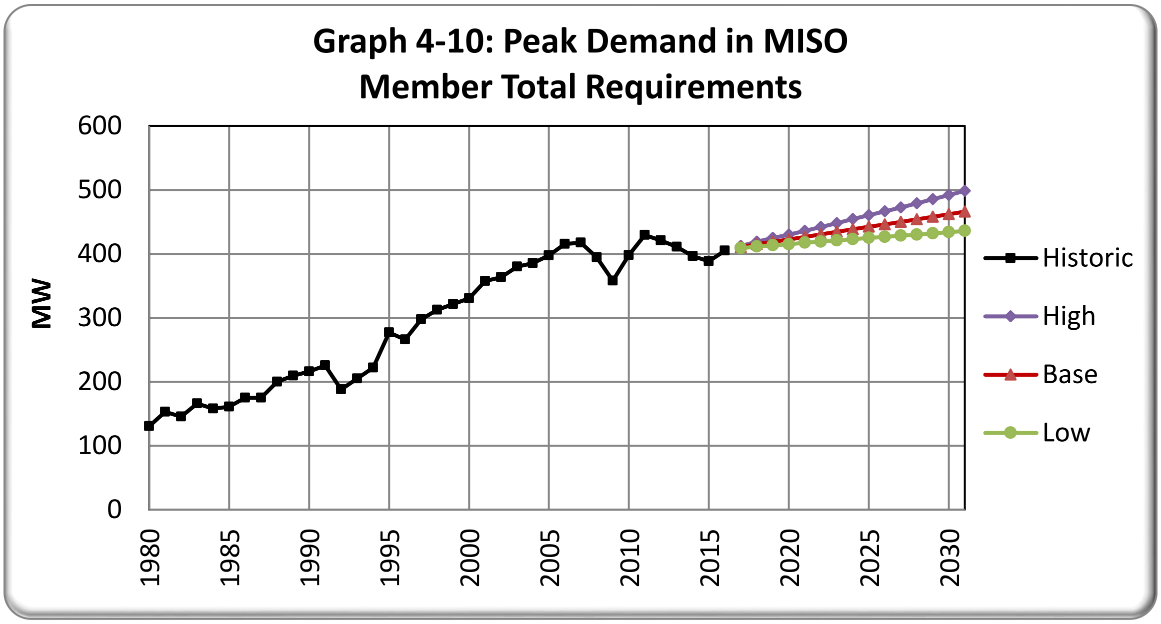
The total load forecasts of the MRES Members were shown in Graphs 4-1 and 4-2 above. In order to determine the amount of MRES planning reserve capacity required for the MISO region, the following steps were followed in sequence:

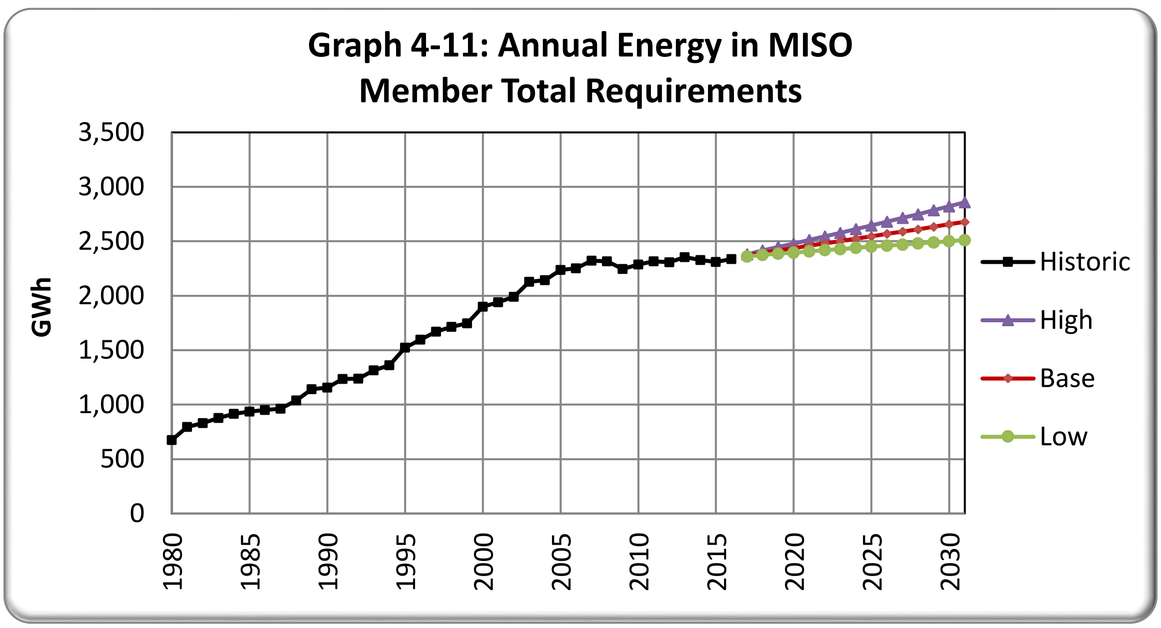
1) The MRES total load forecast was obtained for the Members in the MISO region only. In MISO, MRES is responsible for planning reserve capacity on the WAPA portion of the load as well, so that load is not subtracted from the total.
2) Any portion of the Atlantic, IA capacity requirement that is not the responsibility of MRES was then subtracted.
3) Next, the MRES capacity requirement (including the remaining Atlantic requirement) was adjusted for future DSM and CIP impacts.
4) The results were then increased to account for the 25 MW sale to Hutchinson, MN. (This sale is not impacted by DSM or CIP.)
5) The results were further adjusted for peak load coincidence, losses, and the MISO planning reserve requirement.
6) Finally, the result is adjusted for the MISO planning reserves. WAPA supplies capacity towards the MISO planning reserve obligation for its share of the load, but due to its transmission arrangements MRES is not able to receive credit for all that WAPA capacity in MISO. MRES incurs an additional amount of planning reserve requirement in MISO due to this shortfall of WAPA capacity.

Each step is discussed next.

4.3.1. Total Load in MISO

To begin the process to determine the ultimate amount of MRES planning reserve capacity required for the MISO region, the total load in MISO was established. Graphs 4-10 and 4-11 show the forecasts for total load for all of the S-1 Power Supply Members in the MISO region. In addition, the forecasts also include the communities of Atlantic and Pella, Iowa, which have Non S-1 power supply agreements with MRES. This combined amount of the S-1 Member requirements and the Atlantic and Pella requirements is referred to as total load in MISO, or Member MISO Total Requirements.

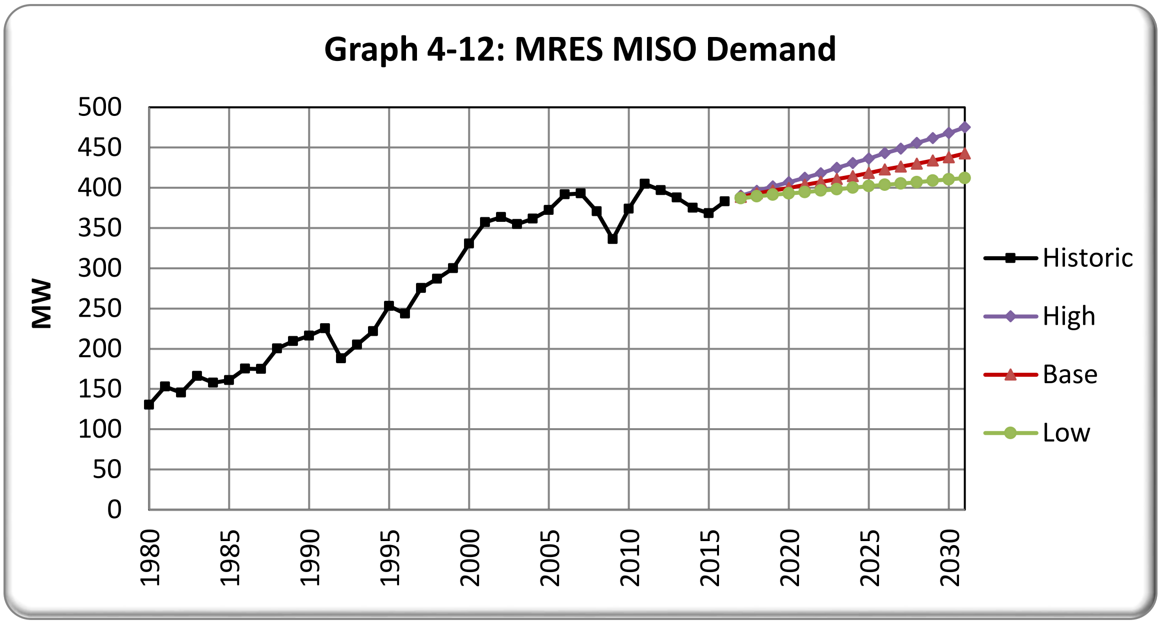


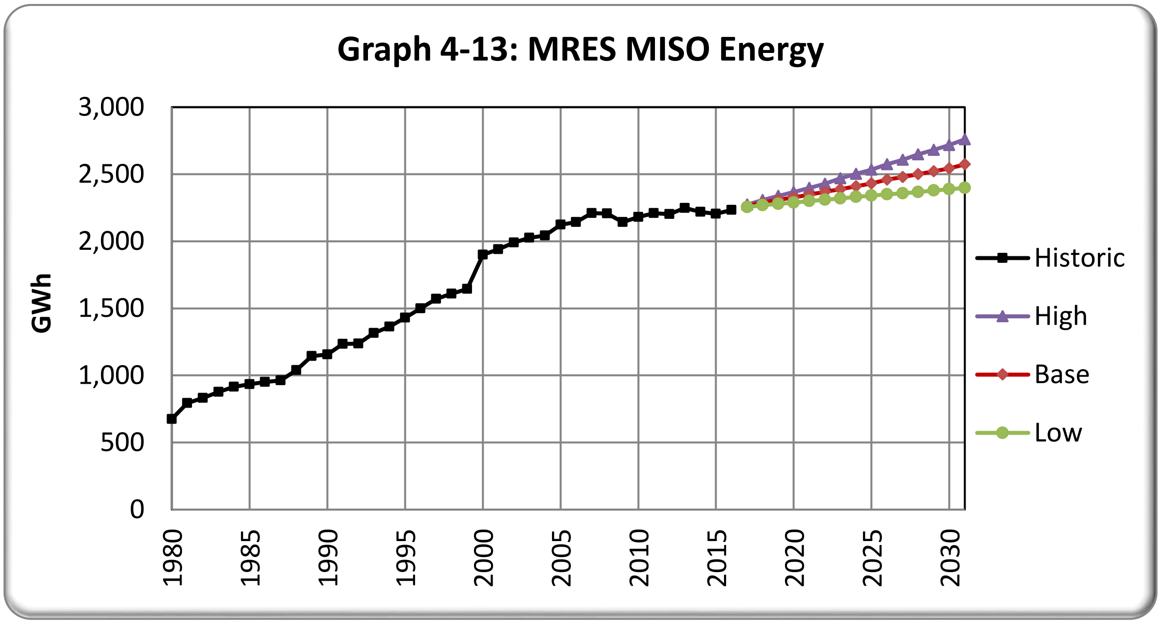


4.3.2. MISO Load Adjustment to identify MRES load responsibility

Any portion of the Atlantic requirements that is supplied by other resources owned by Atlantic is removed in the second step. The MRES responsibility for Atlantic is established once a year and is always a single whole MW amount for every hour of the year. Based on the current forecast, MRES will supply 1 MW of capacity and energy in all hours through 2025, then the amount will increase to 3 MW by 2031. MRES is not responsible for any other portion of the Atlantic load forecast.

The resulting MRES responsibility is shown on the next two graphs. From the Base forecast results, the overall growth rate (total energy of the MISO Members) is 0.92 percent per year from 2017 through 2031.

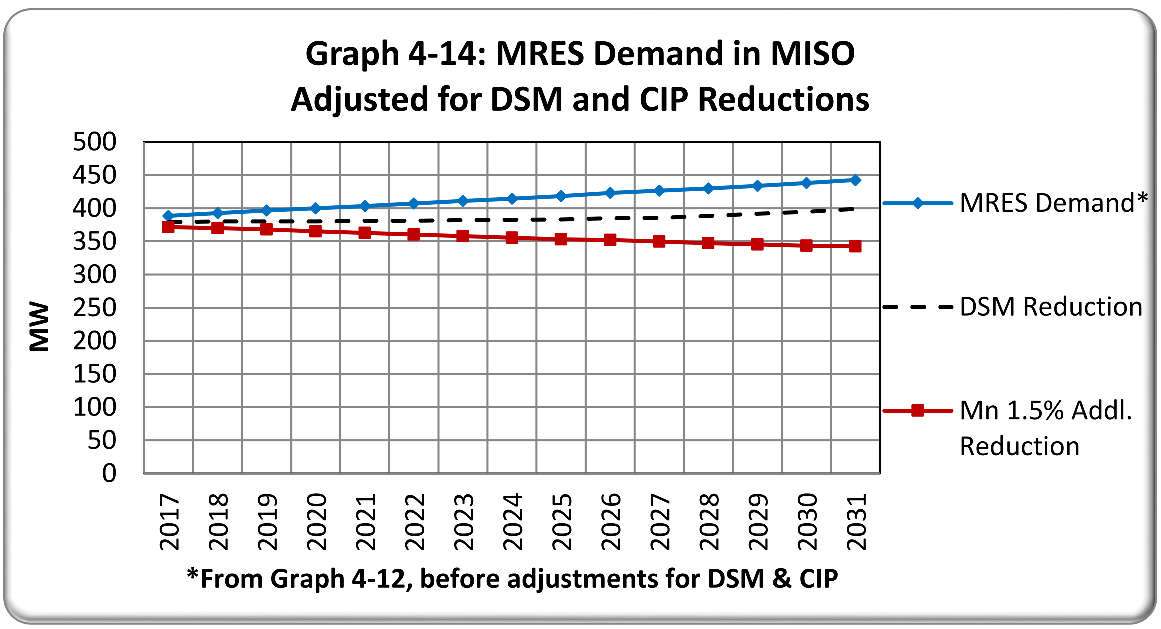


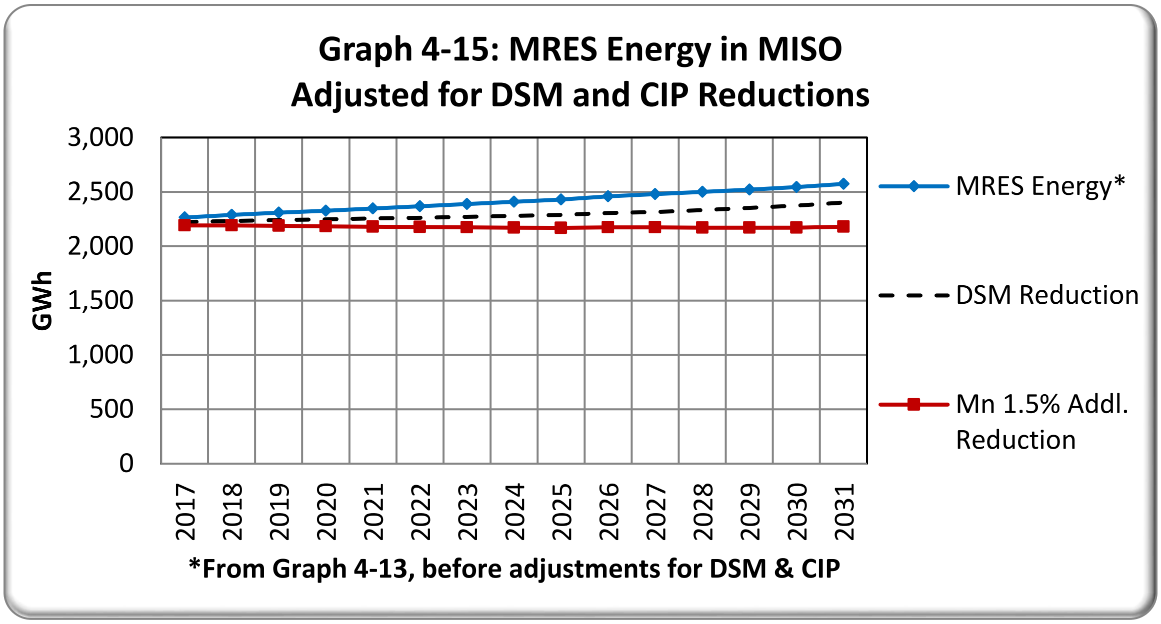


4.3.3. MRES Load in MISO Adjusted for DSM and CIP

As in SPP, the next adjustment to the load forecasts is based on DSM and CIP reductions. These total DSM reductions, for most sensitivity cases in the resource plan, are the sum of a) the full DSM Market Potential savings (*i.e* assuming the full amount is actually met), plus b) an incremental amount of savings by Minnesota Members needed to equal the entire 1.5% per year for CIP requirements. Each component of the DSM reduction is shown separately in the graphs below. (For select sensitivity cases, the incremental savings assumption was less than the full 1.5% CIP requirement, as discussed later.)

Each component of the DSM reduction is shown separately in the graphs below. The graphs illustrate the MRES portion of the Members' MISO load, then the "DSM Reduction" is calculated by subtracting the Market Potential Study amounts, and finally, the full 1.5% CIP was subtracted from that result. The red line labeled "Addl Mn 1.5%" illustrates the final load forecast values for the combined reductions to the MRES MISO load. The adjusted base load forecast values based on the sum of the DSM and CIP reductions for the MRES load are shown in the graphs below. With the full 1.5% CIP assumption, there is a steady decrease in net load requirements for MRES over time in MISO.

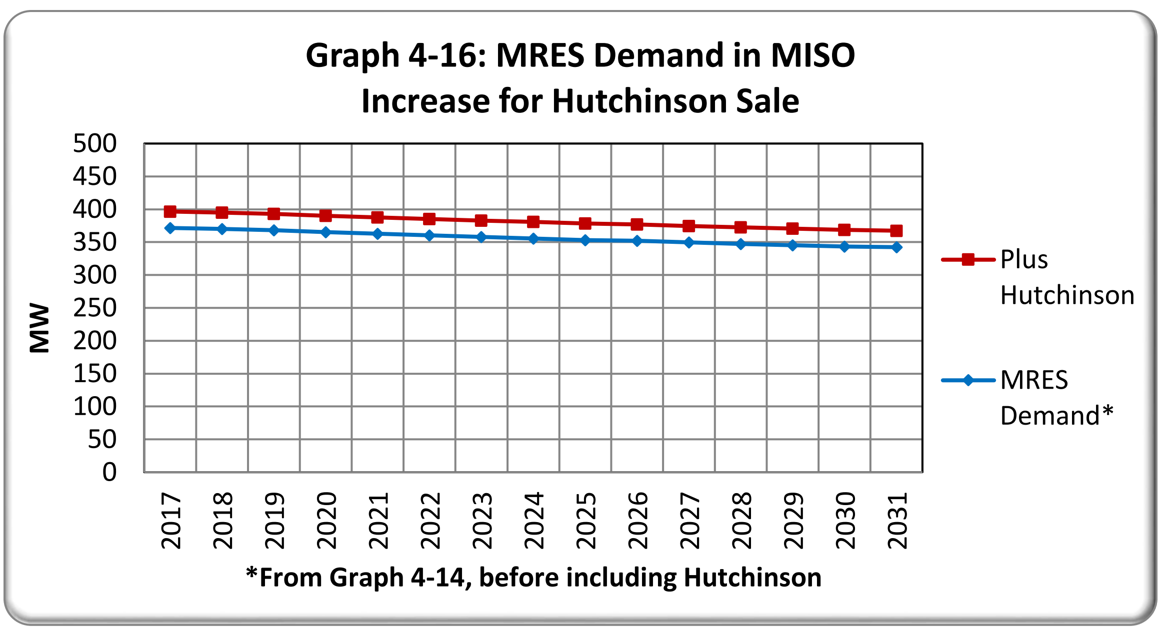


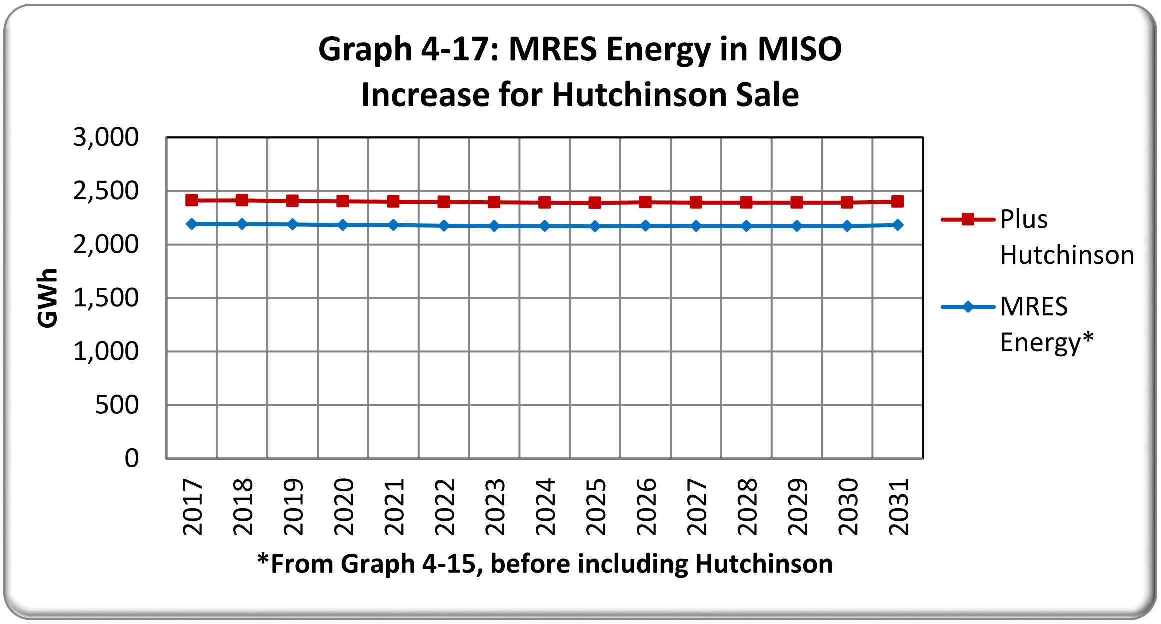


4.3.4. MISO Load Adjustment for Hutchinson Power Sale

Next, an adjustment to the load forecast was made to add the amount required under the Non S-1 long-term firm contract with the Hutchinson Utilities Commission. This contract obligates MRES to provide a fixed 25 MW of capacity and energy in all hours to Hutchinson; there are no adjustments to this amount based on changes in load.

The resulting MRES responsibility after the adjustment is shown on the next two graphs:





4.3.5. MISO Load Coincidence, Losses, and Planning Reserves

The adjustment of the load forecasts to account for coincidence, losses, and planning reserves in MISO involves more complexity than in SPP (where all MRES load is in a single transmission zone). The MISO Resource Adequacy Requirement (RAR) rules specify that adequate capacity be designated to meet the 50/50 load forecast at the load nodes, coincident with the summer MISO-wide peak, plus transmission losses (based on the transmission supplier area in which the load is located) and a Planning Reserve Margin (PRM).

Similar to the discussion above for SPP, the MISO demand values shown in the prior graphs use the individual Member peaks ("non-coincident peaks") which are recorded at the time of the monthly peak for each of the 27 Members in MISO. The coincident MRES peak, which is the peak of all the MISO Members at the time of the overall MISO-wide peak for the season, will be slightly less than the non-coincident peak. The coincidence factor is used to account for this difference.

In MISO, the peak load is required to be reported per transmission zone. Accordingly, the coincidence factor for load in MISO is based on the Members' respective transmission zone. Individual transmission zones exist for several MRES Members, as listed in the first several entries in Table 4-1 below; for Members in the Minnesota Power, Otter Tail Power, and Alliant West local balancing areas, each area represents a single transmission zone. Individual coincidence factors were calculated for each transmission zone, representing the difference between the non-coincident total demand of the Members in a zone and the coincident peak demand of those Members at the time of the overall MISO peak. These values are shown in Table 4-1, column three ("Coincidence Factor"). Coincidence has no effect on the energy values.

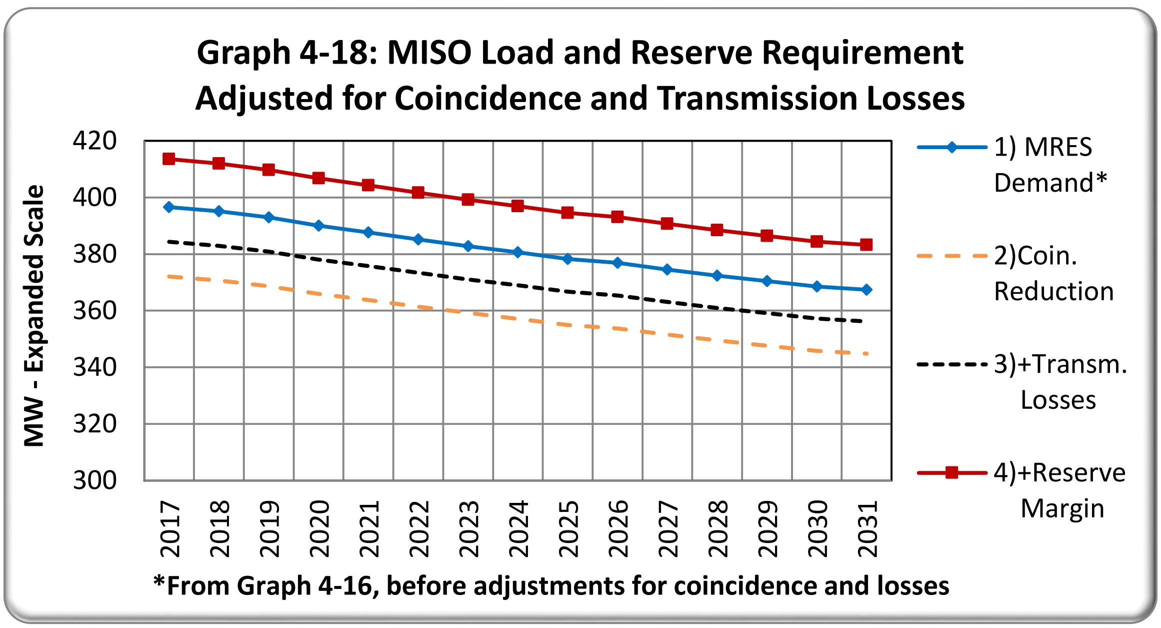
In addition, an adjustment to MRES Member loads in MISO is required to reflect the transmission losses in each transmission zone. The transmission loss percentages specific to each local balancing area are identified in column four of Table 4-1.

<table>
<tr><th colspan="5">Table 4-1
Coincidence Factors and Transmission Losses
Applied to MISO Load</th></tr>
<tr><th>Local Balancing Area</th><th colspan="2">Member Cities</th><th>Coincidence Factor</th><th>Transmission Losses</th></tr>
<tr><td>Northern States Power</td><td colspan="2">Melrose MN
Marshall MN
Sauk Centre MN
St James MN</td><td>91.0%
97.2%
90.8%
93.4%</td><td>2.7%</td></tr>
<tr><td>Otter Tail Power</td><td colspan="2">Cavalier ND
Hillsboro ND
Northwood ND</td><td>86.7%
84.9%
86.4%</td><td>3.3%</td></tr>
<tr><td>Mid-American Energy</td><td colspan="2">Atlantic IA
Pella IA</td><td>96.0%
93.4%</td><td>2.3%</td></tr>
<tr><td>Great River Energy</td><td colspan="2">Hutchinson MN</td><td>100%</td><td>1.5%</td></tr>
<tr><td>Minnesota Power</td><td>Staples MN</td><td>Wadena MN</td><td>92.1%</td><td>6.8%</td></tr>
<tr><td>Otter Tail Power</td><td>Alexandria MN
Barnesville MN
Benson MN
Breckenridge MN
Detroit Lakes MN</td><td>Elbow Lake MN
Henning MN
Lake Park MN
Ortonville MN
Big Stone City SD</td><td>90.8%</td><td>3.3%</td></tr>
<tr><td>Alliant West</td><td>Adrian MN
Jackson MN
Lakefield MN</td><td>Westbrook MN
Worthington MN</td><td>95.7%</td><td>2.1%</td></tr>
</table>

Following the reductions to reflect coincidence and the additions for transmission losses, the load forecasts were adjusted to reflect the PRM. The next table shows the historic PRM requirements in MISO for the years that the current methodology has been in place. MRES assumed a PRM requirement of 7.6% in all future years for the modeling done in this resource plan. This is applied to all MRES load in the MISO market area, including both the Atlantic and Hutchinson firm sale amounts.

Table 4-2 Historic MISO Planning Reserve Margin Requirements	
RAR Year (June – May)	**PRM Requirement**
2013-14	6.2%
2014-15	7.3%
2015-16	7.1%
2016-17	7.6%

The application of the coincidence factor results in the reduction for coincidence shown in Graph 4-18 below. Also shown are the increases for MISO transmission losses and reserve margin requirements. Given that the magnitude of the changes at this step is smaller, the MW scale has been expanded on Graph 4-18 to better show the detail.



4.3.6. WAPA Portion of Reserve Requirements

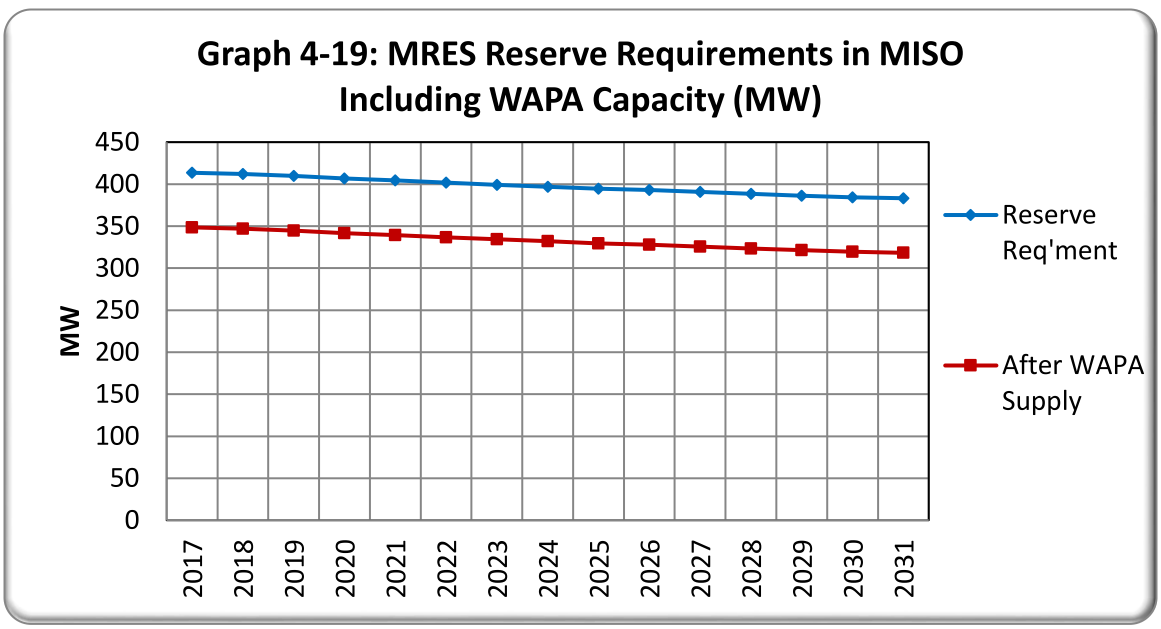
Finally, there is one other factor which increases the amount of capacity that MRES must supply in MISO. The MRES MISO Members also receive a portion of their power supply from WAPA, whose resources are outside of MISO.

In MISO, for any amount of capacity utilized to meet the RAR requirement, the utility must commit to a "must-offer" requirement, meaning an offer into the MISO day-ahead energy market must be made for every hour of the year in the amount of the designated capacity. For an external resource such as the WAPA capacity, this means a day-ahead transmission tag must be entered and approved for each hour in the amount of the capacity being designated.

The WAPA supply is provided using network service, which allows tags to be made only for the actual amount of load in any given hour. Higher values cannot be tagged in excess of the actual amount just to meet the must-offer requirement. Thus, WAPA has not been able to receive MISO Planning Reserve Credits (PRC) amounts for its full capacity. Rather, it receives PRC MW for only what can be served during the lowest hours of the year. MRES must supply the remaining capacity for the WAPA portion of its Members' load.

MRES receives approximately 65 MW of PRC capacity for the WAPA resources for MRES Members. That amount was used in the study for all future years.

Graph 4-19 shows the MISO reserve requirements based on the load forecast after all adjustments discussed above, including reductions for the DSM Potential Study and for meeting the full 1.5% CIP requirement in Minnesota. Also shown is the reduction due to PRC capacity supplied by WAPA for its portion of MRES MISO Members' load.



4.4. Generation Resources

This section shows the amounts of generation, either capacity or energy resources, that MRES has available to serve its Member loads. The generation details in the MISO and SPP market areas are presented separately below. Only MRES resources within the same RTO are utilized to meet Member planning reserve requirements in that RTO, with the exception of supply to Cavalier and Northwood as described in Subsection 4.1. No resources are expected to be retired during the timeframe of this resource plan (although the possible reduction in LRS capacity is studied later in some alternative sensitivity cases).

4.4.1. Generation Resources in SPP

The ratings for MRES generation resources available to serve its load in SPP are based on the SPP methodology for capacity. In the tables below, the lowest unit rating during June, July, or August is reported as the summer rating. The values shown are the 2015 summer ratings.

Generation capacity that may be used to meet the SPP reserve requirement is determined by the SPP generating equipment rating criteria, which includes the requirement for performing a generator verification run at least every three years.

Table 4-3

MRES Capacity Resources in SPP (MW)

Unit Description	**Summer Rating**
1. Base Load from LRS Unit 1: LRS is a coal-fired plant consisting of three units, located near Wheatland, Wyoming. MRES receives energy from LRS Unit 1. The other two units are currently connected to the western US electrical interconnection and are not physically capable of delivery to MRES. MRES receives 281 MW in 2016 and every third year thereafter; in all other years it receives 282 MW.	281.8
2. Exira Station: Exira is a three-unit, natural gas combustion turbine station, with oil-fired backup capability, located near Atlantic, Iowa. It provides peaking capacity for MRES.	140.0
3. Watertown Power Plant (WPP): This is an oil-fired combustion turbine located in Watertown, South Dakota. It provides peaking capacity for MRES.	45.9
4. Municipal Capacity in SPP: These are various units owned by several Member municipalities located within SPP and contracted to MRES. See Table 4-4 below for the list of these municipal capacity units. They provide peaking capacity for MRES.	28.1
Total MW Capacity:	**495.8 MW**

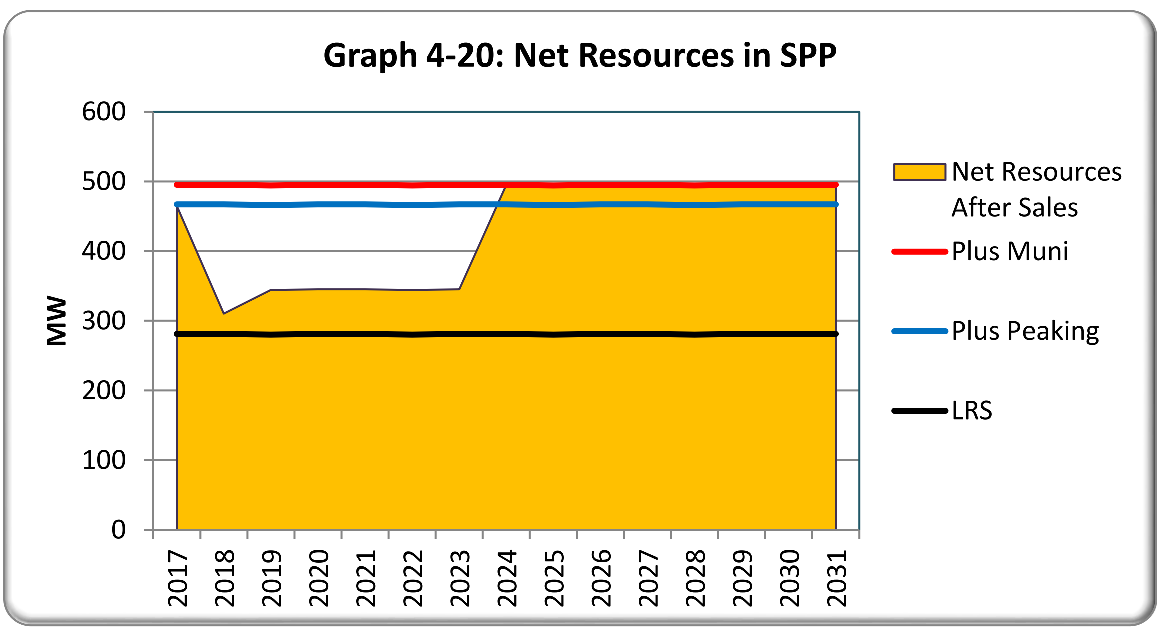
Table 4-4 MRES Municipal Capacity in SPP	
City	**Summer Rating**
Denison, IA	1.8
Lake Park, IA	4.0
Rock Rapids, IA	2.4
Luverne, MN	3.5
Moorhead, MN	10.3
Fort Pierre, SD	6.1
Total	**28.1**

The division of MRES power supply between the MISO and SPP markets results in a large surplus of generating capacity in the SPP region as compared to load. Since joining SPP, MRES has been marketing the surplus capacity to other utilities in the region. As a result, the following transactions are included in this resource plan as reductions in resource capacity in the SPP region:

- Sale to Northwestern Energy of 30 MW of capacity for 2017, and 35 MW for 2018.
- Sale to Basin Electric Power Cooperative of 150 MW of capacity for the six years of 2018 through 2023.

These transactions are for capacity rights only, for purposes of meeting the resource adequacy requirements in the region. They have no effect on the amount of energy that MRES may produce from its resources in SPP.

Graph 4-20 illustrates the MRES capacity resources in SPP during the planning period.



4.4.2. Generation Resources in MISO

The MISO methodology for calculating and crediting the capacity of resources is different than that in SPP. In measuring the capacity that accrues towards the MISO RAR, the utility first defines each unit's Installed Capability (ICAP) based on annual tests. MISO then discounts the ICAP value to account for historical or typical forced outage rates or other operational characteristics of similar units to obtain the Unforced Capability (UCAP) rating. Only the UCAP amount may accrue towards the RAR.

In MISO, each utility designates the amount of each unit it wishes to designate to meet RAR in each month by designating some or all of each unit's UCAP rating as Planning Resource Credits (PRC). Each PRC is equivalent to 1 MW of UCAP for one month. Any designated amount of a unit that clears the MISO auction must be offered each hour in the MISO day-ahead energy market, unless outages or de-rates are properly documented with MISO.

The tables below identify the ICAP based on the MISO annual unit verification run, as adjusted to summer peak conditions according to MISO procedures. The UCAP then discounts the rating for the forced outage rate for units of that type. Municipal capacity located behind the load meter point also receives a credit for the same transmission losses which had been added to load at that location. The values shown are the 2015 summer ratings.

Table 4-5

MRES Capacity Resources in MISO (MW)

Unit Description		**Summer Rating ICAP**	**Summer Rating UCAP**
1.	Municipal Capacity in MISO: These are various units owned by several Member municipalities located within MISO and contracted to MRES. See Table 4-6 below for the list of these municipal capacity units in MISO.	106.3	97.1
2.	Point Beach Nuclear Generation: Capacity from the 2011 agreement with WPPI Energy to obtain a share of the two Point Beach nuclear units. The amount of capacity is approximately 32.8 MW, reducing to 16.4 MW in 2030 (when the agreement for one of the units expires).	32.8	32.8
3.	Wind Capacity Credit in MISO: This credit is for various wind resources located within MISO and contracted to MRES. See Table 4-7 below for the list of these wind resources in MISO.	85.7	9.4
4.	Red Rock Hydro Project: Starting in 2018:	55.0	36.5
	Total MW Capacity:	**279.8**	**175.8**

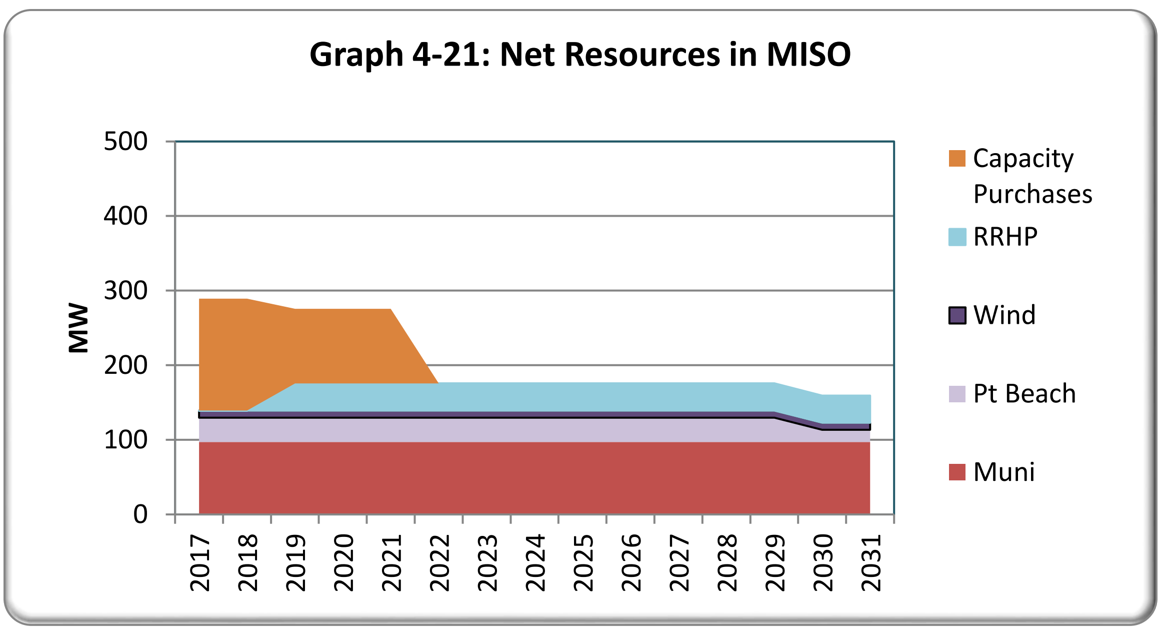
Table 4-6
MRES Municipal Capacity in MISO

City	Summer Rating	MISO UCAP
Pella, IA	25.6	22.4
Adrian, MN	2.0	1.8
Benson, MN	9.8	8.8
Detroit Lakes, MN	9.7	9.8
Lakefield, MN	3.0	2.7
Marshall, MN	16.0	15.7
Melrose, MN	8.2	7.3
Saint James, MN	12.0	10.7
Westbrook, MN	2.0	1.8
Worthington, MN	14.0	12.5
Hillsboro, ND	4.0	3.6
Total	**106.3**	**97.1**

Table 4-7 MRES Wind Capacity in MISO		
Wind Resource	**Rating (MW)**	**Capacity Credit (MW)**
Hancock Wind Project (IA)	3.3	0.0
Marshall Wind Farm (MN)	18.7	0.0
Odin Wind Farm (MN)	20.0	2.8
Rugby Wind Project (ND)	40.0	6.6
Worthington Wind Project (MN)	3.7	0.0
Total	**85.7**	**9.4**

Those wind units directly connected to a Member's distribution system, namely the Worthington wind units, are included in the capacity expansion modeling as a direct reduction of the Worthington load rather than as capacity resources. Any other wind resources produce energy which MRES sells into the MISO energy market. In some cases, capacity credit for wind cannot be obtained because no firm transmission arrangements are in place at this time.

As a minimum, enough wind is included in the resource plan models each year to meet the Minnesota Renewable Energy Standard (RES) requirements for all MRES load in Minnesota, including the firm load sale to Hutchinson, and the 10% goal by 2015 for the load in Iowa (assumed), North Dakota, and South Dakota. The MISO resources are depicted below in Graph 4-21.



The division of MRES power supply between the MISO and SPP markets results in a large deficit of generating capacity in the MISO region as compared to load. MRES has been seeking the purchase of capacity from other utilities in MISO. As a result, the following transactions are included in this resource plan as an increase in resource capacity in the MISO region:

- Purchase from GRE of 100 MW of capacity for the years 2017 and 2018.
- Purchase from Morgan Stanley of 50 MW of capacity for the years 2017 and 2018.
- Purchase from Morgan Stanley of 100 MW of capacity for the years 2019 through 2021.

As in SPP, these transactions are for capacity rights only, for purposes of meeting the resource adequacy requirements in the region. MRES does not receive energy under the capacity transactions.

4.5. Current Supply vs. Demand

The bifurcation of MRES capacity resources was caused by the division of MRES Members into two RTO markets and the decision not to purchase firm transmission capacity across SPP for delivering MRES resources into MISO.[21]

The graphs below illustrate MRES demand in comparison to supply resources, in both SPP and MISO. The final adjusted demand forecast for SPP and the net resources in SPP are graphed against one another in Graph 4-22. This illustrates that, when considering demand in comparison to current resources and transactions only, MRES has surplus capacity in all years in SPP. The numeric values are shown in Table 4-8.

A similar illustration for MISO is set forth in Graph 4-23. When considering current resources and transactions only, MRES is deficit in capacity in all years in MISO. The numeric values are shown in Table 4-9.

[21] The MRES Board of Directors chose to not purchase firm transmission capacity to deliver MRES resources from SPP into MISO because the financial price tag for acquiring the service would have caused a substantial annual increase in costs. However, two transmission reservations were continued for deliveries of MRES supply across SPP into MISO for Cavalier and Northwood, ND, due to their grandfathered MISO transmission agreements.

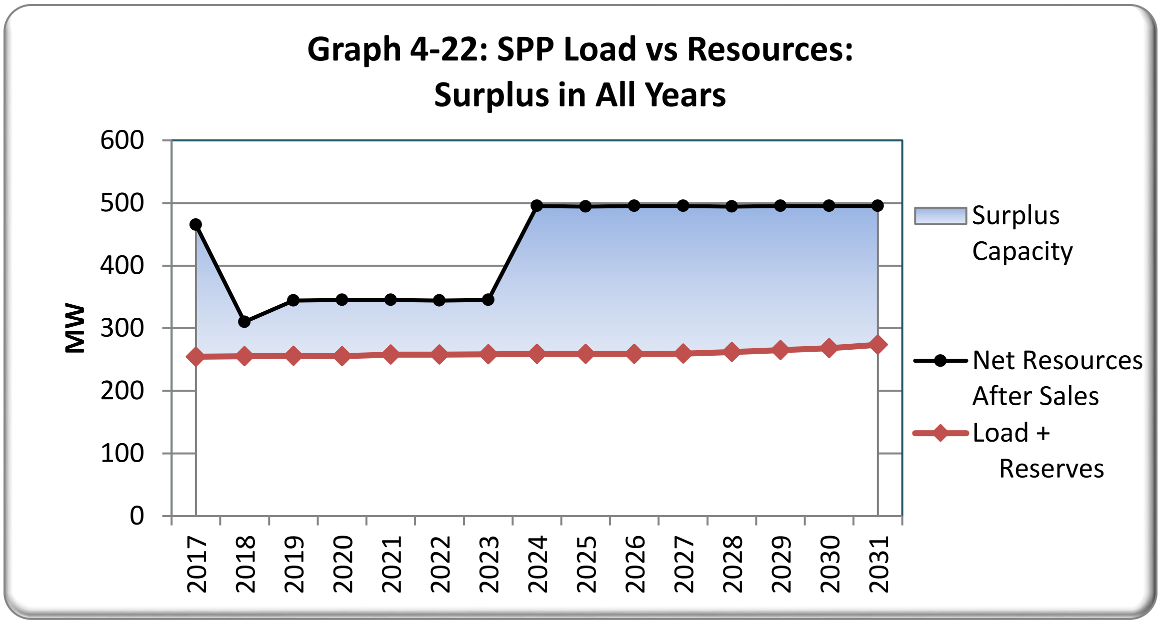


Table 4-8 SPP Requirements vs Resource Amounts (MW)			
Year	**Load Plus Reserve Requirement**	**Resources After Sales**	**Surplus Capacity**
2017	254.5	465	210.5
2018	255.5	311	55.5
2019	255.7	346	90.3
2020	255.3	346	90.7
2021	257.9	345	87.1
2022	258.0	346	88.0
2023	258.2	346	87.8
2024	258.7	496	237.3
2025	258.9	495	236.1
2026	259.1	496	236.9
2027	259.4	496	236.6
2028	262.0	496	234.0
2029	265.1	495	229.9
2030	268.2	496	227.8
2031	273.5	496	222.5

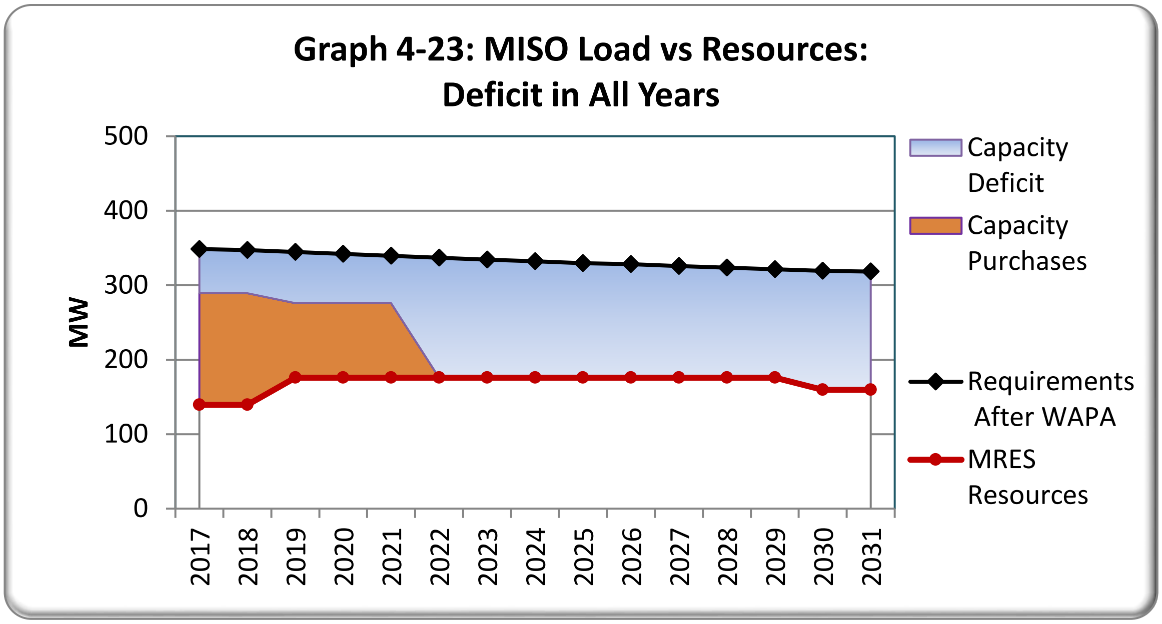


Table 4-9 MISO Requirements vs Resource Amounts (MW)			
Year	**Net Required After WAPA**	**Resources & Purchases**	**Capacity (Deficit)**
2017	348.1	289.3	(59)
2018	346.5	289.3	(57)
2019	344.3	275.8	(69)
2020	341.2	275.8	(65)
2021	338.9	275.8	(63)
2022	336.2	175.8	(160)
2023	333.8	175.8	(158)
2024	332.3	175.8	(157)
2025	329.8	175.8	(154)
2026	328.4	175.8	(153)
2027	326.0	175.8	(150)
2028	323.8	175.8	(148)
2029	321.7	175.8	(146)
2030	319.8	159.4	(160)
2031	318.7	159.4	(159)

MRES continues to pursue opportunities to purchase firm capacity in MISO.

To the extent MRES remains capacity deficit in each upcoming year, the deficiency must be purchased in the annual MISO capacity auction. The cost of such auction capacity could be very low, as it has been in recent years, or very high. It is the intent of MRES to increase its firm capacity in MISO over time to eliminate most or all of its annual capacity auction purchases. Specifically, the Red Rock Hydroelectric Project will become available in 2018, and capacity purchases have been made from GRE and Morgan Stanley for 2017 through 2021.

The remaining MISO capacity deficiency in the short term (2017 through 2021) is relatively small, approximately 60 to 70 MW. This limited amount of exposure to the capacity auction presents a manageable short-term cost risk and allows flexibility in the event of greater-than-anticipated reduction in demand. MRES actively manages its energy risk by evaluating whether to lock in additional bilateral capacity purchases or pay the auction price for this shortfall for every year. MRES has a formalized policy to manage such risks, and the implementation of that policy is subject to monthly review by its Risk Oversight Committee. The actual amount of shortfall will be affected by any load forecast error or the loss (or gain) of retail customers.

This resource plan assumes that new resources can be added (through ownership of new or purchase of existing capacity) to avoid all forecasted capacity deficits from 2022 forward. After 2021, the MISO deficit is approximately 160 MW.

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5. Plan Development

5.1. Goals of the Resource Plan

Minnesota Rule 7843.0500 establishes five factors to consider for the evaluation of a resource plan. The Commission considers the ability of the plan to

A. Maintain or improve the adequacy and reliability of utility service;
B. Keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
C. Minimize adverse socioeconomic effects and adverse effects upon the environment;
D. Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
E. Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Minn. R. 7843.0500, subp. 3. These factors are consistent with the MRES mission statement, so MRES has adopted these same factors into its goals for this plan, as presented below.

5.1.1. Study Goal 1: Maintain the Adequacy and Reliability of Power Supply

To meet the goal to maintain or improve power supply adequacy and reliability, load projections were developed for MRES Members, including the additional amounts required for SPP and MISO planning reserves. All existing resources were assumed to remain in operation through at least 2031.

Based on these criteria, using only existing resources, MRES is deficient in capacity in the MISO region in all years. In the SPP region, MRES has adequate capacity throughout the study period, although under some study conditions MRES would add renewable resources in the SPP region.

The purpose of this first study goal is to determine the lowest-cost, reliable plan to optimize the amount of resources, while meeting capacity requirements. It necessitates the evaluation of a variety of resources to meet identified capacity needs, including natural gas combined cycle (NGCC), combustion turbine (CT) units, wind turbines, and solar energy.

Because MRES is experiencing an immediate deficiency of capacity in MISO due to the recent integration into the SPP region, the study goal was adjusted to allow a transition period for the first five years. MRES has worked to reduce this deficiency by purchasing capacity on a year-by-year basis. Any remaining deficit in this transition period results in a purchase in the annual MISO capacity auction. The study models this by allowing one-year capacity purchases, priced at the MISO Cost of New Entry (CONE), to meet any capacity shortfall during the transition period. For 2022 and beyond the study does not allow year-by-year purchases to be used.

5.1.2. Study Goal 2: Keep Members' Wholesale Rates Competitive

The primary objective of this second goal is to minimize the overall long-term power supply costs to MRES Member communities and their consumer owners. Capacity expansion modeling was utilized to determine the least-cost resource mix (both demand-side and supply-side) under a number of different sensitivity cases. The analysis examined these resource combinations over the 2017 through 2031 timeframe. The primary focus of this goal is to minimize the overall capital and operational costs, including emissions costs, as well as other externality costs required for this filing.

To maintain consistency, each RTO area was studied separately.

5.1.3. Study Goal 3: Minimize Adverse Socioeconomic and Environmental Effects

As with past resource planning efforts, MRES analysis continues to include the evaluation of the economic impact that electric generation creates indirectly in terms of environmental and social effects that are not directly part of capital or operating expenses. This plan includes costs analyses regarding emissions of oxides of nitrogen (NO_x), particulates (PM_{10}), carbon monoxide (CO), lead (Pb), sulfur dioxide (SO_2), and carbon dioxide (CO_2). The sensitivity cases each applied Commission-approved environmental externality prices for NO_x, PM_{10}, CO, and Pb when computing the least-cost plan. The externality prices used, as escalated through the study period, are shown in Table 5-1 below:

Table 5-1 Externality Prices ($/Ton) High Values -- Within 200 Miles of Minnesota[1] Escalated at 3% Per Year				
Year	**NO_x**	**PM_{10}**	**CO**	**Pb**
2017	$162.71	$1,363.83	$0.66	$ 714.61
2018	$167.59	$1,404.75	$0.68	$ 736.05
2019	$172.62	$1,446.89	$0.70	$ 758.13
2020	$177.79	$1,490.30	$0.72	$ 780.87
2021	$183.13	$1,535.01	$0.74	$ 804.30
2022	$188.62	$1,581.06	$0.76	$ 828.43
2023	$194.28	$1,628.49	$0.78	$ 853.28
2024	$200.11	$1,677.34	$0.81	$ 878.88
2025	$206.11	$1,727.66	$0.83	$ 905.25
2026	$212.30	$1,779.49	$0.86	$ 932.40
2027	$218.66	$1,832.88	$0.88	$ 960.38
2028	$225.22	$1,887.86	$0.91	$ 989.19
2029	$231.98	$1,944.50	$0.93	$1,018.86
2030	$238.94	$2,002.83	$0.96	$1,049.43
2031	$246.11	$2,062.92	$0.99	$1,080.91

[1] "Notice of Updated Environmental Externality Values," *In re Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. §216B.2422, Subd.* 3, Minnesota Public Utilities Commission, Dockets No. E-999/CI-93-583 E-999/CI-00-1636, May 27, 2015

Also considered were the expected market costs for sulfur dioxide (SO_2) allowances. The allowance prices used for SO_2, as escalated through the study period, are shown here:

Table 5-2 SO_2 Allowance Prices ($/Ton)[1] Escalated at 3% Per Year	
Year	**SO_2**
2017	$ 8.49
2018	$ 8.74
2019	$ 9.00
2020	$ 9.27
2021	$ 9.55
2022	$ 9.84
2023	$10.13
2024	$10.44
2025	$10.75
2026	$11.07
2027	$11.40
2028	$11.75
2029	$12.10
2030	$12.46
2031	$12.83

[1] Based on high market bid of $8 for 2015 published by ICAP Energy on Nov. 18, 2015, with price escalation.

Various CO_2 emission cost values were explored, as discussed later. Those externalities and emission cost values were calculated using all MRES firm load. In addition, CO_2 analysis included several sensitivity cases by specifically using renewable wind and solar resources for energy to meet this study goal.

Another element key to the goal of minimizing adverse socioeconomic and environmental effects is the use of non-emitting resources to meet the renewable resource objectives established by the MRES Board of Directors. These goals include not only meeting the RES mandate in Minnesota, but also voluntarily meeting the goal to provide renewable energy in each Member state. MRES is committed to achieving the Minnesota RES benchmarks of supplying 17% of the energy served by MRES in the state with renewable energy by 2016, increasing to 20% by 2020, and 25% by 2025.

As indicated in its renewable energy compliance filings and the Commission's most recent Order Finding Utilities in Compliance,[22] MRES presently meets the renewable energy goals for its Minnesota load and has resources in place to meet it for the next several years.

In addition, the MRES Board of Directors is also committed to maintain adequate resources to supply at least 10% of its load in the other states with renewable resources. This commitment ensures that MRES will meet the voluntary goals established in both North Dakota and South Dakota to maintain 10% renewable resources in those states by 2015. Although Iowa does not have a statutory mandate or goal applicable to utilities that are not rate regulated, nonetheless, MRES also maintains renewable resources to ensure that 10% of its Iowa load is renewable as well.

A major component of minimizing environmental impacts of providing reliable and cost-effective power supply to MRES Members is to fully implement conservation and DSM. Like the power supply program, the MRES strategy to reduce consumption and delay the need to acquire additional resources is vital to achieving our planning goals. As described earlier, MRES commissioned the Morgan/Cadmus DSM Study to update MRES data on DSM potential. Those results were incorporated into this resource plan, and are used to guide the MRES Bright Energy Solutions program. MRES is undertaking efforts to implement cost-effective DSM measures throughout its membership. In addition, MRES is assisting its Minnesota Members in their efforts to meet the full CIP requirement, which includes DSM amounts in addition to what was found feasible in the study.

5.1.4. Study Goal 4: Enhance the Ability of MRES to Respond to Changes and Limit its Risks

This goal represents the last two factors established in Minnesota Rule 7843.0500, subp. 3, D-E, for evaluating a resource plan. To ensure that MRES is nimble enough as an organization to respond to industry changes and limit risks, the resource plan discusses and analyzes several of the potential changes and risks MRES could face. These risks, along with several other significant risks related to resource planning generally, are addressed in the sensitivity analyses described below.

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[22] *See* "Order Finding Utilities in Compliance with Minn. Stat. § 216B.1691," filed August 13, 2015, in Minnesota Public Utility Commission these three dockets: *In the Matter of Commission Consideration and Determination on Compliance with Renewable Energy Standards,* Docket No. E-999/M-14-237; *In the Matter of a Renewable Energy Certificate Retirement Report for Compliance Year 2013,* Docket E-999/PR-14-12; and *In the Matter of a Renewable Energy Certificate Retirement Report for Compliance Year 2012*, Docket E-999/PR-13-186.

5.2. The Planning Process

The following steps were followed in completing the resource planning process:

- Step 1: Determine Capacity and Energy Requirements
- Step 2: Identify Resource Options
- Step 3: Identification of Risk Factors to Analyze
- Step 4: Evaluate a Range of Expansion Plans

The procedures and assumptions used for each step are described below. The results of the planning process are described in section 6.

5.3. Step 1: Determine Capacity and Energy Requirements

The first step in the planning process is to ensure that adequate resources are available to meet all needs, including additional resources to meet reserve capacity requirements for reliability purposes. This step is necessary to meet the first goal of the planning process, namely to maintain the adequacy and reliability of power supply.

Section 4 described the load forecast and the current MRES resources. That analysis determined the extent to which MRES has a surplus or deficit of capacity during the planning period, and those results are summarized in the next table. The large changes in the early years are due to capacity sales and purchases, as well as the addition of the Red Rock Hydro Project.

Table 5-3 Capacity Surplus/Deficit in SPP and MISO by Year (MW)		
Year	**SPP Surplus**	**MISO (Deficit)**
2017	211	(59)
2018	55	(58)
2019	89	(69)
2020	90	(66)
2021	87	(64)
2022	86	(161)
2023	87	(158)
2024	237	(156)
2025	235	(154)
2026	236	(152)
2027	236	(150)
2028	232	(148)
2029	230	(146)
2030	227	(160)
2031	222	(159)

The capacity amounts include planning reserve requirements for the loads in both the SPP and MISO market areas. MISO requires utilities to meet the planning reserve margin by designating Planning Reserve Credits, which may be obtained from resources owned by other market participants. Under the Base Case assumptions, and in all of the sensitivity cases, MRES has surplus capacity in SPP and is deficit of capacity in MISO, as detailed in Section 4.5, above.

5.4. Step 2: Identify Resource Options

An appropriate slate of candidate resources is necessary in order to meet the second and third goals of the resource plan: keeping Members' wholesale rates competitive, and minimizing adverse socioeconomic and environmental effects. There are many generic types of resource options available to utilities when considering the need for additional capacity and/or energy. MRES first considered all potentially available resource options, and then refined that list of options to identify those realistically available for consideration for this plan.

5.4.1. Discussion of Potential Resource Options

- Thermal generation: Thermal resources include various technology types, sizes, and fuel sources. Examples include the intermediate and peaking resources specifically modeled in this resource plan. In addition, new coal units and nuclear units were considered early in the study, but were not included in the modeling due to their high cost and the lack of actual new projects being proposed at this time. The modeling details for the remaining thermal resource types are specified later in this section.

- Renewable Generation: Wind and solar generation is included in the modeling resources to represent renewable generation, including other potential technologies such as hydroelectricity. No specific new projects were identified for this study.

- Cogeneration/Combined Heat and Power: The current cogeneration activity was discussed in Section 4.1.2. Based on that, no additional cogeneration or CHP units were assumed for this resource plan.

- New transmission facilities of various types and sizes: MRES participates in regional transmission expansion and improvement groups in both the SPP and MISO regions, such as the MISO Regional Expansion Criteria and Benefits (RECB) group. In the past, MRES has also partnered with other utilities to develop regional transmission resources when appropriate, such as the CapX 2020 initiative. MRES is a CapX participant and owner of the recently energized Fargo and Brookings County Projects. Currently there are no transmission facility opportunities that would affect the resource planning results.

- Upgrades or life extensions of existing generation and transmission equipment: No additional upgrades or life extensions to existing generators or transmission facilities have been identified as economical at this time. All existing resources are expected to be available to MRES through at least the end of the study period.

- Load-control equipment and utility-sponsored conservation programs: As described earlier, MRES is active in assisting Members with these activities. A large amount of load reduction is already assumed in this resource plan due to DSM and conservation activities. Forecasted amounts of expected conservation and DSM are explicitly included in the capacity expansion modeling.

- Purchases from other utilities and non-utilities: Resource options in the modeling also include market purchases and bilateral contracts. These purchases are considered in the models in several ways.

    Energy purchases from the MISO and SPP markets are included in the resource modeling. The markets are well established for energy transactions and include many utility and non-utility participants. The respective energy market parameters of MISO and SPP are built into all capacity expansion sensitivity cases run for this resource plan.

Also, as discussed previously, MRES expects to purchase capacity to cover its shortfall of capacity requirements in MISO, either directly from other MISO participants (utilities and non-utilities) through bilateral contracts or indirectly through the MISO auction.

- Base-Load Capacity: There are no current economic opportunities in the MISO region to purchase long-term base-load capacity, or to join with others to build a large base-load resource. While it is possible to obtain additional capacity from existing coal units, such purchases also come with the associated risks related to future carbon or other emission regulations. Therefore no base-load capacity option is included in the modeling for this resource plan. Given the anticipated low load growth and the high amount of LRS and Point Beach base-load capacity currently in the MRES portfolio, it is unlikely that MRES will have a need for any baseload capacity additions during the planning period.

5.4.2. Refinement of Resource Options Available for the Plan

The following particular resource options were considered in this resource plan. Because no specific site or resource is currently contemplated by MRES, all options are intended to be a generic representation of their type of resource, and the typical size represents the incremental resource addition required when such a resource is selected.

Intermediate: NGCC. The NGCC unit modeled was based on these characteristics:

- Typical Size: 108.7 MW, available beginning 2022
- Fuel: Natural Gas
- Heat Rate: **[TRADE SECRET DATA HAS BEEN EXCISED]** Btu/kWh
- Plant Availability: **[TRADE SECRET DATA HAS BEEN EXCISED]** %
- Emissions:
  - SO_2: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - PM_{10}: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - CO: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - NO_x: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - Pb: **[TRADE SECRET DATA HAS BEEN EXCISED]**
  - CO_2: [**TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
- Ancillary Service Costs: None; NGCC will be a net supplier of ancillary services.
- Source: Burns & McDonnell 2x1 LM 6000 CCGT Feasibility Study, dated July 2013.

Peaking: Duct-Fired Turbine addition on a NGCC facility was modeled with these characteristics:

- Typical Size: 49.2 MW, available beginning 2022
- Fuel: Natural Gas
- Heat Rate: **[TRADE SECRET DATA HAS BEEN EXCISED]** Btu/kWh:
- Plant Availability: **[TRADE SECRET DATA HAS BEEN EXCISED]** Btu/kWh
- Emissions:
  - SO_2: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - PM_{10}: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - CO: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - NO_x: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - Pb: **[TRADE SECRET DATA HAS BEEN EXCISED]**
  - CO_2: **[TRADE SECRET DATA HAS BEEN EXCISED** lbs/MMBtu
- Ancillary Service Costs: None; Duct-Fired Turbine will be net supplier of ancillary services.
- Other features: Duct-firing is only available as an addition to a specifically designed NGCC facility (*e.g.*, the facility listed above). It creates added output when needed for system reliability, or during hours when market prices are high. The efficiency of the duct-fired component is relatively low; the lower capital costs may, nonetheless, make it an economical and environmentally-sensitive way to add peaking capacity.
- Source: Burns & McDonnell 2x1 LM 6000 CCGT Feasibility Study, dated July 2013.

Peaking-CT: Simple-Cycle CT. A CT unit was modeled on these characteristics:

- Typical Size: 83.8 MW, available beginning 2022
- Fuel: Natural gas and fuel oil (dual fuel)
- Heat Rate: **[TRADE SECRET DATA HAS BEEN EXCISED]** Btu/kWh
- Plant Availability: **TRADE SECRET DATA HAS BEEN EXCISED** %
- Emissions:
  - SO_2: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - PM_{10}: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - CO: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - NO_x: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
  - Pb: **[TRADE SECRET DATA HAS BEEN EXCISED]**
  - CO_2: **[TRADE SECRET DATA HAS BEEN EXCISED]** lbs/MMBtu
- Ancillary Service Costs: None; a CT will be a net supplier of ancillary services.
- Other features: The CT is a proven technology, with which MRES staff is familiar. It has a relatively low initial cost and short construction cycle, making it attractive for peaking and reserve generation applications. In addition, one or two CT units can become the initial phases of a combined cycle plant.
- Source: Burns & McDonnell 2XLM6000 Simple Cycle Feasibility Study, dated September 2014.

Renewable-WIND: Wind Turbines. Wind was modeled based on these characteristics:

- Typical Size: 2 MW, modeled in 10 MW or 50 MW wind farm groupings, depending on sensitivity case, available beginning 2018
- Fuel: Wind
- Plant factor: 33%
- Emissions: None
- Ancillary service cost: 6.3 mills per kWh in 2015, inflated at 3% annually.
- Other features: Wind turbines located at or near Member cities can increase the local visibility of projects, create public awareness of, and support for, renewable energy.
- Other: Because wind is an intermittent resource, its primary value is for energy. Given the intermittency. The accredited value of a wind turbine cannot be determined from its name-plate value. For study purposes, MRES estimated a 15% wind accreditation based on historic practices and experience in MISO. (Only MISO standards were considered because MRES has surplus resources in SPP and is deficit in MISO. For that reason, new wind resources would be primarily located in MISO.)
- Source: Historic practices and experience based on development and ownership of wind generation, as well existing wind contracts and market conditions.

Renewable-Solar: Photo-Voltaic Solar: Solar was modeled using these characteristics:

- Typical Size: 1 MW, available beginning 2019.
- Fuel: Sun
- Plant factor: 21.49%
- Emissions: None
- Ancillary Service Costs: None were assumed.
- Other features: Studies of several locations and fixed versus tracking solar panels revealed that fixed panels located in the southern portion of the Members' service territory were the most favorable configuration, with the resulting costs and generation profiles included in this IRP. Solar panels located at or near Member cities can increase the local visibility of the project and be an important tool to create public awareness of, and support for, renewable energy.
- Other: For study purposes, MRES did not assume any accreditation.
- Source: Westwood MRES Solar Feasibility Study, dated January 2015.

5.5. Step 3: Identification of Risk Factors to Analyze

Study goal 4 is to enhance the ability of MRES to respond to changes and limit its risks. Utility operations are subject to a variety of risks, and there are many ways to classify those risks. For instance, risks may vary from internal to external risks, short-term to long-term risks, controllable to uncontrollable risks, and quantifiable to qualitative risks.

For this resource plan, MRES identified for analysis risks based on a review of prior resource plans, regulatory requirements, and management judgment of the utility environment. The risks selected for evaluation were those that are relatively uncontrollable, subject to quantitative analysis, and significant to resource planning results.

5.5.1. Operations in Two RTO Markets

On October 1, 2015, WAPA transferred functional control of its transmission system into the SPP market area, including facilities that serve MRES Member load. As a result, MRES was, as a practical matter, required to join the SPP market, and transfer control of its transmission assets in the region to SPP as well. As of October 1, 2015, all MRES loads and resources are located within either the MISO or the SPP markets. SPP has a 13.64% planning reserve requirement for its members. This IRP assumes the 13.64% requirement for all MRES load in SPP, plus the MISO resource adequacy requirements for load in MISO (as discussed more specifically in Subsections 4.2 and 4.3).

With the division of MRES loads and resources into two RTO markets for the first time, MRES encounters a number of risks related to power supply and transmission. When WAPA joined SPP and transferred functional control of its facilities to SPP in October 2015, many utilities in the region were obligated (as a practical matter) to also join SPP and transfer transmission facility control to SPP. As a result, each of those utilities has been required to establish new tariffs for service in SPP (including tariffs relating to MRES and select MRES SPP Members), which has resulted in uncertainty regarding the treatment of certain long-term, pre-existing transmission service arrangements (referred to as grandfathered agreements). While MRES went through a similar period of uncertainty when MISO was created in 1998, and began operation of real-time and day-ahead markets in 2005, SPP's organizational roots date back to 1941, and its structure and procedures are different from those in MISO.

FERC is in the process of reviewing these new tariffs, as well as corresponding changes to the SPP tariff itself, and the joint operating agreement between SPP and MISO. It is not possible at this time to predict the outcome of these regulatory proceedings and, because they will be instrumental in determining transmission-related costs in SPP, they create uncertainty regarding transmission costs generally, and indirectly also are expected to affect the price of resources in the SPP market (including LRS).

Only resources within the same RTO, or that have appropriate firm transmission in place from another RTO, may be used to meet the capacity requirements in an RTO. MRES and its Members exist in two separate RTO regions, and there are very limited transmission rights between those regions. Thus, for the first time MRES has split the capacity expansion modeling into two separate models, one for the SPP region and one for the MISO region. This allows for modeling based on the specific characteristics of each RTO.

5.5.2. Future CO_2 Emission Costs

A significant source of uncertainty in the electric industry is the regulation of CO_2; while it is widely accepted that regulation is inevitable, the form of that regulation remains uncertain. In the absence of a legislative framework, EPA finalized its executive branch rulemaking to reduce CO_2 emissions in August 2015. That entire EPA regulatory construct has been stayed by an order of the United States Supreme Court, pending the completion of legal challenges to the rule. Those challenges are expected to take a number of years before a final judgment is reached, leaving the utility industry with continued regulatory uncertainty on this important issue.

In an effort to address the uncertainty caused by the failure of Congress to enact federal laws to regulate CO_2, Minnesota's Legislature directed the Commission to address this federal policy gap.[23] In December 2007, the Commission instituted the requirement that utilities include in their resource planning an estimate of the future cost of CO_2 emissions, and set that value between $4 and $30 per ton.[24] In the Commission's most recent Order on this matter, the range of the likely cost of CO_2 regulation was set at $9 to $34 per ton, and utilities were directed to begin applying this range for planning years beginning in 2019 and beyond.[25]

Based on that order, MRES selected a mid-range price of $21.50 (2015 dollars) for the future cost of CO_2 regulation in its Base Case model. The values included in the sensitivity cases are $0 and $34 per ton in 2015 dollars. MRES selected the low range as

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[23] *See* Minn. Stat. § 216H.06.

[24] *See* "Order Establishing Estimate of Future Carbon Dioxide Regulation Costs," *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06*, Minnesota Public Utilities Commission, Docket No. E-999/CI-07-1199, December 21, 2007, at 11.

[25] "Order Establishing 2014 and 2015 Estimate of Future Carbon Dioxide Regulation Costs," *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06*, Minnesota Public Utilities Commission, Docket No. E-999/CI-07-1199, April 28, 2014, at 4.

\$0 per ton based on the fact that, at the present time, the price for CO_2 emissions is \$0 per ton and that value provides the absolute bottom end of the possible range.[26]

It is important to have a consistent set of forecast assumptions for CO_2 emissions costs, as those assumptions also affect the forecasts for natural gas prices and electricity market prices. MRES commissioned Energy Ventures Analysis, Inc. (EVA)[27] to analyze electricity market and natural gas prices, and to create a consistent set of forecasts for those prices through 2040, based on various assumptions regarding future costs for CO_2 emissions. The EVA study was completed in April 2015 and is summarized in Tables 5-4 through 5-7, with further details in Appendix I. In commissioning this study, MRES asked EVA to create sets of electricity and natural gas price forecasts using these assumptions regarding future CO_2 emission costs:

- Base case: \$21.50 in 2015 dollars (\$24.92 in nominal dollars by 2020) per ton of CO_2 beginning in 2020, escalating with inflation through the end of the study.
- High Carbon sensitivity case: \$34.00 in 2015 dollars (\$39.42 in nominal dollars by 2020) per ton of CO_2 beginning in 2020, escalating with inflation through the end of the study.
- Zero Carbon sensitivity case: No CO_2 cost assumed.

Most sensitivity cases in this plan assume the \$21.50 CO_2 cost sensitivity, meaning CO_2 emissions from all existing and new MRES resources were priced at \$24.92/ton starting in 2020, along with the corresponding EVA natural gas and electricity market price forecasts, as shown in Table 5-4. As this table shows, the cost of electricity makes a notable increase in 2020 when the CO_2 cost is first included. This also occurs for the natural gas prices.

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[26] While MRES is aware that the Commission-established low value is \$9 per ton, as a matter of acquiring data to conduct its sensitivity analyses, MRES considered the cost to acquire the additional data for corresponding inputs, the amount of time required to process the additional modeling, the practices of Commission rate-regulated utilities in submitting similar resource plans, and consulted with staff of the Department of Commerce, Division of Energy Resources. Further, because the low-CO_2 value is and input to only a sensitivity case and is not a basic input for the Base case or a significant number of alternatives, the impact of using a \$0 value was expected to be minimal. Based on these factors, MRES opted to use the value of \$0 per ton as the low range of the sensitivity analysis.

[27] Note that the EVA data provided to MRES begins with 2020 instead of 2019. In discussions with the consultant regarding the starting date for the data, EVA explained that using 2020 as the beginning of the data set is based on the fact that, at the time the study was commissioned, the majority of the industry was using the 2020 date for the first year of analysis because it was widely anticipated at that time that proposed regulation of CO_2 emissions would begin in 2020.

Table 5-4 "BASE CASE" Market Price Assumptions			
Year	Base Case		
	$21.50 CO_2 $/Ton	Natural Gas $/MMBtu	Electricity $/MWh
2017	$ 0.00	TRADE SECRET DATA HAS BEEN EXCISED	
2018	$ 0.00		
2019	$ 0.00		
2020	$24.92		
2021	$25.67		
2022	$26.44		
2023	$27.24		
2024	$28.05		
2025	$28.89		
2026	$29.76		
2027	$30.65		
2028	$31.57		
2029	$32.52		
2030	$33.50		
2031	$34.50		

Sensitivity cases were run using the zero and high CO_2 emissions price assumptions, as shown in Tables 5-5 and 5-6. Again, the different CO_2 emissions costs affect the other prices starting in 2020.

Table 5-5 "ZERO CO_2 CASE" Market Price Assumptions			
	Zero Carbon		
Year	$0 CO_2 $/Ton	Natural Gas $/MMBtu	Electricity $/MWh
2017	$0.00	TRADE SECRET DATA HAS BEEN EXCISED	
2018	$0.00		
2019	$0.00		
2020	$0.00		
2021	$0.00		
2022	$0.00		
2023	$0.00		
2024	$0.00		
2025	$0.00		
2026	$0.00		
2027	$0.00		
2028	$0.00		
2029	$0.00		
2030	$0.00		
2031	$0.00		

Table 5-6 "HIGH CO_2 CASE" Market Price Assumptions			
	High Carbon		
Year	$34.00 CO_2 $/Ton	Natural Gas $/MMBtu	Electricity $/MWh
2017	$ 0.00	TRADE SECRET DATA HAS BEEN EXCISED	
2018	$ 0.00		
2019	$ 0.00		
2020	$39.42		
2021	$40.60		
2022	$41.82		
2023	$43.07		
2024	$44.36		
2025	$45.69		
2026	$47.06		
2027	$48.48		
2028	$49.93		
2029	$51.43		
2030	$52.97		
2031	$54.56		

5.5.3. Uncertainty of Natural Gas and Electricity Market Price Forecasts

Although the CO_2 emissions sensitivity cases produce results that vary the price forecasts for natural gas and electricity markets, those cases only examine the variation caused by changing CO_2 emissions costs. An additional sensitivity case was run to examine an increase in commodity price. The natural gas and electricity prices were grouped together for this analysis (see Table 5-7).

- The market prices used in the Base Case assume that, in 2017, the natural gas price is **[TRADE SECRET DATA HAS BEEN EXCISED]** /MMBtu and the electricity market price is **[TRADE SECRET DATA HAS BEEN EXCISED]** /MWh. By 2031, those prices increase to **[TRADE SECRET DATA HAS BEEN EXCISED]** /MMBtu and **[TRADE SECRET DATA HAS BEEN EXCISED]** /MWh, respectively.
- The high market price sensitivity case assumed notably higher prices. By 2031, the natural gas price is escalated to **[TRADE SECRET DATA HAS BEEN EXCISED]** /MMBtu and the electricity market price is **[TRADE SECRET DATA HAS BEEN EXCISED]** /MWh.

- Each of these Market Price assumption sensitivity cases assumed the same CO_2 emission costs as were defined for the $21.50 CO_2 Base Case.

- To evaluate the Market Price sensitivities for natural gas and electricity commodities in the case of the alternate CO_2 cases (zero carbon and $34.00/high cost), the natural gas and electricity market prices adjust in response to the CO_2 price changes via a feedback loop in the pricing model.

The natural gas and market prices resulting from these cases are shown below in Table 5-7. The natural gas and electricity market prices shown in Table 5-7 come from the cases with $21.50 (base) CO_2 prices.

Table 5-7
"HIGH GAS/MARKET" Market Price Assumptions

Year	$21.50 CO_2 $/Ton	High Prices Natural Gas $/MMBtu	High Prices Electricity $/MWh
2017	$ 0.00	TRADE SECRET DATA HAS BEEN EXCISED	
2018	$ 0.00		
2019	$ 0.00		
2020	$24.92		
2021	$25.67		
2022	$26.44		
2023	$27.24		
2024	$28.05		
2025	$28.89		
2026	$29.76		
2027	$30.65		
2028	$31.57		
2029	$32.52		
2030	$33.50		
2031	$34.50		

5.5.4. Impact of CAA Regulations

In terms of potential risks, uncertainty presented by existing and potential regulations pursuant to the Clean Air Act, are external variables over which MRES has limited control, and which may involve significant changes to power supply options and the cost to provide power supply to MRES Members. In Subsections 1.2.1 through 1.2.4 above, MRES identified Regional Haze, CO_2 emission limits, and a variety of other regulations that may potentially impact primarily LRS as the only MRES coal-fired resource. For this reason, MRES developed a sensitivity case in the SPP models to simulate the potential impact of shutting down one of the three coal units comprising LRS. Shut down of one unit was used as a proxy for the impact of environmental regulations under the CAA, such as the Regional Haze regulations imposed by the Wyoming FIP that is currently on appeal. In this sensitivity case, LRS is reduced from 282 MW to 188 MW starting in 2022. This reduction reflects the continued 16.47% ownership share of LRS.

5.5.5. Load Forecast Uncertainty

The load forecast is a significant driving variable for the resource plan. Any long-term under- or over-forecast of load will mean a significant change in resource plan results. It is for this reason that the load forecasts include not only an expected, Base Case, but also low and high forecasts to assess the sensitivities of the load forecasts.

- The low load forecast sensitivity case assumes the load forecasts will increase at a rate that is 0.5% per year less than the growth rate used in the Base Case. By 2031, this reduces MRES loads by 30.4 MW and 171.7 GWh in MISO, and by 38.2 MW and 180.9 GWh in SPP.

- The high load forecast sensitivity case assumes the load forecasts will increase at a rate that is 0.5% per year more than the growth rate used in the Base Case. By 2031, this increases MRES loads by 32.5 MW and 183.6 GWh in MISO, and by 41.0 MW and 289.1 GWh in SPP.

5.5.6. Uncertainty of Ability to Achieve the Full 1.5% CIP Reduction Each Year for Minnesota Loads

Section 3 above described the latest DSM Potential Study and the assumptions used to estimate the amounts of DSM reductions for this resource plan. The ability to achieve the full CIP in Minnesota Member communities is influenced by many external factors that present considerable uncertainty that depends on consumer behavior or other variables.

- For its Base Case (and all but one sensitivity case), MRES assumed its Members will achieve the full 1.5% per year CIP reduction in Minnesota, along with the full Market Potential amount in the other three states. This results in a total MRES Member coincident load reduction of 175.2 MW and 688.4 GWh by 2031 (see Table 3-7).

- MRES also conducted an alternative sensitivity case – the “Expected Conservation” case – that models only the amounts of DSM that are feasible under the Market Potential calculations in the Morgan/Cadmus DSM Study, as calculated at the time of the MRES peak. Those amounts appear in the rightmost columns of Table 3-6.

5.5.7. 50% and 75% of Future Resources Supplied by Conservation and Renewable Resources

The Commission also requires utilities to include in their planning analysis the least cost plan for meeting 50% and 75% of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.[28]

[28] Minn. Stat. § 216B.2422, subd. 2. This planning requirement also assists MRES in evaluating its role in the progress toward achieving the reduction of “statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.” Minn. Stat. § 216H.02, subd. 1.

In the SPP Base Case, the results of the Strategist modeling demonstrates that at least 75% of all future resource additions are renewable resources and conservation, and therefore no additional 50% or 75% cases were required for the SPP models.

The results of the Base Case analysis for MISO, however, did not achieve these levels of renewables. Accordingly, two MISO sensitivity cases were included that force the addition of 50% and 75% renewable resources and conservation. Because MISO accredits wind capacity at approximately 15% of its nameplate value, it requires several hundred MW of wind capacity to supply 50% to 75% of future resource needs, as these sensitivity cases show.

5.6. Step 4: Evaluate a Range of Expansion Plans

The capacity expansion plans were calculated under the sensitivity cases using the various assumptions as described above in order to meet the study goals for this resource plan. Table 5-8 summarizes the set of cases analyzed using the capacity expansion analysis.

Table 5-8 Scenarios Analyzed	
1.	SPP Base Case
2.	SPP Zero CO_2 Emission Cost Sensitivity
3.	SPP High CO_2 Emission Cost Sensitivity
4.	SPP High Gas & Market Prices Sensitivity
5.	SPP Low Load Forecast Sensitivity
6.	SPP High Load Forecast Sensitivity
7.	SPP LRS Reduction Sensitivity
8.	SPP Expected Conservation Sensitivity
9.	MISO Base Case
10.	MISO Zero CO_2 Emission Cost Sensitivity
11.	MISO High CO_2 Emission Cost Sensitivity
12.	MISO High Gas & Market Prices Sensitivity
13.	MISO Low Load Forecast Sensitivity
14.	MISO High Load Forecast Sensitivity
15.	MISO 50% Renewable Sensitivity
16.	MISO 75% Renewable Sensitivity
17.	MISO Expected Conservation Sensitivity

5.7. Modeling Software

MRES utilized the Strategist® capacity expansion software tool in the development of this resource plan. This modeling tool allows base load, peaking, and other resources to compete with renewable energy resources, conservation, and DSM in developing the resource plan that minimizes costs. Once the optimal resource mix was identified under the Base Case set of assumptions, Strategist was used to model several sensitivity cases that were then used to analyze the financial risks associated with uncontrollable events.

5.8. Modeling Assumptions

In presenting the planning results, all costs shown include the production costs for existing and future resources, plus capital costs for all new resources. (The results do not include capital costs for existing resources.) Emissions costs and market energy purchase costs were also included. Revenues from market sales in excess of firm Member loads were not considered in determining the optimal resource mix.

A capacity expansion analysis was also performed for each of the sensitivity cases. This analysis evaluated the effects of each set of variables in detail over the 2017-2031 study horizon, plus it estimated the benefits and costs of each resulting resource mix for the end effects period into perpetuity.

The Strategist model was used to optimize the future resource mix while requiring that planning reserves and RES requirements are met. The models were first run without allowing any market sales, *i.e.* with generation output limited each hour to no more than the hourly load. Once the optimum resource plan was determined under those conditions, a final run was then completed with the optimal resource plan locked in and market sales enabled, to calculate the overall expected cost of the expansion plan to minimize costs. In this manner, the final costs include the expected impact of operating the selected resource plan in the RTO markets.

The following additional assumptions were used in the Base Case analysis:

- 3% inflation applied to all costs unless otherwise identified
- 6% discount rate applied to all results when calculating present-worth values
- Adequate wind resources were included in every year to meet the Minnesota RES (up to 25% by 2025), and to achieve a 10% renewable goal for the other three states
- New wind resources are assumed to have a 15% nameplate capacity accreditation value
- 4% LRS transmission losses (reflects the typical discount on average market prices)
- 2014 Base Year in Strategist models
- $21.50 per ton CO_2 cost beginning 2020
- In MISO, the capacity deficit is calculated after assuming credit for capacity purchases, and credit for the portion of capacity supplied from WAPA resources as described in Subsection 4.3.6, above.

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Part VI: Capacity Expansion Plan Results

6. Expansion Plan Results

In this section, the results of the capacity expansion modeling for both the SPP and the MISO portions of the MRES power supply requirements are presented and summarized. A comparison is provided showing the relative impacts of the alternative scenarios on the total costs as compared to the Base Case, and conclusions are presented. Finally, the plan details the basis of the conclusion that the results are in the public interest, and action plans are outlined for both the short term and the long term.

6.1. Expansion Plan Analysis Results – SPP Region

Using the Modeling Assumptions described in Subsection 5.8 above, MRES used Strategist to perform capacity expansion modeling for the Base Case, as well as each sensitivity case. The results were analyzed and provide results that identify the costs for each case given the expected impact of operating the selected resource plan in the SPP market. The final cost, with market sales allowed, is reported in 2014 dollars in the subsections that follow.

The graphs below show the net capacity additions that accrue toward planning reserve requirements.[29]

6.1.1. SPP Base Case Results

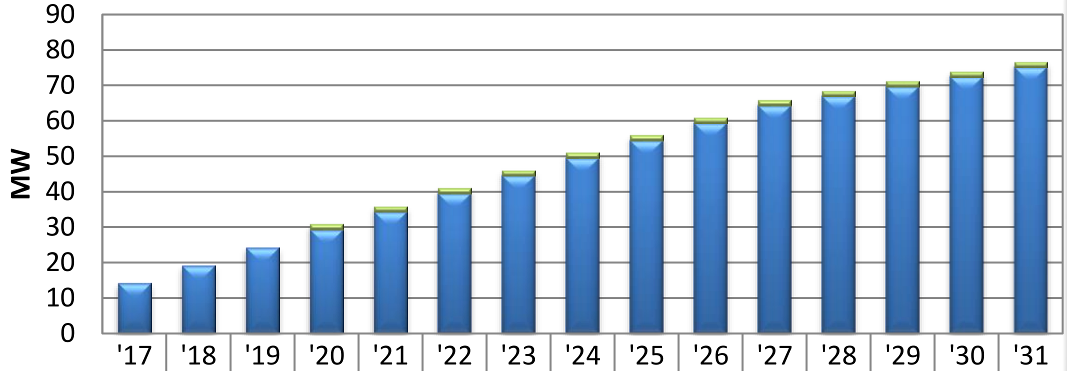
In addition to the general modeling assumptions identified in Subsection 5.8, the SPP Base Case also includes the following assumptions:

- CIP Reductions: **Full CIP**
- CO_2 Emission Costs: **$21.50**
- Market & Natural Gas Prices: **Base values**
- Load Forecasts: **Base values**
- Other Assumptions: **None**

Based on these inputs, the results of SPP Base Case are summarized in the following graph:

[29] In the case of wind capacity, note that the amount of nameplate capacity required to achieve the net capacity requirements is substantially higher given that RTO accreditation standards require the installation of approximately 10 MW of nameplate capacity to obtain accreditation of 1.5 MW capacity for wind resources.

Graph 6-1: SPP Base Case
$2,632.2 million – Cost in 2014 Dollars



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind				1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
DSM/CIP	14.3	19.2	24.3	29.4	34.4	39.5	44.5	49.5	54.5	59.4	64.3	67.0	69.7	72.4	75.1

The SPP Base Case results in the addition of 76.6 MW of capacity through 2031. All of that capacity - 100% - is from non-fossil fuel resources. In 2031, the SPP Base Case requires the addition of 75.1 MW of DSM/conservation and 1.5 MW of renewable capacity (modeled here as wind). No additional sensitivity cases are required to study 50% and 75% renewable additions. (As noted above, this case would assume the installation or acquisition of wind resources with a nameplate total of approximately 10 MW.)

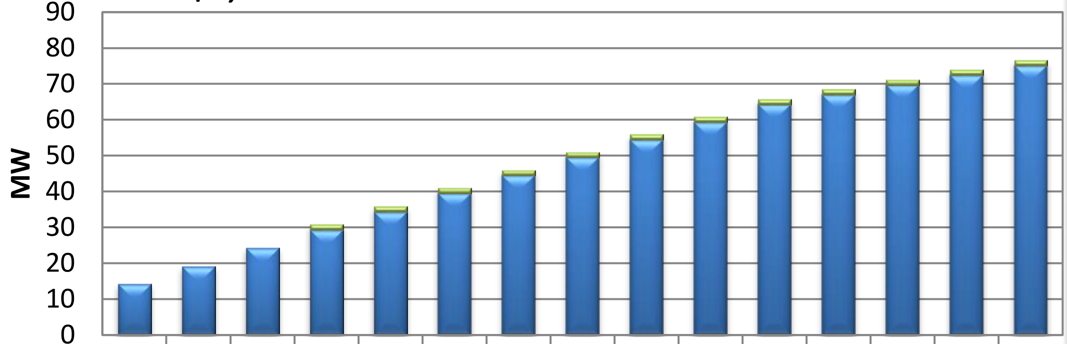
6.1.2. SPP CO_2 Emission Cost Sensitivity Cases

These sensitivity cases evaluate both the impact of the low and high CO_2 costs for emissions, as well as the corresponding impact on the price calculations for market and natural gas purchases.

SPP Zero CO_2 Emission Cost Sensitivity. This sensitivity case relies on the following assumptions, as compared to the Base Case:

- CO_2 Emission Costs: **$0.00**
- Market & Natural Gas Prices: **Adjusted for $0 CO_2 Costs**

Graph 6-2: SPP Zero CO_2 Emission Cost Sensitivity Case
\$1,358.4 million – Cost in 2014 Dollars

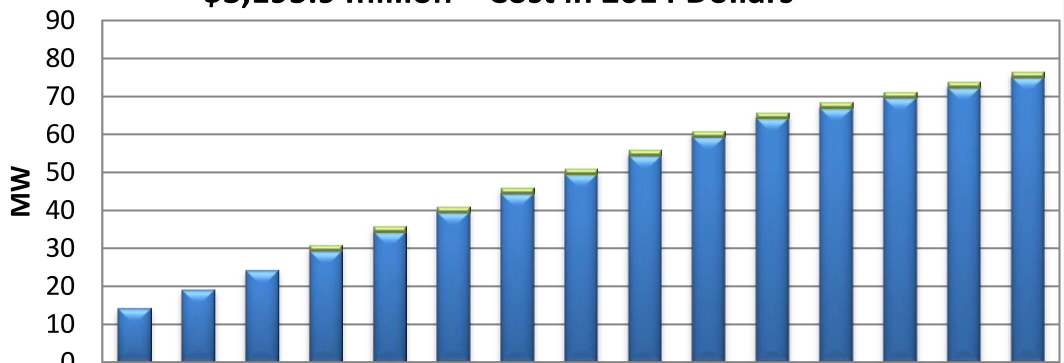


	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind				1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
DSM/CIP	14.3	19.2	24.3	29.4	34.4	39.5	44.5	49.5	54.5	59.4	64.3	67	69.7	72.4	75.1

SPP High CO_2 Emission Cost Sensitivity. This sensitivity case relies on the following revisions to the assumptions used in the Base Case:

- CO_2 Emission Costs: **\$34.00**
- Market & Natural Gas Prices: **Adjusted for \$34 CO_2 Costs**

Graph 6-3: SPP High CO_2 Emission Cost Sensitivity Case
\$3,195.9 million – Cost in 2014 Dollars



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind				1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
DSM/CIP	14.3	19.2	24.3	29.4	34.4	39.5	44.5	49.5	54.5	59.4	64.3	67	69.7	72.4	75.1

As Graphs 6-2 and 6-3 show, varying the cost of CO_2 emissions over the sensitivity range does not affect the needed resource additions in the SPP resource plan. This is largely because MRES already has surplus capacity in SPP for all years in the planning period, and because the capacity additions in the expansion plan are from resources that have no associated emissions. The cost of emissions does impact externalities costs and market prices, which impact the overall cost of the sensitivity cases, as described further below.

Most of the remaining SPP sensitivity cases have a similar result, namely that the sensitivity cases have little or no impact on the capacity portfolio, although they do have some impact on overall market price and other modeled costs.

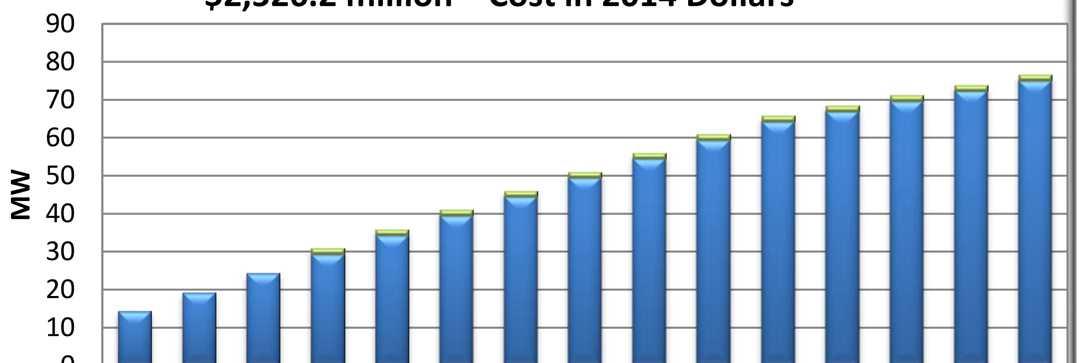
6.1.3. SPP Gas & Market Price Sensitivity Case

This sensitivity case evaluates the impact of both high natural gas and high electric market prices, using the Base Case value of \$21.50 CO_2 for emission costs.

SPP High Gas & Market Prices Sensitivity. This sensitivity case relies on the following assumptions, as compared to the Base Case:

- Market & Natural Gas Prices: **High Gas & Market Costs**

Graph 6-4: SPP High Gas & Market Prices Sensitivity Case
\$2,526.2 million – Cost in 2014 Dollars



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind				1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
DSM/CIP	14.3	19.2	24.3	29.4	34.4	39.5	44.5	49.5	54.5	59.4	64.3	67	69.7	72.4	75.1

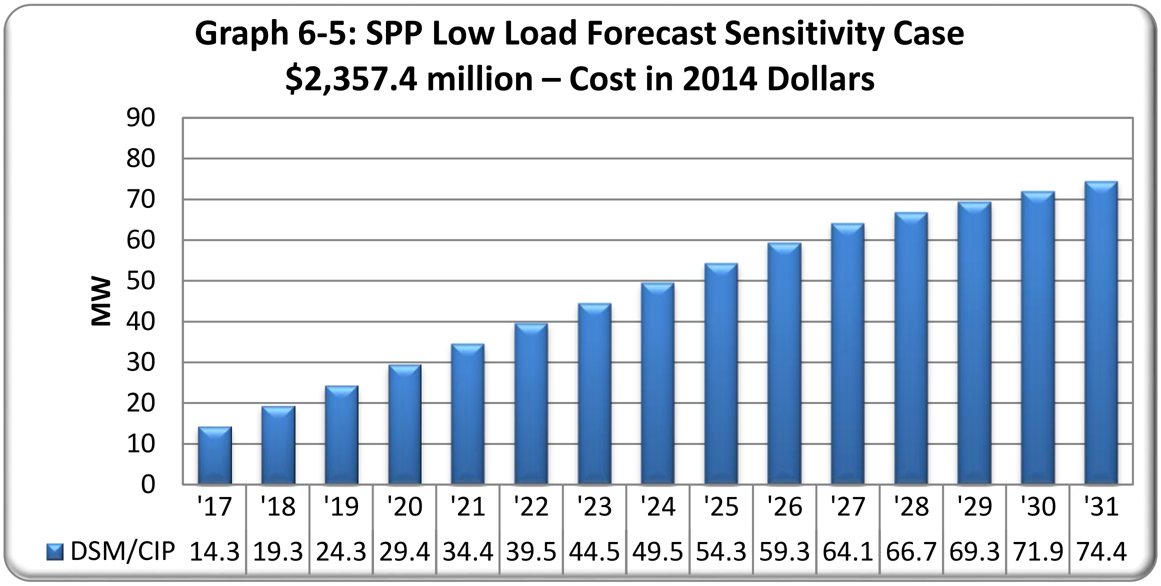
The Gas and Market Price sensitivity case for SPP demonstrates that higher commodity prices will not affect the resource additions and have little impact on the cost of the expansion plan.

6.1.4. SPP Load Forecast Uncertainty Sensitivity Cases

These sensitivity cases were modeled to evaluate the impact of both lower than expected load growth and higher than expected load growth.

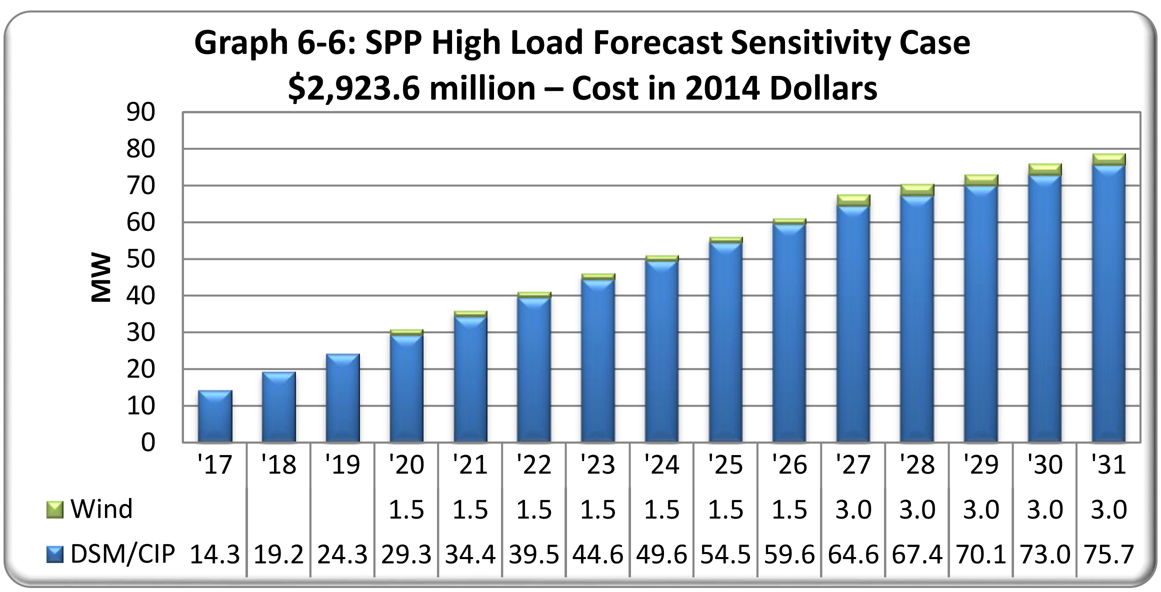
SPP Low Load Forecast Sensitivity. The low load sensitivity case differs from the Base Case assumption in one important way:

- Load Forecasts: **Low Load Forecast**



SPP High Load Forecast Sensitivity. Likewise, the high load sensitivity case differs from the Base Case assumption in one important way:

- Load Forecasts: **High Load Forecast**



The SPP Low and High Load Forecast Sensitivity cases demonstrate only minor effects as compared to the SPP Base Case. The Low Sensitivity eliminates the need for renewable (wind) resource additions, and the High Sensitivity results in similar resource additions, with an increase in renewable resources of 1.5 MW from 2027 through 2031, and a slight cost increase of $291 million compared to the SPP Base Case.

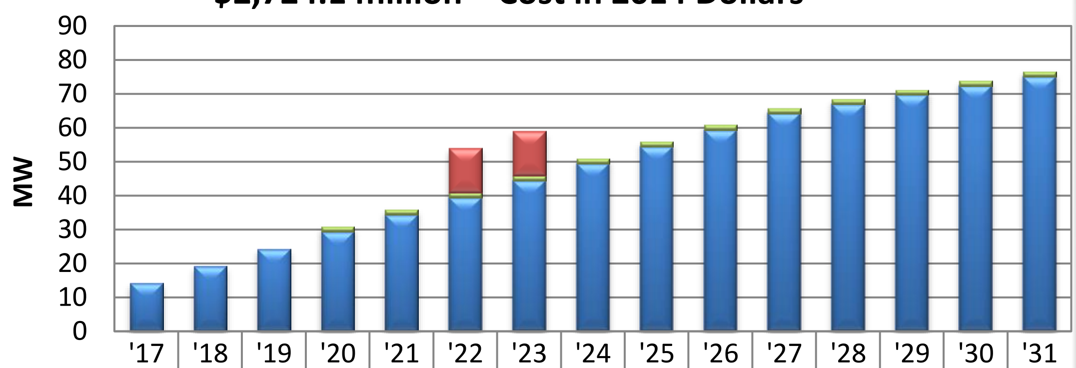
6.1.5. SPP LRS Reduction Sensitivity Case

This sensitivity case evaluates the impact of reducing LRS from 282 MW to 188 MW starting in 2022. This is to simulate the potential impact of shutting down one of the three coal units comprising LRS, due to environmental regulations under the CAA, such as regional haze rules.

SPP LRS Reduction Sensitivity. This alternative case involves a single change from the Base Case:

- Other Assumptions: **LRS Reduction Starting 2022**

Graph 6-7: SPP LRS Reduction Sensitivity Case
$2,724.1 million – Cost in 2014 Dollars



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Purchase						13	13								
Wind				1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
DSM/CIP	14.3	19.2	24.3	29.4	34.4	39.5	44.5	49.5	54.5	59.4	64.3	67	69.7	72.4	75.1

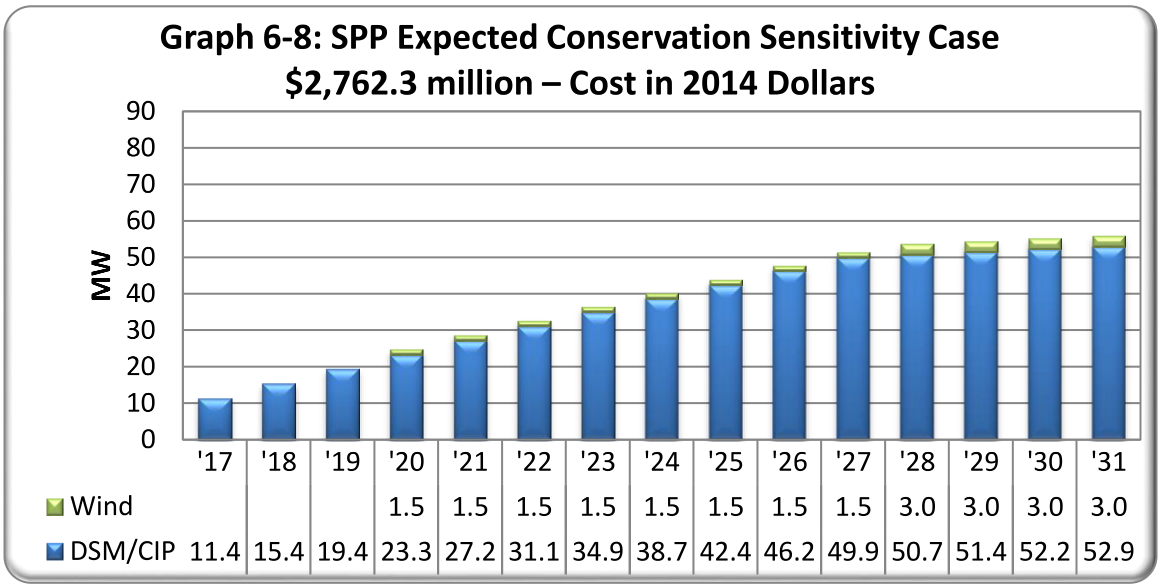
Notably, this alternative results in the addition of market purchases in 2022 and 2023. The "Purchase" amounts indicate one-year capacity purchases of 13 MW to satisfy short-term resource needs during the first two years of the capacity reduction.

6.1.6. SPP Expected Conservation Sensitivity Case

This sensitivity case evaluates the impact if the amounts of demand-side management and conservation that are realized during the planning period are limited to only those that are likely based on the Morgan/Cadmus DSM Study.

SPP Expected Conservation Sensitivity. This case modeled one assumption different from the Base Case:

- CIP Reductions: **Expected CIP**



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind				1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	3.0	3.0	3.0	3.0
DSM/CIP	11.4	15.4	19.4	23.3	27.2	31.1	34.9	38.7	42.4	46.2	49.9	50.7	51.4	52.2	52.9

In SPP, the results show that if MRES is able to only attain demand-side management and conservation at the expected or achievable levels, it would create a need for an additional 1.5 MW of renewable resources (assumed for these purposes to be wind) from 2028 through 2031, due to the slightly higher loads under this sensitivity case. This results in a slightly higher cost of just over $130 million. MRES would, however, continue to have surplus capacity in SPP.

6.2. Expansion Plan Analysis Results – MISO Region

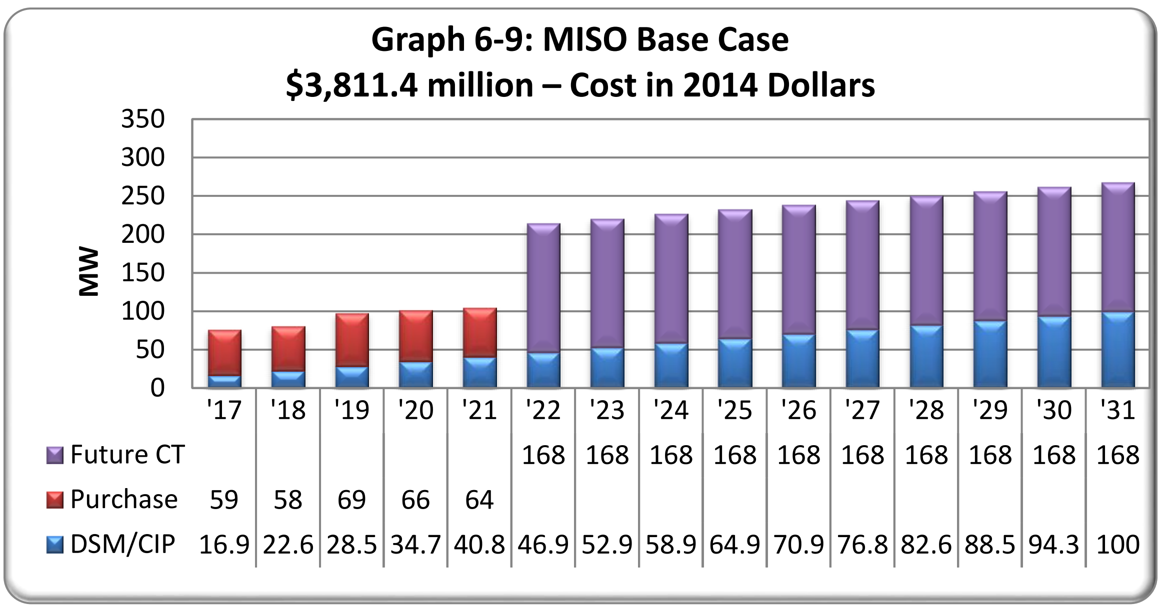
As in the SPP region, the capacity expansion plan was developed for each sensitivity case without allowing any market sales. Once the optimum resource plan was determined, a final run was completed with the optimal resource plan locked in and with market sales allowed. The final cost, with market sales allowed, is reported below in 2014 dollars.

Again, the graphs that follow illustrate the net capacity additions that accrue toward planning reserve requirements. The amount of nameplate capacity would often be higher in the event the renewable resource additions are wind generation, given the low accreditation of wind capacity in MISO. For instance 15 MW of wind capacity reported for meeting planning reserves would require approximately 100 MW of installed or purchased nameplate capacity.

6.2.1. MISO Base Case Results

Assumptions used for the MISO Base Case:

- CIP Reductions: **Full CIP**
- CO_2 Emission Costs: **$21.50**
- Market & Natural Gas Prices: **Base values**
- Load Forecasts: **Base values**
- Other Assumptions: **None**



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Future CT						168	168	168	168	168	168	168	168	168	168
Purchase	59	58	69	66	64										
DSM/CIP	16.9	22.6	28.5	34.7	40.8	46.9	52.9	58.9	64.9	70.9	76.8	82.6	88.5	94.3	100

The MISO Base Case results in the addition of 268 MW of capacity through 2031, which comes from a variety of supply and demand side resources. In the first five years of the MISO Base Case, the model indicates one-year capacity purchase amounts during the short term (first five years). Through the planning period to 2031, the expansion plan includes 100 MW of DSM/conservation and 168 MW of additional generation, modeled here as natural gas CTs.

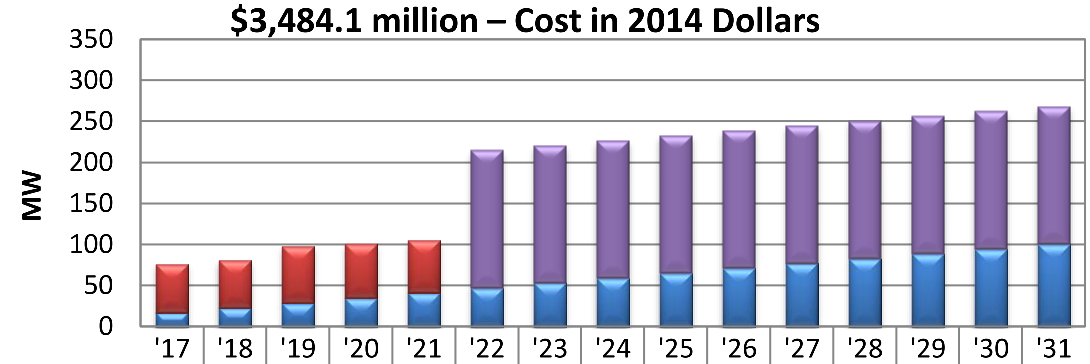
6.2.2. MISO CO_2 Emission Cost Sensitivity Cases

These sensitivity cases evaluate the impact of both low and high CO_2 costs, using $0 and $34 for emissions and in the price calculations for market and natural gas purchases.

MISO Zero CO_2 Emission Cost Sensitivity. This sensitivity case relies on the following assumptions, as compared to the Base Case:

- CO_2 Emission Costs: **$0.00**
- Market & Natural Gas Prices: **Adjusted for $0 CO_2 Costs**

Graph 6-10: MISO Zero CO_2 Emission Cost Sensitivity Case
$3,484.1 million – Cost in 2014 Dollars

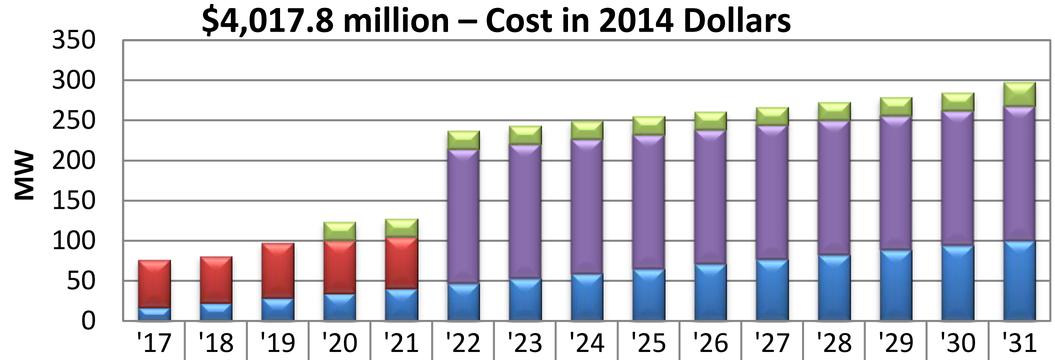


	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Future CT						168	168	168	168	168	168	168	168	168	168
Purchase	59	58	69	66	64										
DSM/CIP	16.9	22.6	28.5	34.7	40.8	46.9	52.9	58.9	64.9	70.9	76.8	82.6	88.5	94.3	100

MISO High CO_2 Emission Cost Sensitivity. This sensitivity case uses the following assumptions, as compared to the Base Case:

- CO_2 Emission Costs: **$34.00 CO_2 Costs**
- Market & Natural Gas Prices: **Adjusted for $34 CO_2 Costs**

Graph 6-11: MISO High CO_2 Emission Cost Sensitivity Case
$4,017.8 million – Cost in 2014 Dollars



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind				22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	30.0
Future CT						168	168	168	168	168	168	168	168	168	168
Purchase	59	58	69	66	64										
DSM/CIP	16.9	22.6	28.5	34.7	40.8	46.9	52.9	58.9	64.9	70.9	76.8	82.6	88.5	94.3	100

Varying the cost of CO_2 emissions over the sensitivity range does not significantly affect the type or size of resource additions in the MISO resource plan, as depicted in Graphs 6-10 and 6-11. The modeling results show minimal changes in the Low CO_2 and High CO_2 Sensitivity Cases from the Base Case. The most notable difference is that the High CO_2 sensitivity case requires the addition of 22.5 MW of renewable resources over most of the planning period, increasing to 30.0 MW of renewable resources (modeled here as wind) in 2031, with a corresponding increased cost of approximately $200 million. In MISO, the analysis demonstrates only some sensitivity to the price of CO_2. The cost of CO_2 emissions does, however, impact externalities costs and market prices, which in turn impact the overall cost of the sensitivity cases, and is discussed below.

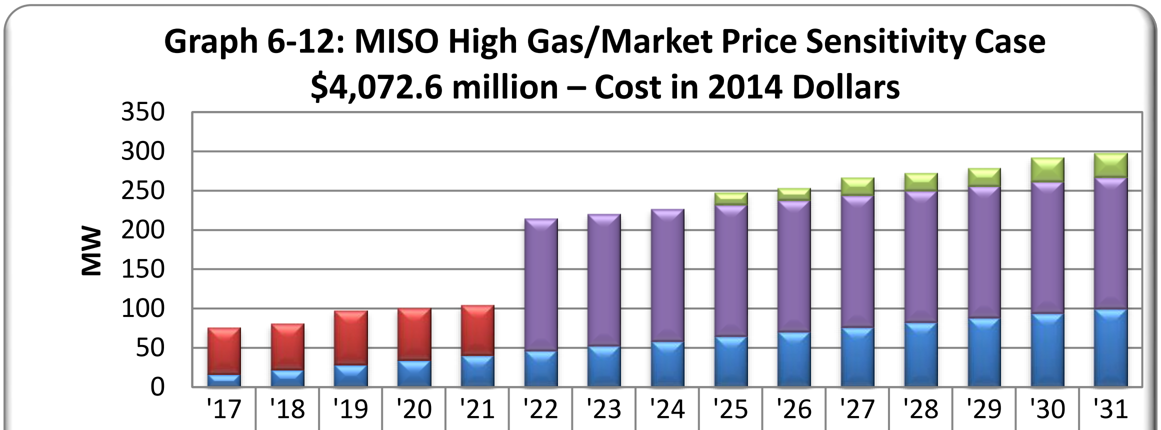
The remaining sensitivity cases for MISO indicate that the Base Case shows limited sensitivity to most of the alternative variables studied. The variables have only slight impact on the MISO expansion capacity portfolio, with the exception of the expected conservation case, all as described below.

6.2.3. MISO High Gas & Market Price Sensitivity Case

This sensitivity case evaluates the impact of both high natural gas and electric market prices, using the Base Case cost of $21.50 for CO_2 emissions.

<u>MISO High Gas/Market Price Sensitivity</u>. The modeling for this alternative case required the variation of the following assumption, as compared to the Base Case:

o Market & Natural Gas Prices: **High Gas & Market Costs**



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind									15.0	15.0	22.5	22.5	22.5	30.0	30.0
Future CT						168	168	168	168	168	168	168	168	168	168
Purchase	59.0	58.0	69.0	66.0	64.0										
DSM/CIP	16.9	22.6	28.5	34.7	40.8	46.9	52.9	58.9	64.9	70.9	76.8	82.6	88.5	94.3	100

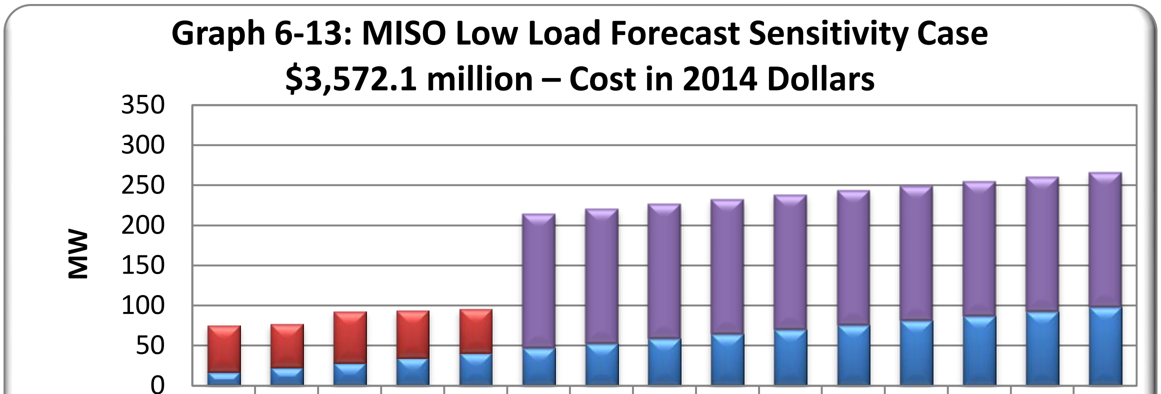
The MISO Gas and Market Price sensitivity case demonstrates that higher commodity prices will require the addition of some renewable resources in the 2025 through 2031 period, up to 30.0 MW of renewables (modeled as wind) over the Base Case. The corresponding increase in the overall cost of the expansion plan is about $261 million.

6.2.4. MISO Load Forecast Uncertainty Sensitivity Cases

These sensitivity cases were modeled to evaluate the impact of both lower than expected load growth and higher than expected load growth.

<u>MISO Low Load Forecast Sensitivity</u>. The low load sensitivity case differs from the Base Case assumption in one important way:

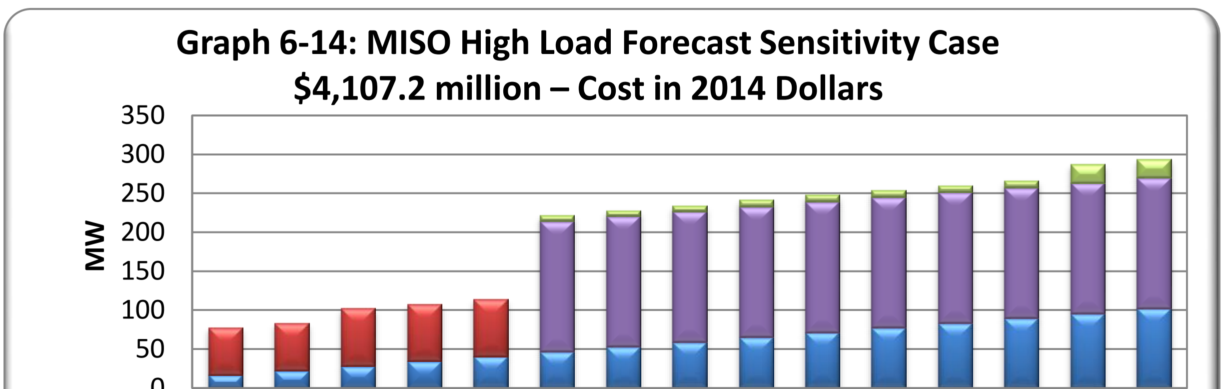
o Load Forecasts: **Low Load Forecast**



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Future CT						168	168	168	168	168	168	168	168	168	168
Purchase	58	54	64	59	55										
DSM/CIP	16.9	22.7	28.5	34.7	40.7	46.8	52.8	58.6	64.5	70.3	76.0	81.5	87.1	92.6	98.1

MISO High Load Forecast Sensitivity. The high load sensitivity case also differs from the assumptions of the Base Case:

- Load Forecasts: **High Load Forecast**



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind						7.5	7.5	7.5	9	9	9	9	9	24	24
Future CT						168	168	168	168	168	168	168	168	168	168
Purchase	61	61	74	73	73										
DSM/CIP	16.9	22.7	28.5	34.7	40.8	47.0	53.1	59.3	65.4	71.5	77.7	83.8	89.8	96.0	102.

The MISO Low and High Load Forecast Sensitivity cases demonstrate some change compared to the MISO Base Case. The Low Sensitivity has the same resource additions at a slightly lower cost, and the High Sensitivity results in additional resources in the form of purchases in the short term and additional with a cost increase of $296 million.

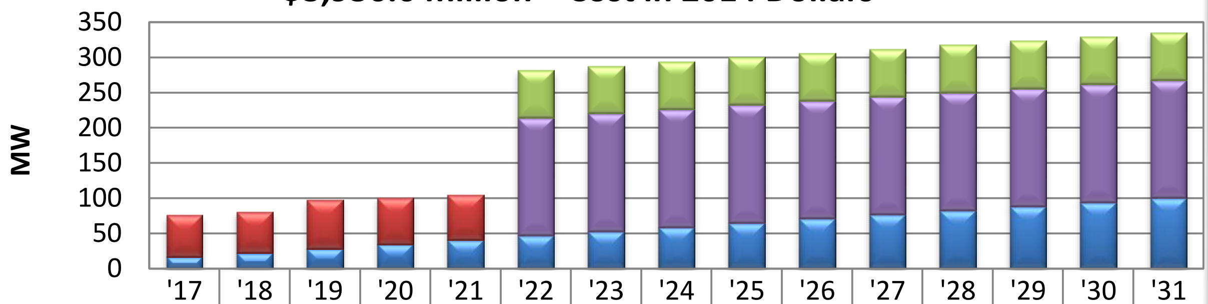
6.2.5. MISO Renewable Sensitivity Cases

Unlike the SPP Base Case, the MISO Base Case includes fossil-fuel resource additions. For this reason, it is necessary to complete a sensitivity case that relies primarily on renewable and non-emitting resources. In these sensitivity cases, as compared to the MISO Base Case, at least 50% or 75% of future resources are supplied by renewable resources (wind or conservation).

<u>MISO 50% Renewable Sensitivity.</u> This alternative case varies from the Base Case as follows:

- Other Assumptions: **50% Renewable Capacity Added**

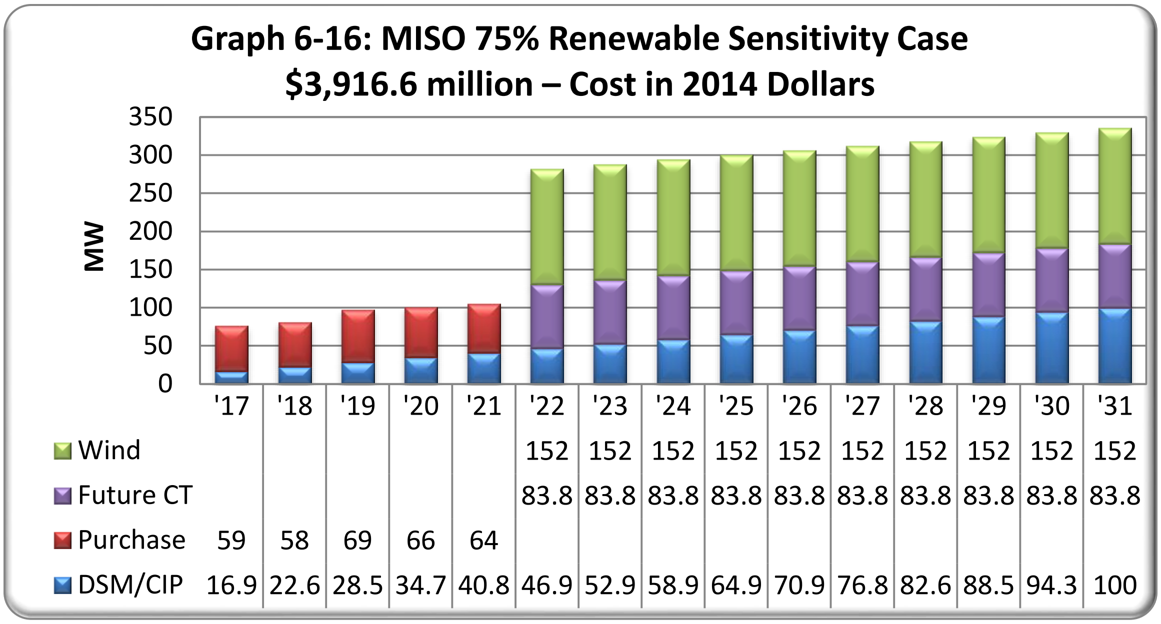
Graph 6-15: MISO 50% Renewable Sensitivity Case
$3,936.6 million – Cost in 2014 Dollars



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind						67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5
Future CT						168	168	168	168	168	168	168	168	168	168
Purchase	59	58	69	66	64										
DSM/CIP	16.9	22.6	28.5	34.7	40.8	46.9	52.9	58.9	64.9	70.9	76.8	82.6	88.5	94.3	100

<u>MISO 75% Renewable Sensitivity</u>. This alternative case varies from the Base Case as follows:

- Other Assumptions: **75% Renewable Capacity Added**



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind						152	152	152	152	152	152	152	152	152	152
Future CT						83.8	83.8	83.8	83.8	83.8	83.8	83.8	83.8	83.8	83.8
Purchase	59	58	69	66	64										
DSM/CIP	16.9	22.6	28.5	34.7	40.8	46.9	52.9	58.9	64.9	70.9	76.8	82.6	88.5	94.3	100

The 50% Renewable sensitivity case requires more resources at a slightly higher cost in comparison to the MISO Base Case. Specifically, while the Base Case requires the addition of a total of 267.8 MW of supply and demand-side resources, the 50% Renewable Sensitivity case requires 335.5 MW, and the incremental increase of 67.5 MW in resource additions is represented entirely by renewables (modeled here as wind capacity). Together with the 100 MW of DSM/CIP, the 167.5 MW of renewables and conservation make up half of the resource additions. The 50% Renewable sensitivity case results in a cost increase of about $125 million over the MISO Base Case.

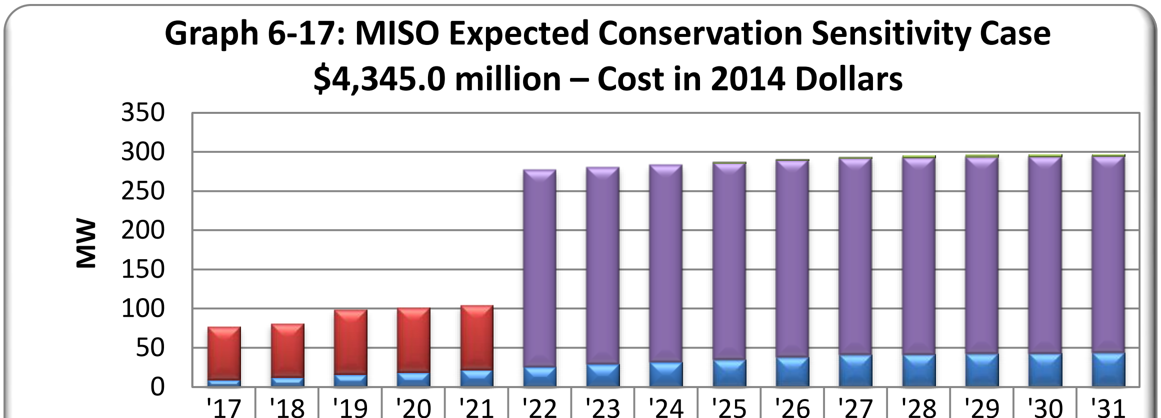
For the 75% Renewable sensitivity case, the modeling also requires 335.5 MW of additional resources, of which 252 MW (75%) is supplied by renewable resources and conservation. This case requires 152 MW of renewables (modeled here as wind capacity), together with 100 MW of DSM/CIP. This results in a cost increase of about $105 million.

6.2.6. MISO Expected Conservation Sensitivity Case

This sensitivity case evaluates the impact of including only the amounts that are feasible under the Morgan/Cadmus Study Program.

<u>MISO Expected Conservation Sensitivity</u>. This alternative case varies the following assumptions as compared to the Base Case:

- CIP Reductions: **Expected CIP**



	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31
Wind									1.5	1.5	1.5	3.0	3.0	3.0	3.0
Future CT						251	251	251	251	251	251	251	251	251	251
Purchase	67	68	82	82	82										
DSM/CIP	9.6	12.9	16.2	19.4	22.6	25.8	28.9	32	35.1	38.1	41.2	41.8	42.4	43	43.6

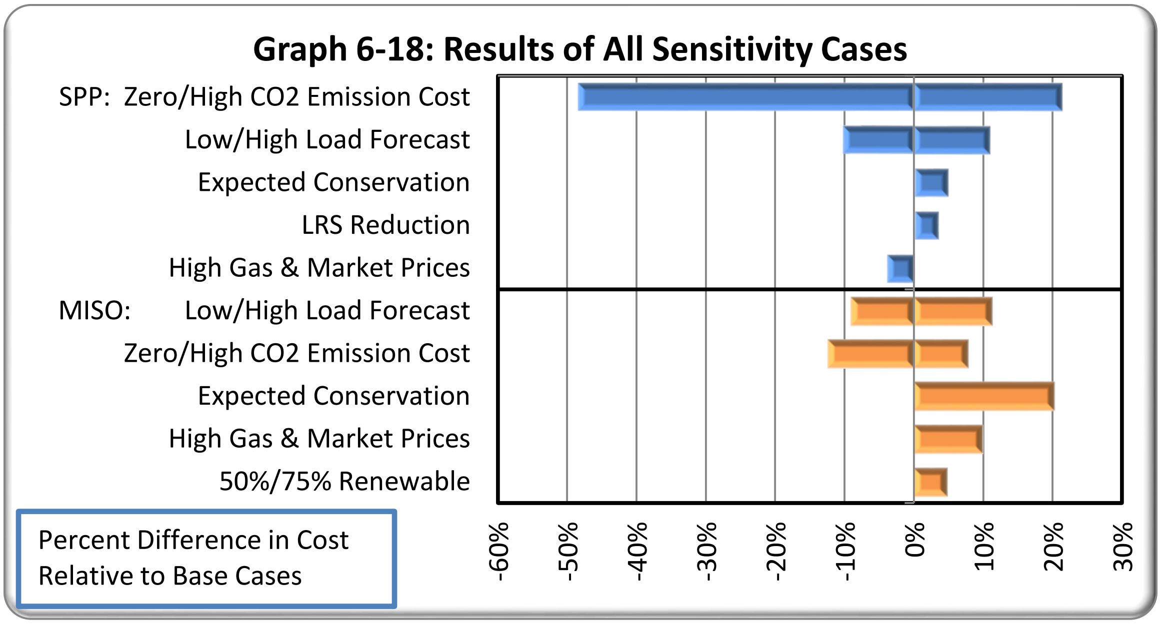
In MISO, the results of the Expected Conservation sensitivity case show that an additional peaking unit and some additional renewable resources would be required due to the higher loads under this sensitivity case. The added cost would be approximately $534 million. This case represents a possible outcome due to the significant difference between the results of the Morgan/Cadmus DSM study and the full CIP goals used in the other sensitivity cases.

6.3. Conclusions from the Sensitivity Analyses

The SPP Base Case, as well as all of the SPP sensitivity cases, show little need for additional capacity in SPP, beyond the DSM amounts in the study. This is consistent with the large amount of surplus capacity that MRES holds in that area. The SPP cases all show a need for a relatively small amount of wind resource in 2020 through 2031 to meet renewable objectives. Additional wind may be needed toward the end of the study in some sensitivity cases.

In MISO, the Base Case shows an almost immediate need for of capacity, and includes DSM as well as 168 MW of additional natural gas fired CT capacity by 2022. In the MISO sensitivity cases, the results may add wind capacity or modify the amount of CT capacity included.

As the graph below illustrates, the relative costs compared to the Base Cases vary considerably in SPP for the CO_2 emission cost sensitivity cases. Overall load growth is the second highest sensitivity factor. While the MISO cases overall do not show as much of a sensitivity difference, the primary drivers are the overall load growth, CO_2 emission costs, and the potential impact of failing to achieve the full 1.5% conservation goals.



The remaining sensitivity cases have relatively less impact on long-term costs (less than 20% on an overall present-worth basis). This demonstrates that the case work and results are relatively robust, even under a variety of alternative assumptions.

To summarize the results of the sensitivity cases, this additional modeling supports the following conclusions:

1. MRES should continue efforts to address its shortfall of capacity in MISO, meet the RES and renewable goals, and implement DSM.

2. MRES future costs in SPP are highly linked to future CO_2 emission charges. Compared to zero CO_2 emission costs, the base case or high CO_2 emission cost assumptions increase costs considerably. MRES should continue to be vigilant in managing its exposure to CO_2 costs.

3. To a lesser degree, increased loads can have an impact on overall costs in both RTO areas, as shown by the both the High Load Forecast and Expected Conservation sensitivity cases.

4. MRES costs are relatively insensitive to natural gas and electricity market prices (especially in SPP), and to a reduction in LRS capability. The excess of base-load and natural-gas resources in the SPP region means that changes in market prices have a similar and opposite impact on energy purchased to serve load and on energy produced from resources.

Based on this information, the prudent course of action for MRES suggests that future resource planning should:

- Continue to minimize the risk of future CO_2 emission costs.
- Continue to minimize growth of existing load by persisting in efforts to increase coincident peak demand reductions and overall conservation efforts. The "Expected Conservation" sensitivity case illustrates that an inability to achieve the full CIP amounts of conservation reduction will result in the need for an additional 167 MW of peaking capacity in MISO beyond the Base Case results.
- Continue to market surplus capacity in the SPP region.
- Continue to reduce market price risk by reducing the capacity shortfall in MISO with a reasonable amount of fixed-cost supply. This includes continued efforts to implement DSM and to meet the Minnesota RES, while also investigating peaking capacity options (including capacity purchases) to meet the MISO capacity shortfall.

While the optimal results from the plan indicate the need for additional capacity, MRES does not have current plans to site or construct a large energy facility in Minnesota as a result of the modeling effort.

6.4. Plan is in the Public Interest

This IRP furthers the public interest because it provides a deliberate plan to ensure that MRES is able to continue to meet the needs of its Members for electricity to power their communities for the long-term. It is also sensitive to the fact that electricity must be affordable for all consumers. Finally, both the cost and the reliability of electricity are balanced with the important task of delivering these services in a manner that is environmentally responsible. These objectives are an inherent part of the resource planning process for MRES, as demonstrated by the foregoing planning process and outcomes.

6.4.1. Public Power Objectives are consistent with the Public Interest

MRES is a municipal power agency, founded on the principles of public power and the collective benefits of joint action. MRES exists to serve the needs of its municipal electric utility Members, and their consumer-owners. Indeed, MRES was created, and is governed, by its Members as a not-for-profit utility. The mission of MRES is to provide to its Members reliable, cost-effective, and environmentally sensitive power supply, and these objectives are inherently in harmony with the public interest. MRES does not have any financial incentive to invest in additional resources for any purpose other than to serve its Members in a reliable manner.

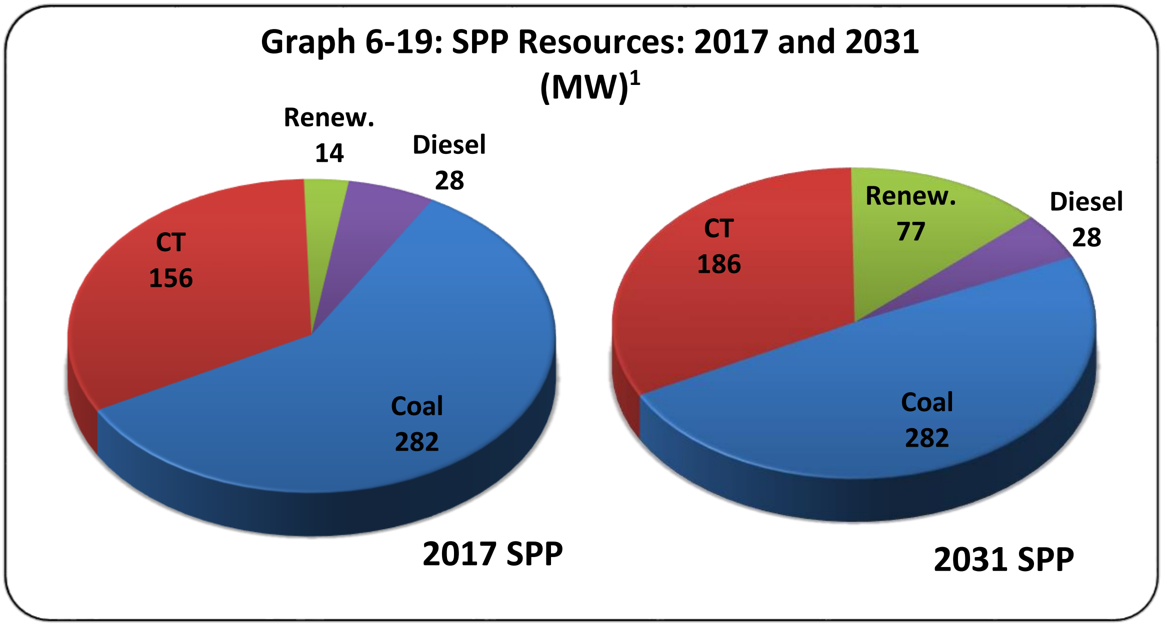
The principles of joint action that underpin the MRES resource planning process are reflected in Minnesota's public policy. By providing "an adequate, economical, and reliable supply of electric energy [which] is essential to the orderly growth and prosperity of [those] communities" that own and operate electric distribution utilities, and "limiting environmental impacts," this plan meets policy goals articulated by the Legislature decades ago. Minn. Stat. § 453.51.

6.4.2. The Plan is Consistent with Socioeconomic and Environmental Policy Goals

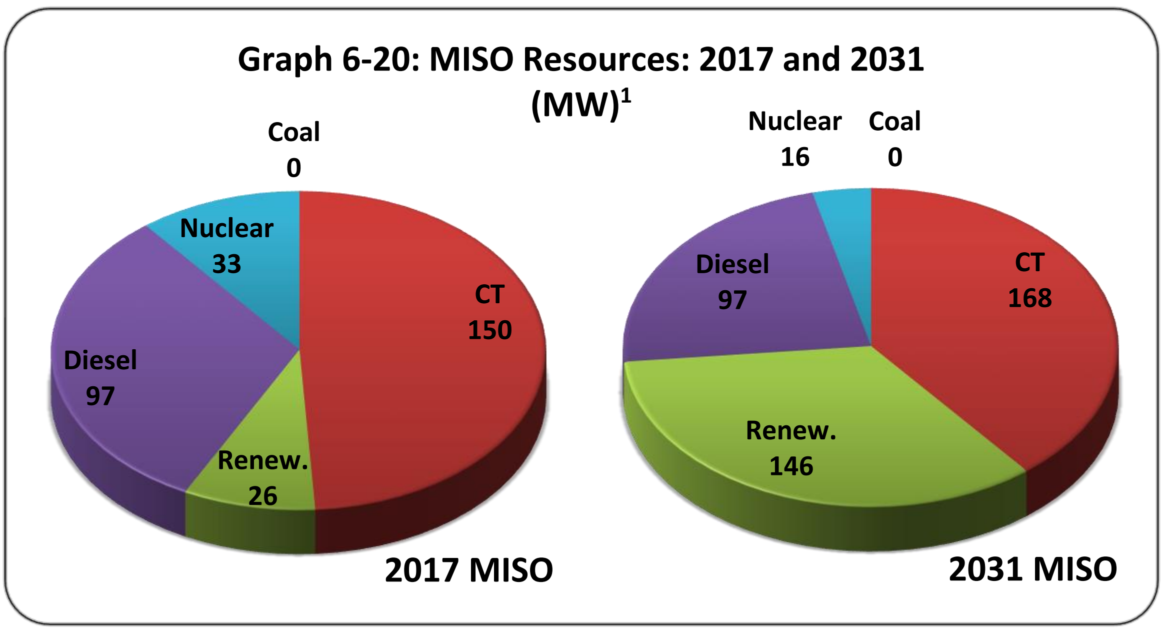
The results of the planning over the entire study period demonstrate that DSM and renewable resources are optimal choices to meet the need for additional resources for MRES to serve the ongoing needs of its Members. In addition, some combination of peaking capacity or capacity purchases will be necessary to meet the MRES capacity shortfall in the MISO region. These outcomes are essential to ensure that MRES continues to meet the requirements of Minn. Stat. § 216B.1691 to include renewable resources as a significant portion of its resource mix serving Minnesota consumers specifically.

Likewise, pursuing both the short-term and long-term objectives identified in this IRP also ensures that MRES is doing its part to help the State of Minnesota meet its policy objectives to reduce greenhouse gases embodied in Minn. Stat. § 216H. Notably, the MRES resource plan results demonstrate that future resource needs will rely heavily on growing DSM and non-emitting generating resources, and the only carbon-based resource additions identified as economical rely on low-emitting natural gas. It is also worthy of note that 21 of the 24 MRES Members in Minnesota are located in the MISO region, and MRES no longer has transmission to serve the majority of its Minnesota load with its base-load coal resource, LRS.

The following charts for the SPP and the MISO Base Cases show increasing amounts of DSM and renewables over time and significantly less dependence on thermal resources.



[1] Accredited ratings; Renewable includes DSM



[1] Accredited ratings; Renewable includes DSM

Specifically, the Resource Plan is in the public interest because:

- It maintains the adequacy and reliability of utility service by ensuring additional capacity is added as needed to meet customer requirements. A primary objective of the modeling process is to ensure capacity requirements are met every year.

- It helps keep MRES Member utilities' rates, and the bills of their customer-owners, as low as practicable, given regulatory and other constraints. The primary outcome used to determine the optimal plan is the overall minimum cost, including environmental costs (while meeting adequacy and reliability requirements), and that will ensure the overall lowest rates to consumers.

- It allows MRES to meet the Minnesota renewable energy standard in Minn. Stat. § 216B.1691.

- It minimizes adverse effects on the environment. Emission externality and allowance costs for any new resources are included as integral elements of the economic analysis, and both DSM and conservation effects are included in the load and resource modeling. The potential effects of various CO_2 emission costs were evaluated in several sensitivity cases. For Minnesota, the resulting increase in renewable resources helps to achieve the state's greenhouse gas reduction goals of Minn. Stat. § 216H.02.

- It limits the risk of adverse effects on MRES, its Members and their customers from financial, social, and technological factors that the utility cannot control. As the sensitivity analysis shows, the results are very robust, even under many alternative risk assumptions.

6.5. Renewable Energy Cost Impact

Minnesota law requires each electric utility to estimate the cost of complying with the state's renewable energy objectives and renewable energy standard (RES) by estimating the rate impact of acquiring renewable resources.[30] Those activities include energy purchases, generation facility construction and/or acquisition, and dedicated transmission improvements. The Commission developed a uniform system for utilities to use when estimating and reporting the rate impacts.[31] This uniform method provides further guidance as to the types of costs that are to be included and the years to be covered by the reports. Based on this analysis, MRES has determined that the historic cost to comply with the RES was $1.98/MWh, and the future anticipated rate impact is $3.76/MWh from 2016 through 2031. The MRES RES rate impact report is provided in Appendix K.

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[30] Minn. Stat. § 216B.1691, subd. 2e.

[31] "*Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat. § 216B.1691*," Minnesota Public Utilities Commission, Docket No. E-999/CI-11-852, dated January 6, 2015.

6.6. Determine Short-Term and Long-Term Action Plans

The SPP and MISO Base Case results indicate the need to add approximately 170 MW of generating capacity, including a combination of CT resources and capacity purchase agreements. MRES also needs to add 177 MW of conservation and wind resources to meet the Minnesota RES, achieve the conservation reductions to meet the full Minnesota CIP requirements, and to meet the 10% renewable goals assumed for Member load in Iowa, North Dakota and South Dakota. These amounts are in addition to the RRHP project currently under construction. No other resources are necessary under the Base Case expansion plans.

The sensitivity cases showed that, of the factors considered, the costs of CO_2 emissions has the greatest potential to adversely affect MRES rates.

6.6.1. Five Year, Short-Term Action Plan (2016-2020)

During the next five years, MRES will continue its efforts to address its capacity shortfall in the MISO market. This includes completion of the Red Rock Hydroelectric Project, and obtaining peaking capacity. Efforts to secure additional peaking capacity will include pursuing agreements with potential capacity suppliers, and investigating new peaking capacity projects.

Another priority for MRES is continuing efforts to assist Members with implementation of their DSM and conservation activities. For the Minnesota Members, this means maintaining concerted activities to pursue DSM measures to meet the Minnesota CIP requirements. Appendix H details activities underway to support these efforts.

Wind or other renewable resources will continue to be obtained to ensure the MRES resource mix provides renewable energy to serve MRES Members and their consumer-owners. The MRES Board of Directors is committed to compliance with the Minnesota RES, as well as the 10% renewable goals in its other Member states.

Another important element of the MRES short-term action plan includes continuing active efforts to participate in federal and state activities to establish and implement regulations to reduce CO_2. MRES efforts are designed to ensure a reasonable and balanced approach to carbon reduction, while minimizing potential adverse economic impacts of various forms of CO_2 emission regulations. This element ensures the priority of the MRES mission to maintain a cost-effective power supply program and to ensure environmental stewardship.

Although no plans are anticipated at this time to site or construct a large energy facility to implement the short-term action plan, such a need may develop as the investigation process proceeds.

6.6.2. Long-Term Action Plan (2021-2031)

MRES has a need for additional capacity and a small amount of additional renewable capacity in the short term as indicated above. Once that need is met, under SPP and MISO Base Case conditions, additional needs may be met through further development of DSM and conservation activities. In addition, MRES will obtain additional renewable energy resources during this time period to continue to meet the RES.

To the extent conditions do not follow the expected Base Case conditions, the resource plan will need to be altered accordingly. MRES will continue to periodically update its resource plan and adjust the long-term action plan as appropriate.

Part VII: Appendices

A – Plan Cross-Reference

B – Historical Reports

C – 2016 S-1 Rate Schedule

D – EIA-861 Filings

E – Short-Term Load Forecast

F – Long-Term Load Forecast

G – Minnesota Member Load Forecasts

H – Morgan/Cadmus DSM Potential Study 2015-2039 Final Report

I – EVA Modeling Overview

J – MRES Environmental Matrix

K – Renewable Energy Cost Impact Report

L – RES Progress Since Previous Resource Plan Filing

Appendix A: Plan Cross-Reference

Table A-1 Cross-reference of Resource Plan requirements		
Statute, Rule, Order	**Requirement**	**Reference Section**
§216B.1691, subd. 2e; Order Establishing Uniform Reporting System for Estimating Rate Impact[1]	Submit report estimating rate impact of activities necessary to comply with the RES. Include Rate Impact Report as Appendix to IRP, and identify in Table of Contents.	Appendix K
§216B.1691, subd. 3	Report on plans and progress toward meeting RES in resource plans and/or every two years	Appendix L
§216B.2422, subd. 2	Include least-cost plans for meeting 50% and 75% of all new and refurbished capacity needs with conservation and renewable energy	Plan Section 6.2.5
§216B.2422, subd. 2a	Include applicable annual information (long-term load forecasts) required by §216C.17, subd. 2	Appendices B, F, and G
§216B.2422, subd. 2c MPUC Notice of Information in Future Resource Plan Filings[2]	Include narrative regarding utility's ability to make progress toward achieving state greenhouse gas (GHG) emission reduction goals established in §216H.02, subd.1, and efforts being considered to address those opportunities and barriers. Include explanation how the resource plan helps the utility achieve state GHG goals and RES.	Plan Sections 1.2.4, 1.2.5, 1.2.6 Plan Section III Plan Section 6.4
§216B.2422, subd. 3	Use the environmental externality cost values, along with other socioeconomic factors, in selecting resources.	Plan Section 5.1.3, Study Goal 3
§216B.2422, subd. 4	Utility must show that any proposed new or refurbished nonrenewable energy facility is in the public interest and that a renewable energy facility is not in the public interest. The public interest determination must include whether the resource plan helps the utility achieve the GHG reduction goals (§216H.02), and the RES (§216B.1691).	Plan Section 6.4
§216B.2422, subd. 6	Identify whether utility intends to site or construct a large energy facility.	Plan Section 6.6.1

[1] "Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat. § 216B.1691," Minnesota Public Utilities Commission, Docket No. E-999/CI-11-852, January 6, 2015.

[2] See "Notice of Information in Future Resource Plan Filings," Minnesota Public Utilities Commission, *In re Minnesota Power's 2013-2028 Integrated Resource Plan*, Docket No. E-015/RP-13-53, August 5, 2013.

Table A-1 Cross-reference of Resource Plan requirements		
Statute, Rule, Order	**Requirement**	**Reference Section**
7610.0130	Details additional filing requirements under Minn. R. 7610	See next 3 Lines of This Table
7610.0120	Update the utility's registration statement	Appendix B
7610.0170	Identify energy-related forms and reports the utility regularly files with FERC, DOE and other federal agencies	Appendix B (identify) Appendix D (copies)
7610.0600, items B to J	Include reports of specified information regarding load and service area information for a recent time period	Appendices B, F
7843.0300, subp. 5, and 7843.0300, subp. 13	Submit 15 copies of the plan to the Commission, and copies to the Department, Attorney General, MEQB, and other interested parties on the official service list. *MRES consulted with staff of the Commission and Department on the continuing applicability of these rules, and were advised that electronic filing of Public and Trade Secret versions of the plan are adequate to meet 7843.0300, subp. 5, which has not been updated since 2005. Staff also noted that with e-filing physical copies are no longer necessary for service and filing. At their request, MRES will submit a paper copy/copies of the Trade Secret Version for Commission staff (1) and Department staff (3).*	Official filing, Affidavit of Service, and Service List
7843.0400, subp. 2, Sentence 2	Show resource options that might meet customers' needs over forecast period	5.4
7843.0400, subp. 2, Sentence 3	Show how resource plans vary with changes in supply and demand	5.5
7843.0400, subp. 2, Sentence 5	Discuss any plans to reduce existing resources	5.5
7843.0400, subp. 3(A)	Include complete list of resource options considered, with supporting information	5.4
7843.0400, subp. 3(B)	Describe overall process and analytical techniques used to create the plan	Plan Section V
7843.0400, subp. 3(C)	Include a five-year action plan, including plans to acquire resources and key activities to do so	6.6.1
7843.0400, subp. 3(D)	Discuss why the plan is in the public interest	6.4
7843.0400, subp. 4	Includes a separate, non-technical summary not exceeding 25 pages in length.	Plan Section II

Appendix B: Reports Required by Minn. R. 7610.0130

Overview

Several informational items must be provided with this filing as established in Minn. R. 7610.0130, subpart 1. This section provides the required historical information concerning MRES and its members' loads. This Appendix B includes the following information:

- Registration Information
- Federal Reports
- Customers over 10,000 MWh
- Detailed maps of service area, generation, transmission lines over 200 kV and substations
- List of purchases and sales with other utilities
- Rate Schedule
- EIA-861
- Generation Information
- Residential electric space heating information
- Deliveries to ultimate consumers and revenues

Registration Information

Minnesota Rule Part 7610.0120 requires that registration information be updated as part of each utility's report. This information appears below, and includes the name and headquarters address of the utility, and the names, addresses, and telephone numbers of the officers of the utility.

MRES Headquarters:[1]

Missouri River Energy Services
PO Box 88920
3724 West Avera Drive
Sioux Falls, SD 57109-8920
Phone: (605) 338-4042
Fax: (605) 334-9753

Western Minnesota Headquarters:

Western Minnesota Municipal Power Agency
25 NW 2nd Street, Suite 102
Ortonville, MN 56278
Phone: 320-839-2549
Fax: 320-839-2540

[1] Note that, pursuant to an administrative services agreement between the parties, MRES acts as agent for Western Minnesota and provides all of its staffing needs at the MRES Headquarters.

Officers of the MRES Board of Directors:

Chairman
Harold Schiebout
335 1st Avenue, NW
Sioux Center, IA 51250-1814

1st Vice Chairman
Don Johnston
PO Box 343
Flandreau, SD 57028-0343

2nd Vice Chairman
Bill Schwandt
PO Box 779
Moorhead, MN 56561

3rd Vice Chairman
James Hoye
310 S. 3rd Ave
Rock Rapids, IA 51246-1631

4th Vice Chairman
Norris Severtson
512 2nd St. E
Lakota, ND 58344

Secretary/Treasurer
Brad Roos
113 4th Street South
Marshall, MN 56258-1223

Officers of the Western Minnesota Board of Directors:

President
Bill Schwandt
PO Box 779
Moorhead, MN 56561

Vice President
Allen Crowser
PO Box 609
Alexandria, MN 56308

Secretary
Scott Hain
PO Box 458
Worthington, MN 56187

Treasurer
Vernell Roberts
PO Box 647
Detroit Lakes, MN 56502

Assistant Secretary and Assistant Treasurer
Tom Heller
P.O. Box 88920
Sioux Falls, SD 57109-8920

Assistant Secretary
Merlin Sawyer
P.O. Box 88920
Sioux Falls, SD 57109-8920

Second Assistant Secretary
Ray Wahle
P.O. Box 88920
Sioux Falls, SD 57109-8920

Assistant Secretary and Assistant Treasurer

Primary Staff Contacts for MRES and Western Minnesota can be reached at the MRES Headquarters. Their names and titles are:

- Tom Heller, Chief Executive Officer
- Deb Birgen, Director, Legislative Government Relations
- Joni Livingston, Director, Member Services and Communications
- Jeff Peters, Director, Federal & Distributed Power Programs Department
- Merlin Sawyer, Director, Finance and Chief Financial Officer
- Mrg Simon, Director, Legal Department
- Ray Wahle, Director, Power Supply and Operations

Federal Reports

Minnesota Rule Part 7610.0170 requires that utilities identify all energy-related forms and reports that MRES regularly files with the Federal Energy Regulatory Commission, the United States Department of Energy, the Rural Electrification Administration (MRES makes no filings with the Rural Electrification Administration), and other federal agencies.

MRES files the following federal reports and forms annually:

1. Form EIA-860, Energy Information Administration, "Annual Electric Generator Report."
2. Form EIA-861, Energy Information Administration, "Annual Electric Utility Report."
3. Form EIA-923M, Energy Information Administration, "Power Plant Operations Report - Monthly."
4. Form EIA-923A, Energy Information Administration, "Power Plant Operations Report - Annual."

Customers Over 10,000 MWh Annually

Minnesota Rule Part 7610.0600, item B requires the names, addresses, and the kilowatt hours of electricity consumed by customers of the utility who annually consume over 10,000 megawatt hours.

Table B-1, below, shows the 2015 annual energy for each of the members. Table B-2 shows their summer 2015 and winter 2014-15 peak demands. All MRES Minnesota member cities, with the exception of Henning, Lake Park, and Westbrook, purchased over 10,000 MWh from MRES and WAPA in 2015, as shown in Table B-1. The addresses of all MRES Minnesota members are provided in Table B-3.

Table B-1
2015 Electrical Energy Purchases by Members
Values in kWh, Town Gate

Iowa Member	Total Energy	MRES Energy	% MRES [1]
Alton	11,363,289	4,236,289	37.28%
Atlantic	113,588,776	8,760,000	7.71%
Denison	164,032,590	88,106,590	53.71%
Hartley	20,340,550	5,400,550	26.55%
Hawarden	27,084,080	5,254,640	19.40%
Kimballton	2,434,737	276,968	11.38%
Lake Park	12,947,600	5,124,600	39.58%
Manilla	7,427,090	1,044,471	14.06%
Orange City	86,173,164	54,497,164	63.24%
Paullina	10,610,217	3,291,217	31.02%
Pella	190,625,068	190,625,068	100.00%
Primghar	9,424,899	3,606,899	38.27%
Remsen	16,431,726	5,961,726	36.28%
Rock Rapids	28,793,708	7,920,708	27.51%
Sanborn	24,146,268	12,989,268	53.79%
Shelby	6,672,834	2,472,834	37.06%
Sioux Center	124,770,174	92,835,174	74.40%
Woodbine	16,088,986	5,843,986	36.32%
Subtotal:	872,955,756	498,248,152	57.08%

Minnesota Member	Total Energy	MRES Energy	% MRES [1]
Adrian	13,996,173	5,157,173	36.85%
Alexandria	293,795,416	197,516,416	67.23%
Barnesville	24,190,472	12,393,472	51.23%
Benson	36,197,213	9,328,213	25.77%
Breckenridge	40,911,096	12,010,096	29.36%
Detroit Lakes	193,610,194	123,955,194	64.02%
Elbow Lake	18,116,987	8,521,987	47.04%
Henning	9,398,088	4,560,088	48.52%
Hutchinson [2]	302,057,000	219,000,000	72.50%
Jackson	49,007,824	23,927,824	48.82%
Lake Park	8,670,536	5,069,536	58.47%
Lakefield	14,449,841	3,522,841	24.38%
Luverne	83,976,905	36,186,905	43.09%
Madison	18,340,027	4,120,693	22.47%
Marshall	595,174,333	34,498,731	5.80%
Melrose	115,176,246	80,208,246	69.64%

Moorhead	445,688,831	218,489,831	49.02%
Ortonville	29,732,638	6,525,638	21.95%
Sauk Centre	62,870,371	38,148,371	60.68%
St James	56,642,430	20,791,430	36.71%
Staples	23,112,000	16,545,000	71.59%
Wadena	71,631,000	28,827,000	40.24%
Westbrook	7,655,518	495,973	6.48%
Worthington	221,705,425	163,326,425	73.67%
Subtotal:	2,736,106,564	1,273,127,083	46.53%

North Dakota Member	**Total Energy**	**MRES Energy**	**% MRES [1]**
Cavalier	18,883,872	1,871,312	9.91%
Hillsboro	29,333,857	14,662,857	49.99%
Lakota	15,126,973	4,583,973	30.30%
Northwood	19,902,240	8,759,240	44.01%
Riverdale	3,316,118	1,228,118	37.03%
Valley City	110,444,496	33,658,774	30.48%
Subtotal:	197,007,556	64,764,274	32.87%

South Dakota Member	**Total Energy**	**MRES Energy**	**% MRES [1]**
Beresford	29,680,857	17,410,857	58.66%
Big Stone City	13,191,375	3,361,375	25.48%
Brookings	322,825,685	219,206,685	67.90%
Burke	7,479,660	1,499,880	20.05%
Faith	6,362,753	379,850	5.97%
Flandreau	28,945,113	14,354,113	49.59%
Fort Pierre	26,156,093	13,690,093	52.34%
Pickstown	2,733,371	1,220,371	44.65%
Pierre	181,894,388	67,491,388	37.10%
Vermillion	67,263,487	25,314,487	37.63%
Watertown	390,237,111	266,292,111	68.24%
Winner	41,464,497	9,311,219	22.46%
Subtotal:	1,118,234,390	639,532,429	57.19%
Grand Total:	**4,924,304,266**	**2,475,671,938**	**50.27%**[3]

[1] The column titled “% MRES” reflects the percentage of each Member’s energy that is supplied by MRES.

[2] The Total for Hutchinson is an estimate. MRES does not collect the total data for Hutchinson, as MRES sells a flat amount to Hutchinson in all hours.

[3] The Grand Total for the column titled “% MRES” represents the average percentage of all MRES Members’ energy that is supplied by MRES.

Table B-2
Summer 2015 and Winter 2014-15 Member Peak Demands
Total Demands in kW, Town Gate

Iowa Member	Summer 2015	Peak Month	Winter 2014-15	Peak Month
Alton	2,470	Oct	2,812	Jan
Atlantic	23,865	Jul	21,969	Jan
Denison	29,041	Jul	26,949	Jan
Hartley	3,834	Jul	4,143	Jan
Hawarden	6,105	Jul	4,891	Dec
Kimballton	556	Jul	668	Jan
Lake Park	2,838	Jul	2,438	Dec
Manilla	1,579	Jul	1,690	Jan
Orange City	18,670	Sep	14,847	Jan
Paullina	2,406	Jul	1,878	Jan
Pella	43,914	Jul	32,020	Jan
Primghar	2,031	Jul	1,793	Jan
Remsen	3,645	Jul	3,224	Dec
Rock Rapids	6,534	Jul	5,213	Jan
Sanborn	4,212	Jul	4,360	Dec
Shelby	1,420	Jul	1,537	Dec
Sioux Center	25,007	Jul	21,187	Dec
Woodbine	3,518	Jul	3,758	Feb

Minnesota Member	Summer 2015	Peak Month	Winter 2014-15	Peak Month
Adrian	2,929	Sep	2,988	Jan
Alexandria	56,224	Jul	47,107	Jan
Barnesville	4,044	Jul	5,605	Feb
Benson	6,989	Jul	6,546	Jan
Breckenridge	7,518	Sep	9,156	Jan
Detroit Lakes	35,763	Aug	35,562	Jan
Elbow Lake	2,939	Jul	4,157	Feb
Henning	1,748	Aug	2,052	Jan
Hutchinson [1]	58,500	Sep	42,600	Jan
Jackson	10,575	Jul	9,022	Jan
Lake Park	1,452	Aug	2,085	Jan
Lakefield	3,370	Jul	2,832	Dec
Luverne	17,200	Jul	16,340	Jan
Madison	3,878	Jul	3,747	Dec

Marshall	82,328	Jul	80,790	Feb
Melrose	17,872	Sep	18,971	Jan
Moorhead	80,998	Sep	77,537	Jan
Ortonville	5,684	Aug	6,122	Jan
Sauk Centre	11,221	Jul	12,000	Jan
St James	11,444	Jul	9,723	Jan
Staples	4,080	Aug	4,160	Jan
Wadena	11,432	Aug	13,819	Jan
Westbrook	1,451	Jul	1,478	Jan
Worthington	41,371	Sep	32,590	Jan

North Dakota Member	Summer 2015	Peak Month	Winter 2014-15	Peak Month
Cavalier	3,450	Aug	4,118	Jan
Hillsboro	4,328	May	7,600	Jan
Lakota	2,206	May	4,101	Jan
Northwood	3,259	May	5,564	Jan
Riverdale	807	Jul	737	Jan
Valley City	18,960	Sep	23,131	Dec

South Dakota Member	Summer 2015	Peak Month	Winter 2014-15	Peak Month
Beresford	6,388	Jul	6,004	Nov
Big Stone City	2,340	Sep	2,559	Jan
Brookings	58,020	Sep	56,914	Jan
Burke	1,632	Sep	1,955	Dec
Faith	1,171	Aug	1,574	Jan
Flandreau	5,819	Sep	5,236	Jan
Fort Pierre	5,846	Aug	5,298	Jan
Pickstown	650	Jul	810	Jan
Pierre	40,512	Aug	35,839	Jan
Vermillion	14,915	Jul	11,099	Jan
Watertown	72,849	Sep	66,479	Jan
Winner	8,049	Jul	10,600	Dec

[2] The amounts for Hutchinson are an estimate. MRES does not collect the total data for Hutchinson, as MRES sells a flat amount to Hutchinson in all hours.

Table B-3: MRES Member Cities in Minnesota

Adrian Public Utilities
P.O. Box 190
Adrian, MN 56110-0190
507-483-2849

Alexandria Light & Power
P.O. Box 609
Alexandria, MN 56308-01315
320-763-6501

Barnesville Municipal Utilities
P.O. Box 550
Barnesville, MN 56514-0550
218-354-2723

Benson Municipal Utilities
1410 Kansas Avenue
Benson, MN 56215-1718
320-843-4775

Breckenridge Public Utilities
P.O. Box 410
Breckenridge, MN 56520-0419
218-643-4681

Detroit Lakes Public Utilities
P.O. Box 647
Detroit Lakes, MN 56502-3637
218-847-7609

Elbow Lake Municipal Electric
P.O. Box 1079
Elbow Lake, MN 56531-1079
218-685-4483

Henning Municipal Utilities
P.O. Box 55
Henning, MN 56551-4054
218-583-2402

Hutchinson Utilities Commission
225 Michigan St SE
Hutchinson, MN 55350
320-587-4746

Jackson Municipal Utilities
80 W. Ashley Street
Jackson, MN 56143-1669
507-847-4410

Lake Park Public Utilities
P.O. Box 239
Lake Park, MN 56554-0239
218-238-5337

Lakefield Public Utilities
P.O. Box 1023
Lakefield, MN 56150-1200
507-662-6363

Luverne Municipal Utilities
P.O. Box 659
Luverne, MN 56156-0659
507-449-2388

Madison Municipal Utilities
404 6th Ave
Madison, MN 56256-1265
320-598-3239

Marshall Municipal Utilities
113 S 4th Street
Marshall, MN 56258-1223
507-537-7005

Melrose Public Utilities
225 E First St N.
Melrose, MN 56352-1153
320-256-4278

Moorhead Public Service Dept.
P.O. Box 779
Moorhead, MN 56561-0779
218-299-5404

Ortonville Municipal Utilities
315 Madison Ave
Ortonville, MN 56278-1325
320-839-3428

Saint James Public Utility
P.O. Box 70
St. James, MN 56081-1760
507-375-3241

Sauk Centre Public Utilities
P.O. Box 128
Sauk Centre, MN 56378-1344
320-352-6538

Staples Water & Light
122 6th Street NE
Staples, MN 56479-2224
218-894-2550

Wadena Electric & Water Dept.
104 N Jefferson Street
Wadena, MN 56482
218-631-7712

Westbrook Public Utilities
P.O. Box 308
Westbrook, MN 56183-1104
507-274-6712

Worthington Public Utilities
P.O. Box 458
Worthington, MN 56187-2382
507-372-8687

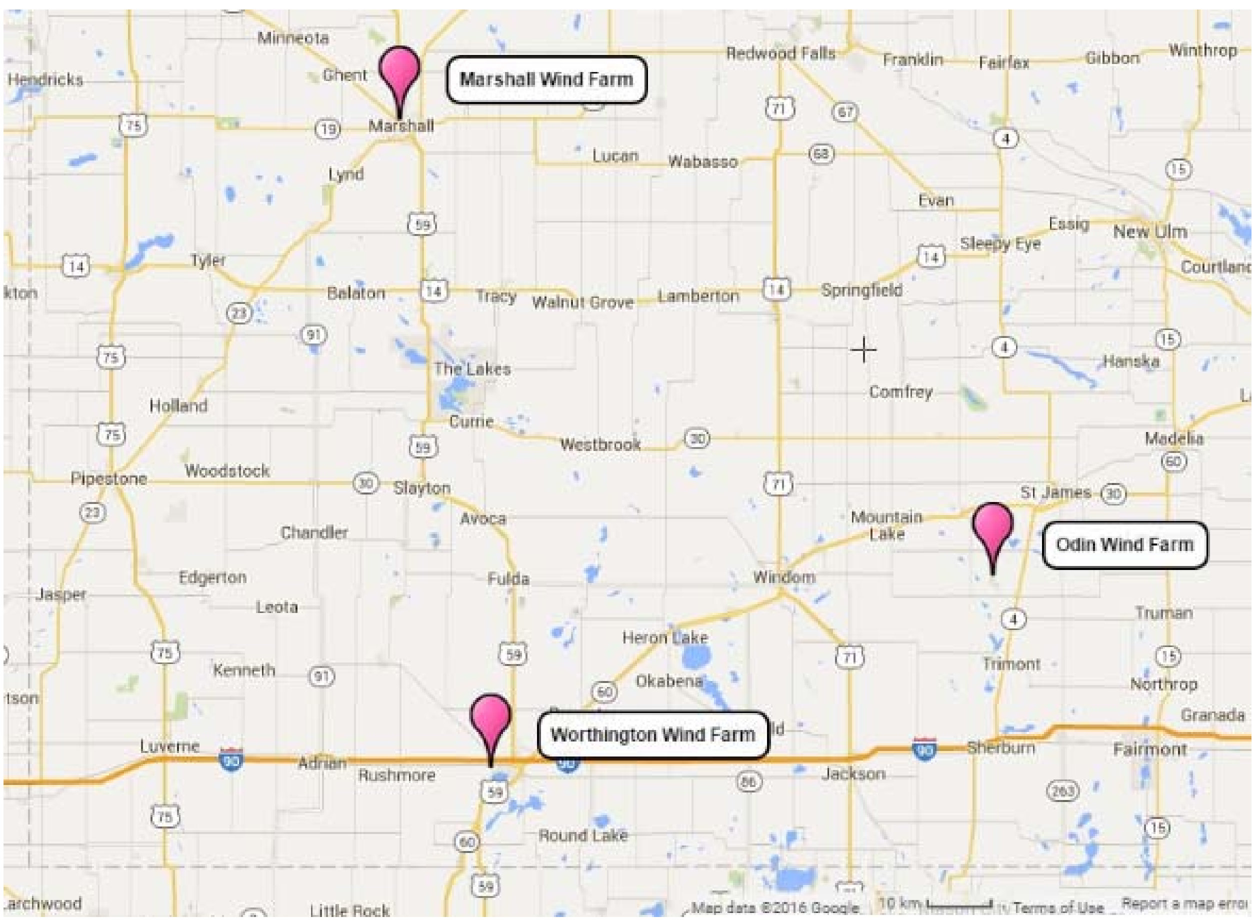
Map of Facilities in Minnesota

Minnesota Rule Part 7610.0600, item C requires "a detailed map, on which the scale is shown, of the utility's Minnesota service area, identifying power plants, principal substations, and transmission lines over 200 kilovolts, identified by voltage[.]"

MRES and Western Minnesota have no assigned service territories as they provide wholesale power supply, delivery, and energy services to Member municipal electric utility communities. Each of those Member communities has its own assigned service territory. Table B-3 (above) lists the names and addresses of the MRES Member utilities located in Minnesota.

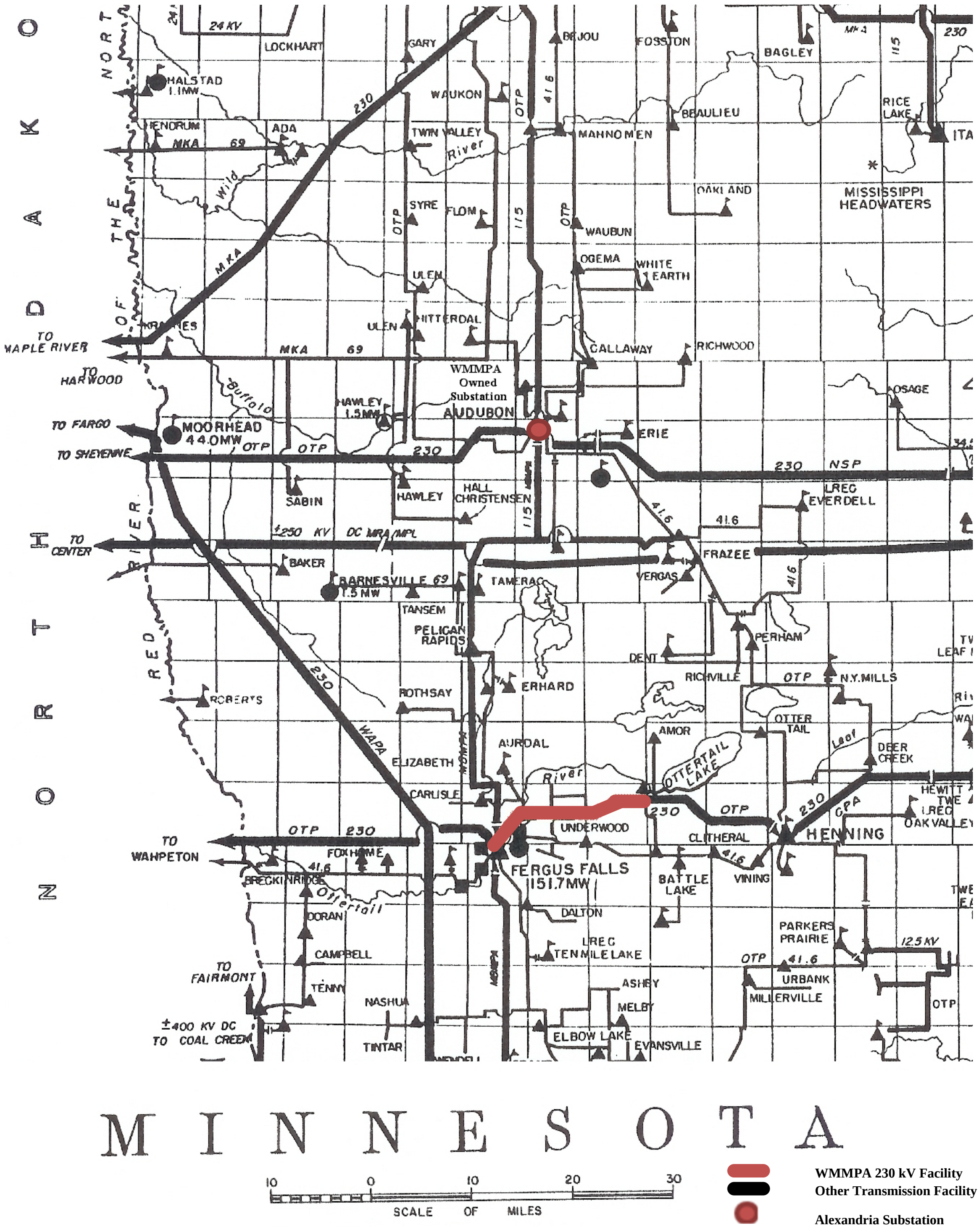
Western Minnesota owns four wind turbines located west of Worthington, as well as a small interest in wind turbines that are part of the Marshall Wind Farm and the Odin Wind Farm. Neither MRES nor Western Minnesota has any ownership interest in any other power generation plant in Minnesota. A map identifying the locations of these facilities, Figure B-1, is below.

Figure B-1: Map of WMMPA Power Plants – Wind Generation



Western Minnesota owns a small amount of high-voltage transmission operated at 230 kilovolts in the Otter Tail Power Company Local Balancing Area (LBA) in west central Minnesota. Those facilities consist of portions of the Fergus Falls and Audubon substations, and 10.97 miles of the Fergus Falls to Silver Lake to Henning (Minnesota) line. Figure B-2 is a map of these facilities.

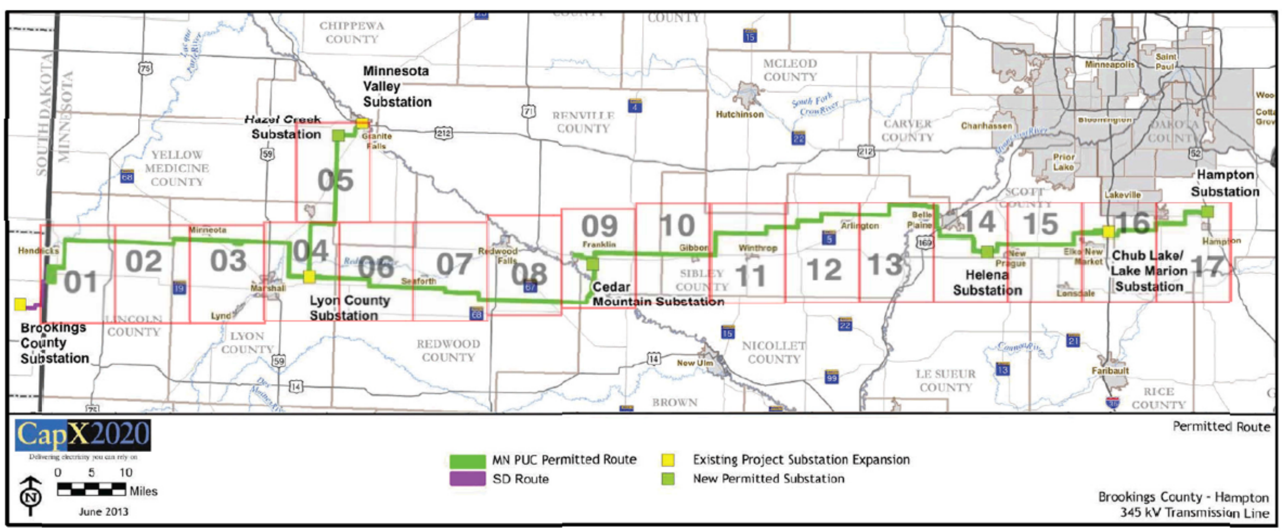
Figure B-2: Map of WMMPA Transmission Facilities in OTP LBA



Western Minnesota also owns transmission facilities as a participant in two CapX 2020 projects. Both the CapX Brookings County and Fargo projects involve multiple utility owners of these 345 kV transmission lines, and each is structured legally as tenants-in-common, with discrete ownership shares. Substations are owned individually by a single participant, based on generally on proximity.

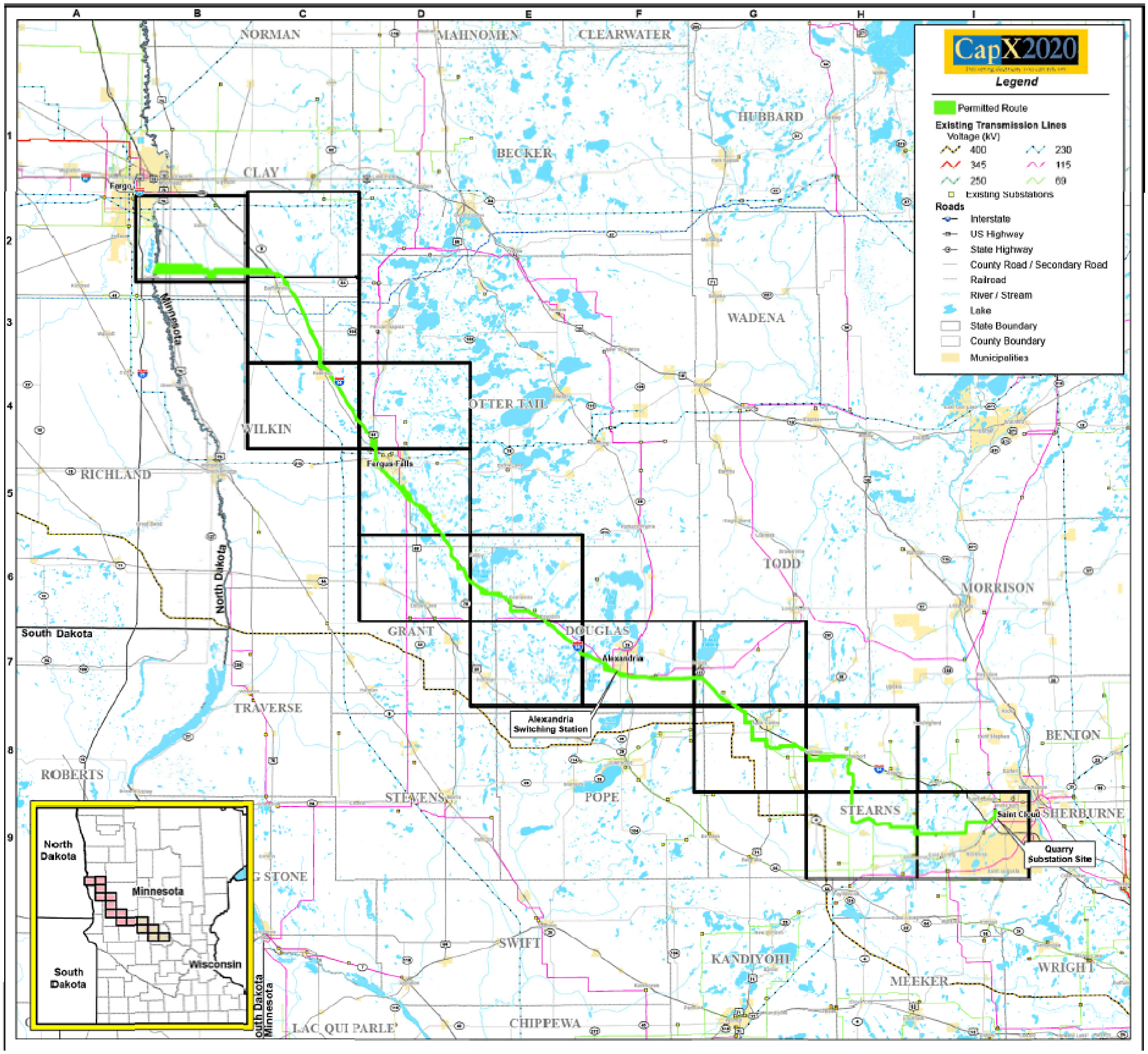
CapX Brookings County – The Brookings County 345 kV project is comprised of various segments of 345kV transmission lines between numerous 345 kV substations, including: Brookings County to Lyon County (about 58 miles), Lyon County to Hazel Creek (about 25 miles), Hazel Creek to Minnesota Valley (about 5 miles), Lyon County to Cedar Mountain (about 50 miles), Cedar Mountain to Helena (about 72 miles), Cedar Mountain to the 115kV Franklin line (about 4 miles), Helena to Chub Lake (about 20 miles), and Chub Lake to Hampton (about 18 miles). The final segment of the project was energized in the spring of 2015. Western Minnesota is one of 5 utilities that own the lines as tenants in common. Western Minnesota's owner ownership percentage is approximately 6%. See Figure B-3 for a map of these facilities.

Figure B-3: Map of WMMPA Transmission Facilities – CapX Brookings County



CapX Fargo – The Fargo 345 kV project is likewise comprised of various segments of 345kV transmission lines between numerous 345 kV substations, including: Monticello to Quarry (about 28 miles), Quarry to Alexandria (about 78 miles), and Alexandria to Bison (about 134 miles). The final segment of this project was energized in the spring of 2015. Western Minnesota is one of 5 utilities that own the lines as tenants in common. Western Minnesota's owner ownership percentage is approximately 8%. In addition, Western Minnesota wholly owns the Alexandria Substation, which is part of the Fargo project. See Figure B-4 below for a map of these facilities.

Figure B-4: Map of WMMPA Transmission Facilities – CapX Fargo



Purchases and Sales for Resale with Other Utilities

Minnesota Rule Part 7610.0600 item D requires a listing of the purchases and sales for resale the utility had with other utilities, including the names of the other utilities and megawatt hours purchased or sold for resale. Table B-4 lists the MRES purchases from other utilities in 2015:

Table B-4:
MRES Purchases from Other Utilities (2015)

Utility	Description	MWh
MISO	Midwest Independent System Operator - Energy	772,080
MISO	Midwest Independent System Operator - Regulation	36,400
BHPI	Black Hills Power, Inc.	905
CRGL	Cargill Power Markets, LLC	12,065
WAPA	Western Area Power Administration	770
AEP	American Electric Power	219,000
WPPI	WPPI Energy - Point Beach Nuclear Plant	279,133
Avangrid Renewables	Rugby, ND Wind Farm	99,738
Odin Wind, LLC	Odin, MN Wind Farm	63,380
Marshall Wind, LLC	Marshall, MN Wind Farm	65,753
City of Pella, IA	Hancock County, IA Wind Farm	8,699
	TOTAL	**1,557,922**

Table B-5 lists the MRES sales to other utilities (other than to members) in 2015. (Sales to member cities were shown in Table B-1.)

Table B-5:
MRES Sales to Non-Member Utilities (2015)

Utility	Description	MWh
MISO	Midwest Independent System Operator	42,494
SPP	Southwest Power Pool	71,619
BHPI	Black Hills Power, Inc.	2,364
CRGL	Cargill Power Markets, LLC	10,330
WAPA	Western Area Power Administration	4,995
	TOTAL	**131,802**

Present Rate Schedule

Minnesota Rule Part 7610.0600, item E requires a copy of the utility's present rate schedules as of June 1 of the present year. The 2016 S-1 rate schedule, which applies to the current 57 S-1 members, is provided separately as Appendix C.

Form EIA-861 Filing

Minnesota Rule Part 7610.0600, item F requires a copy of report form EIA-861 that was filed with the Energy Information Administration of the United States Department of Energy. Copies of the Missouri Basin Municipal Power Agency (MBMPA) and the Western Minnesota Municipal Power Agency (WMMPA) EIA-861 filings for 2014 are included in the separate Appendix D.

(Minnesota Rule Part 7610.0600, item G applies only to rural electric cooperatives and does not apply to MRES.)

Generation and Fuel Use Information

Minnesota Rule Part 7610.0600, item H requires the reporting of "total megawatts of generation capacity, the megawatt hours generated during the last calendar year, the amount of fuel used to generate the electricity, and the average Btu content of the coal used for electric generation." This information follows, in narrative format.

1. Total Megawatts of Generation Capacity

a. Laramie River Station (LRS): Approximately 273 MW of base load capacity, plus another 8 MW of peaking capacity. The peaking capacity is available by adding fuel oil to the coal being burned, and is intended primarily for emergency conditions because of its high cost and detrimental effect on unit life. Under a schedule developed by the owners of LRS, MRES receives a total of between 280 MW and 281 MW depending on the year of operation. The current amount available for scheduling to MRES, for November 2015 through October 2016, is 281 MW.

b. Exira Station (Exira): Currently accredited at 140 MW total.

c. Watertown Power Plant (WPP): Currently accredited at approximately 58.8 MW for the Winter season and 45.9 MW for the Summer season.

d. Municipal Capacity Contracts: This accredited capacity is owned by various Member communities and is under contract to MRES. The total combined municipal capacity is accredited at 133.5 MW for the summer of 2015, and 136.7 MW for the winter of 2015-16. (The lowest rating in June, July, and August for each unit was used to calculate the summer total; the lowest rating in December, January, and February for each unit was used to calculate the winter rating.)

e. Worthington Wind Project (WWP): Four of the six wind turbines that make up this project, located just west of Worthington, Minnesota, are owned by Western Minnesota and operated by MRES. The rated output of the Western Minnesota units total 3.7 MW, all of which MRES purchases. The WWP turbines are not accredited. MRES uses this energy to reduce the amount of energy purchased from MISO to serve the city of Worthington's MRES requirements.

f. Moorhead, Minnesota Wind Turbines: MRES also receives the output of the two wind turbines installed in Moorhead, Minnesota, with a total rated output of 1.5 MW. The energy is re-sold to Moorhead under the S-1 contract, having the effect of reducing the energy requirements from other MRES resources.

g. Marshall (Minnesota) Wind Farm (MWF): Nine wind turbines located near Marshall, Minnesota, one of which is owned by Western Minnesota. MRES purchases the entire output of MWF. The rated output of the project is 18.7 MW, and it receives no accredited capacity. MRES uses this energy to reduce the amount of energy purchased from MISO to serve the city of Marshall's MRES requirements.

h. Odin (Minnesota) Wind Farm (OWF): Ten wind turbines located near Odin, Minnesota, one of which is owned by Western Minnesota. MRES purchases the entire output of OWF. The nameplate output of the project is 20.0 MW, and it currently receives 2.8 MW of accreditation from MISO. The energy is sold into the MISO market.

i. Rugby, North Dakota Wind Turbines (Rugby): MRES purchases the output of a portion of the Rugby, North Dakota, wind project owned by Iberdrola Renewables. The nameplate output of the MRES share of the project is 40.0 MW, and it currently has a corresponding MISO accreditation of 6.6 MW. The energy is sold into the MISO market.

2. Megawatt Hours Generated During the Last Calendar Year

A total of 1,346,441 MWh was generated in 2015 from the following sources:

a. Laramie River Station – coal: 1,312,283 MWh
b. Exira – natural gas: 20,744 MWh
c. Watertown Peaking Plant – diesel: 143 MWh
d. Worthington Wind Project – Wind: 13,271 MWh

3. Amount of Fuel Used to Generate Electricity in 2015

a. 1.028 million tons of coal
b. 507 barrels of fuel oil
c. 207,895 MCF of natural gas

4. Average Btu Content of the Coal Used for Electric Generation

8,609 BTU/lb in 2015

Residential Space Heating Customers

Minnesota Rule 7610.0600, item I requires data on the number of residential electric space heating customers and units the utility has, and the total megawatt hours of electricity sold to these customers (estimates may be accepted).

As reported in the 2010 Integrated Resource Plan, MRES estimates that approximately 20 percent of the residential customers in the Minnesota Member communities have electric space heating. This data has not been updated for this plan for several reasons. Space heating saturation is a difficult statistic to measure as the definition of electric space heating can vary from whole house electric base board heating and in-slab heating to a single small plug-in heating appliance. In addition, the low price of natural gas in recent years has caused electric space heating to be relatively uneconomic to install and operate. As a result, it is anticipated that any meaningful change to these figures would reflect an overall reduction in the utilization of electricity for purposes of heating.

Deliveries to Consumers and Revenues Collected

Minnesota Rule 7610.0600, item J requires a report of the utility's deliveries to ultimate consumers and revenues for the last calendar year.

These items are found on Form EIA-861, which is separately included in Appendix D.

Appendix C: 2016 S-1 Rate Schedule

MISSOURI BASIN MUNICIPAL POWER AGENCY
d/b/a MISSOURI RIVER ENERGY SERVICES
POWER SALE AGREEMENT (S-1 AGREEMENT)
SCHEDULE C
S-1 RATES

All Defined Terms used herein shall be the same as in the S-1 Agreement.

1. APPLICABILITY
   This Schedule C is applicable to electric capacity and energy for all requirements of any municipality for municipality use, redistribution, and resale over and above electric power and energy available from the U.S. Department of Energy's Western Area Power Administration (WAPA) ("Supplemental Power") and delivery of such electric capacity and energy from an Energy Acquisition Point to a municipality's Delivery Point set forth in Schedule B ("Supplemental Power Delivery").

2. AVAILABILITY
   This Schedule C is applicable to any municipality purchasing from Missouri River Energy Services (MRES) under the terms of the Power Sale Agreement (S-1 Agreement) and any other Power Sale Agreements expressly incorporating this Schedule C.

3. CHARACTER OF SERVICE
   Electric power and energy furnished under this Schedule C at one or more Energy Acquisition Point(s) as set forth in Schedule A to the S-1 Agreement shall be alternating current, sixty hertz, three phases.

4. MONTHLY RATES FOR SUPPLEMENTAL POWER AND SUPPLEMENTAL POWER DELIVERY

   SUPPLEMENTAL POWER
   For electric capacity and energy furnished hereunder as Supplemental Power pursuant to Section 2 of the S-1 Agreement, the monthly charges shall be determined as follows:

   Demand Charge for Supplemental Power:
   - Summer Season (June, July, and August):
     - $20.75 per kilowatt (kW) of Supplemental Power Demand as determined in Section 10 below.
   - Winter Season (January, February, and December):
     - $15.75 per kW of Supplemental Power Demand as determined in Section 10 below.
   - All Other Months (March, April, May, September, October, and November):
     - $9.75 per kW of Supplemental Power Demand as determined in Section 10 below.

   MISO Member Capacity Rate:
   - $0.00 per kW of Supplemental Power Demand as determined in Section 10 below for all MRES Members in the Midcontinent Independent System Operator, Inc. (MISO) footprint, except for Cavalier and Northwood, North Dakota.

   Energy Charge for Supplemental Power:
   - $0.0305 per kilowatt-hour (kWh) Supplemental Power Energy as determined in Section 10 below.

SUPPLEMENTAL POWER DELIVERY
The monthly transmission charge for Supplemental Power Delivery shall be determined as follows: $4.60 per kW of Supplemental Power Demand as determined in Section 10 below times the Integrated System (IS) Factor in Section 11 below.

RIVERWINDS PROGRAM
There shall be an additional charge of $1.50 for each 100 kWh block sold to Municipalities under the optional Riverwinds Program.

5. SUPPLEMENTAL POWER COST ADJUSTMENT
The base Variable Production and Purchased Power Cost (VC) included in the Supplemental Power Energy Charge is $0.0300 per kWh. The Six Month VC (SMVC), for the purposes of this section, is defined as the actual average VC of energy produced and purchased for its Members for the preceding six-month period. If the SMVC is greater than $0.0320, the SMVC less $0.0320 times the number of kWh for the most recent month will be added to the S-1 bill.

The VC for purposes of this adjustment shall include:

(a) The variable production costs of the generating plants owned by the Western Minnesota Municipal Power Agency (WMMPA) to meet MRES member power sales requirements, and
(b) The cost of power and energy purchased by MRES or WMMPA from other power suppliers to meet member power sales requirements.

6. MEMBER-OWNED RENEWABLE RESOURCE GENERATION
If MRES has executed a contract with the Municipality requiring MRES to purchase the output from the Municipality's renewable resource generator and to resell the output to the Municipality under this S-1 Agreement as part of the Municipality's Supplemental Power (Member Renewable Resource Agreement), the charges for that generation shall be:

(a) an additional energy charge which is the product of the number of kWh of energy purchased by MRES under the Member Renewable Resource Agreement during the current billing period and the difference between the cost of energy per kWh purchased by MRES under the Member Renewable Resource Agreement during the current billing period and the Energy Charge in Section 4 of this Schedule C.
(b) $4.60 per kW of the demand output of the renewable resource generator at the time of the Municipality's peak supplemental demand if MRES incurs a transmission charge from the Southwest Power Pool (SPP) for that generation.

7. RETAIL CUSTOMER-OWNED GENERATION

RETAIL GENERATION STANDBY RATES:

Applicability:
This rate is applicable to each Municipality which has a retail customer with internal generation from a generating unit exceeding five Megawatts (MW). In the event a Municipality has a retail customer with internal generation from a unit exceeding five MW, such generation shall be separately metered. Municipality is responsible for installing metering equipment.

Demand:
If a Municipality so chooses, it may nominate all or a portion of the qualifying retail generation for the Nominated Standby Demand Rate (as defined below). In such event, the Municipality will be charged the amount of generation nominated times the Nominated Standby Demand Rate on a monthly basis.

A Municipality may make such nomination at the time the retail generation goes on-line and may change the nomination amount once per year in years subsequent to the initial nomination. Municipality is allowed to change the nomination annually. Any changes to the nomination will be effective on December 31, and MRES must be provided at least 30 days written notice of any change; however, if a nomination change is made during an Excess Standby Demand Rate period as described below, such nomination shall not take effect until the expiration of such Excess Standby Demand Rate period.

If the generation of a retail customer's internal generating unit exceeding five MW is not in service, whether planned or unplanned (out-of-service-event), the Municipality shall pay the following demand charge to replace such customer's generation measured as of the time of the Municipality's peak supplemental demand:

> In the event the Municipality nominated internal customer generation as described above, and such nomination level exceeds the demand required as a result of the out-of-service event, there shall be no charge in addition to the Nominated Standby Demand Rate.
>
> In the event the Municipality elected not to nominate internal customer generation, or nominated an amount less than the demand required due to the out-of-service event, the Municipality shall pay the Excess Standby Demand Rate (as defined below) on demand exceeding the nominated generation (or all demand if no generation was nominated) for the month of the out-of-service event and each of the succeeding 11 months (the Excess Standby Demand Rate period).

Nominated Standby Demand Rate: $5.00 per kW per month times the amount of retail customer qualifying generation nominated by the Municipality.

Excess Standby Demand Rate: The rate shall be the supplemental power demand rate in effect under Section 4, for the month of the out-of-service event. The rate will be multiplied by the retail customer's monthly 30 minute co-incident peak to the member monthly system 30 minute peak. If there is another out-of-service event during the Excess Standby Demand Rate period, the Municipality will be charged the higher of the Excess Standby Demand Rate applicable to the initial out-of-service event or the Excess Standby Demand Rate applicable to the subsequent out-of-service event.

Each retail generation out-of-service event begins a new 12 month Excess Standby Demand Rate period, commencing the month of the out-of-service event.

Energy:
Standby Energy Rate: Energy purchased by the Municipality during an out-of-service event to replace retail customer generation meeting the applicability requirements under this section will be the higher of the supplemental energy rate under Section 4 or 125 percent of the day-ahead Locational Marginal Price on the dates of such purchases.

OTHER RETAIL GENERATION RATES:
If MRES incurs a transmission charge from SPP for generation of any retail customer (irrespective of size) of a Municipality purchasing demand and energy from MRES under the S-1 Agreement and the Municipality has not been charged the Excess Standby Demand Rate, the charges for that generation shall be:

(a) $4.60 per kW of the demand output of the retail generator at the time of the Municipality's peak supplemental demand.

8. TAX ADJUSTMENT CLAUSE
   In the event of the imposition of any tax or charge for payment in lieu of tax, by any lawful authority on the production, transmission, or sale of electric power and energy sold by MRES, the charges hereunder may be increased to pass on to the Municipality its share of such tax or payment in lieu thereof.

9. LATE PAYMENT CHARGE
   A charge of five percent may be imposed on the unpaid balance of any amount due and owing after the date when such amount is due.

10. BILLING MEASUREMENT
    The metered demand in kW shall be the highest 30-minute integrated demand (or corrected to a 30-minute basis in the event 15-minute demand registers are installed) measured during the billing period (with metering reading adjustments, if any, as provided for in Schedule A of the S-1 Agreement). The billing measurements for Supplemental Power electric service furnished hereunder shall be determined as follows:

    Supplemental Power Demand = (TD-WD) plus losses
    Supplemental Power Energy = (TE-WE) plus losses

    TD – Shall be defined as the total demand for the current billing period determined on a basis in accordance with the contract in effect between the Municipality and WAPA pursuant to which WAPA sells the Municipality electric power and energy (WAPA Contract).

    TE – Shall be defined as the total energy delivered during the billing period determined on a basis in accordance with the WAPA Contract.

    WD – Shall be defined as the amount of demand delivered to the Municipality by WAPA.

    WE – Shall be defined as the amount of energy delivered to the Municipality by WAPA.

    Losses - Losses shall be 3.2 percent for market losses plus any losses charged by third party transmission provider, if applicable.

11. IS FACTOR
    The IS Factor is equal to the percentage of the Supplemental Power provided by MRES to the Municipality from electric capacity and energy obtained at Energy Acquisition Points interconnected directly with the SPP Upper Missouri Zone (UMZ) and deemed to flow over the UMZ divided by all Supplemental Power billed to the Municipality. The IS factor shall be:
    (a) Zero percent for all municipalities purchasing Supplemental Power under the S-1 Agreement and located within the MISO Footprint, except for Northwood and Cavalier, North Dakota. The MISO Footprint shall mean the area in which the MISO is responsible for providing transmission service.
    (b) 100 percent for all other municipalities purchasing Supplemental Power under the S-1 Agreement.

12. BILLING PERIOD
    The MRES billing period shall be established to coincide with the meter reading schedules of WAPA.

Effective:	First day of the January 2016 billing period.
Approved October 8, 2015:	Board of Directors Missouri Basin Municipal Power Agency d/b/a Missouri River Energy Services
Issued by:	Thomas J. Heller, Chief Executive Officer Missouri Basin Municipal Power Agency d/b/a Missouri River Energy Services

Appendix D: EIA-861 Reports

The following are the latest available reports made to the U.S. Department of Energy, Energy Information Administration under form EIA-861, "Annual Electric Power Industry Report," for Missouri River Energy Services and for Western Minnesota Municipal Power Agency.

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2017

SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year

REPORT FOR: Missouri Basin Muni Power Agny 12710
REPORTING PERIOD: 2014

Contact Merlin Sawyer
Title: Director, Finance and CFO
Phone: (605) 338-4042 FAX: (605) 978-9385 Email: msawyer@mrenergy.com

Logged By / Date:
Logged In: ☐ Receipt Date (mm/dd/yyyy):

Supervisor Tom Heller
Title: CEO
Phone: (605) 338-4042 FAX: (605) 978-9385 Email: theller@mrenergy.com

1	Legal Name of Industry Participant	Missouri Basin Muni Power Agny **Submission Status/Date:** Submitted 04/28/2015
2	Current Address of Principal Business Office	3724 West Avera Drive Sioux Falls SD 57108 0000
3	Preparer's Legal Name Operator (if different than line 1)	
4	Current Address of Preparer's Office (if different than line 2)	
5	Respondent Type (Check One)	☐ Federal ☒ Political Subdivision ☐ Municipal Marketing Authority ☐ Cooperative ☐ Independent Power Producer or Qualifying Facility ☐ State ☐ Municipal ☐ Investor-Owned ☐ Retail Power Marketer (or Energy Service Provider) ☐ Wholesale Power Marketer ☐ Transmission Behind the Meter

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Jorge Luna-Camara Phone: (202) 586-3945 jorge.luna-camara@eia.gov **Stephen Scott** Phone: (202) 586-5140 Email: stephen.scott@eia.gov

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2017

REPORT FOR: Missouri Basin Muni Power Agny 12710

REPORT PERIOD ENDING: 2014

SCHEDULE 2, PART A. GENERAL INFORMATION

LINE NO.		
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT) [ ] NPCC [ ] SPP [ ] FRCC [ ] RFC (formerly ECAR, MAIN. MAAC) [ ] WECC [x] MRO [ ] SERC
2	Name of RTO or ISO	[ ] California ISO [ ] Southwest Power Pool [ ] Electric Reliability Council of Texas [X] Midwest ISO [ ] PJM Interconnection [ ] ISO New England [ ] New York ISO [ ] None
3	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MRO
4	Did Your Company Operate Generating Plants(s)?	[x] Yes [ ] No
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[ ] Generation from company owned plant [ ] Buying distribution on other electrical system [x] Transmission [x] Wholesale power marketing [x] Buying transmission services on other electrical system [ ] Retail power marketing [ ] Distribution using owned/leased electric wires [ ] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts) 451.0 Prior Year 479.5 Winter (Megawatts) 480.3 Prior Year 441.1
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[ ] Yes [x] No
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[ ] Yes [x] No
	If "Yes", Please Provide Additional Contact Information	Name: Title: Telephone: - - Fax: - - Email:

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2017

REPORT FOR: Missouri Basin Muni Power Agny 12710

REPORT PERIOD ENDING: 2014

SCHEDULE 2. PART B ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation		11	Sales to Ultimate Consumers	
2	Purchases from Electricity Suppliers	3,188,222	12	Sales For Resale	2,979,344
3	Exchanged Received (In)	113,165	13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)		14	Energy Consumed By Respondent Without Charge	
5	Exchanged Net	113,165			
6	Wheeled Received (In)				
7	Wheeled Delivered (Out)		15	Total Energy Losses (positive number)	322,043
8	Wheeled Net				
9	Transmission by Others Losses (Negative Number)				
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)	3,301,387	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	3,301,387

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2017

REPORT FOR: Missouri Basin Muni Power Agny 12710

REPORT PERIOD ENDING: 2014

SCHEDULE 2, PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE		(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	$	
2	Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	$	
3	Electric Operating Revenue from Sales for Resale	$	166,576.3
4	Electric Credits/Other Adjustments	$	
5	Revenue from Transmission	$	31,568.5
6	Other Electric Operating Revenue	$	125.5
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	$	198,270.3

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2017

REPORT FOR: Missouri Basin Muni Power Agny

REPORT PERIOD ENDING:

SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory

1	Total Number of Distribution Circuits	
2	Number of Distribution Circuits applying distribution automation technol	

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2017

REPORT FOR: Missouri Basin Muni Power Agny

REPORT PERIOD ENDING:

SCHEDULE 3. PART B
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1 Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A. ☐ Yes ☐ No

2 Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes,complete Part B. If No, go to complete PArt C. ☐ Yes ☐ No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

	State
3a. SAIDI value including Major Event days	
3b. SAIDI value excluding Major Event days	
4 SAIDI value including Major Event days minus loss of supply	
5a. SAIFI value including Major Event days	
5b. SAIFI value excluding Major Event days	
6. SAIFI value including Major Event days minus loss of supply	
7. Total number of customers used in these calculations	
8. At what voltage do you distinguish the distribution system from the supply system? (kV)	
9. Do you receive information about a customer outage in advance of a customer reporting it? ☐ Yes ☐ No	

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2017

REPORT FOR: Missouri Basin Muni Power Agny

REPORT PERIOD ENDING:

Part C: SAIDI and SAIFI calculated by other methods

	State
10a. SAIDI value including Major Events	
10b. SAIDI value excluding Major Events	
11a. SAIFI value including Major Events	
11b. SAIFI value excluding Major Events	
12. Total number of customers used in these calculations	
13. Do you include inactive accounts?	☐ Yes ☐ No
14. How do you define momentary interruptions	☐ Less than 1 min. ☐ Less than 5 min. ☐ Other
15. At what voltage do you distinguish the distribution system from the supply system?	kv
16. Is information about customer outages recorded automatically?	☐ Yes ☐ No

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SCHEDULE 4, PART -A . SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

State	**Balancing Authority**	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)						
Megawatthours						
Number of Customers						
Are your rates decoupled?		☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?		N automatic	N automatic	N automatic	N automatic	
		N proceeding	N proceeding	N proceeding	N proceeding	
Cents/Kwh						
State						
Revenue (thousand dollars)						
Megawatthours						
Number of Customers						
Are your rates decoupled?						
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?						
Cents/Kwh						
Total						
Revenue (thousand dollars)						
Megawatthours						
Number of Customers						

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SCHEDULE 4, PART -B . SALES TO ULTIMATE CUSTOMERS. ENERGY – ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 4, PART -C . SALES TO ULTIMATE CUSTOMERS. DELIVERY – ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 4, PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 5 MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

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SCHEDULE 6 PART A. ENERGY EFFICIENCY PROGRAMS

Schedule 6. Part A. Adjusted Gross Energy and Demand Savings – Energy Efficiency

State/Territory **Balancing Authority**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)					
2	Peak Demand Savings (MW)					
	Increment Life Cycle Savings					
3	Energy Savings (MWh)					
4	Peake Demand Savings (MW)					
	Reporting Year Incremental Costs					
5	Customer Incentives					
6	All other costs					
	Incremental Life Sycle Costs					
7	Customer Incentives					
8	All other costs					
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life					

Please provide website address to your energy efficiency program reports:

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Schedule 6. Part B. Energy and Demand Savings -- Demand Response

Reporting Year Savings

State/Territory	**Balancing Authority**	(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled					
2	Energy Savings (Mwh)					
3	Poteneital Peak Demand Savings (MW)					
4	Actual Peak Demand Savings (MW)					

Schedule 6. Part B. Program Costs -- Demand Responses (Thousand Dollars)

Reporting Yearly Costs

5	Customer Incentives	
6	All other costs	
7	If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?	

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS

Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory **Balancing Authority**

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class					

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customer are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No
3	Real TimePricing	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No
4	Variable Peak Pricing	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No
5	Critical Peak Pricing	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No
6	Critical Peak Rebate	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No

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SCHEDULE 6, PART D ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State **Balancing Authority**

	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1 Number of AMR Meters					
2 Number of AMI Meters					
3 Number of AMI Meters with home area network (HAN) gateway enabled					
4 Number of non AMR/AMI Meters					
5 Total Number of Meters (All Types), line 1+2+4					
6 Energy Served Through AMI					
7 Number of Customers able to access daily energy usage through a webportal or other electronic means					
8 Number of customers with direct load control					

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SCHEDULE 7. PART A. NET METERING

Net Metering program allow customers to sell excess power they generate back to the electrical grid to offset consumption. Provide the information about programs by Statem balancing authority, customer class, and technology for all net metering applications.

State	Balancing Authority	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
	Installed Net Metering Capacity (MW)					
Photololatic	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot be Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Wind	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot be Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Other	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot be Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Total	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot be Utility (Mwh)					

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SCHEDULE 7. PART B. DISTRIBUTED AND DISPERSED GENERATION

If your company owns and/or operates a distribution system, please report information on known distributed generation capacity on the system. Such capacity must be utility or customer-owned

NUMBER AND CAPACITY

State	Balancing Authority		
	Distributed Generators (Commercial and Industrial Grid Connected/Synchronized Generators) (a)		Dispersed Generators (Commercial and Industrial Generators Not Connected/Synchronized to the Grid) (b)
	< 1MW		< 1MW
1. Number of generators		1. Number of generators	
2. Total combined capacity (MW)		2. Total combined capacity (MW)	
3. Capacity that consists of backup-only units		3. Capacity that consists of backup-only units	
4 Capacity owned by respondent		4. Capacity owned by respondent	
5. Nature of data reported	☐ Actual ☐ Estimated	5. Nature of data reported	☐ Actual ☐ Estimated

Capacity by Technology (MW)

1. Internal combustion/reciprocating engines		1. Internal combustion/reciprocating engines	
2. Combustion turbine(s)		2. Combustion turbine(s)	
3. Steam turbine(s)		3. Steam turbine(s)	
4. Hydroelectric		4. Hydroelectric	
5. Wind turbine(s)		5. Wind turbine(s)	
6, Photovoltaic		6. Photovoltaic	
7. Storage		7. Storage	
8. Other		8. Other	
9. Total		9. Total	
10. Nature of data reported	☐ Actual ☐ Estimated	10. Nature of data reported	☐ Actual ☐ Estimated

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SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	-				

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SCHEDULE 9. COMMENTS

SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)

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EIA861 ERROR LOG

Part	State	Error No.	Error Description/Override Comment	Type	Override

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SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: **Please submit by April 30th following the close of calendar year**

Contact Merlin Sawyer
Title: Director, Finance and CFO
Phone: (605) 338-4042 FAX: (605) 978-9385 Email: msawyer@mrenergy.com

REPORT FOR: Western Minnesota Mun Pwr Agny 20421
REPORTING PERIOD: 2014

Supervisor Tom Heller
Title: CEO
Phone: (605) 338-4042 FAX: (605) 978-9385 Email: theller@mrenergy.com

Logged By / Date:
Logged In: ☐ Receipt Date (mm/dd/yyyy):

1	Legal Name of Industry Participant	Western Minnesota Mun Pwr Agny **Submission Status/Date:** Submitted 04/28/2015
2	Current Address of Principal Business Office	3724 West Avera Drive Sioux Falls SD 57109
3	Preparer's Legal Name Operator (if different than line 1)	
4	Current Address of Preparer's Office (if different than line 2)	
5	Respondent Type (Check One)	☐ Federal ☒ Political Subdivision ☐ Municipal Marketing Authority ☐ Cooperative ☐ Independent Power Producer or Qualifying Facility ☐ State ☐ Municipal ☐ Investor-Owned ☐ Retail Power Marketer (or Energy Service Provider) ☐ Wholesale Power Marketer ☐ Transmission Behind the Meter

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Jorge Luna-Camara Phone: (202) 586-3945 jorge.luna-camara@eia.gov **Stephen Scott** Phone: (202) 586-5140 Email: stephen.scott@eia.gov

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SCHEDULE 2, PART A. GENERAL INFORMATION

LINE NO.			
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT) [ ] FRCC [x] MRO	[ ] NPCC [ ] RFC (formerly ECAR, MAIN. MAAC) [ ] SERC [ ] SPP [ ] WECC
2	Name of RTO or ISO	[ ] California ISO [ ] Electric Reliability Council of Texas [ ] PJM Interconnection [ ] New York ISO	[ ] Southwest Power Pool [x] Midwest ISO [ ] ISO New England [ ] None
3	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MRO	
4	Did Your Company Operate Generating Plants(s)?	[ ] Yes	[x] No
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[x] Generation from company owned plant [x] Transmission [ ] Buying transmission services on other electrical system [ ] Distribution using owned/leased electric wires	[ ] Buying distribution on other electrical system [ ] Wholesale power marketing [ ] Retail power marketing [ ] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts) 451.0 Prior Year 479.5 Winter (Megawatts) 480.3 Prior Year 441.1	
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[ ] Yes	[x] No
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[ ] Yes	[x] No
	If "Yes", Please Provide Additional Contact Information	Name: Title: Telephone: - -	Fax: - - Email:

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SCHEDULE 2. PART B ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation	1,993,681	11	Sales to Ultimate Consumers	
2	Purchases from Electricity Suppliers		12	Sales For Resale	1,993,681
3	Exchanged Received (In)		13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)		14	Energy Consumed By Respondent Without Charge	
5	Exchanged Net				
6	Wheeled Received (In)				
7	Wheeled Delivered (Out)		15	Total Energy Losses (positive number)	
8	Wheeled Net				
9	Transmission by Others Losses (Negative Number)				
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)	1,993,681	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	1,993,681

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SCHEDULE 2, PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE		(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	$	
2	Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	$	
3	Electric Operating Revenue from Sales for Resale	$	95,972.0
4	Electric Credits/Other Adjustments	$	
5	Revenue from Transmission	$	
6	Other Electric Operating Revenue	$	72.5
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	$	96,044.5

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SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory

1	Total Number of Distribution Circuits	
2	Number of Distribution Circuits applying distribution automation technol	

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SCHEDULE 3. PART B
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1 Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A. ☐ Yes ☐ No

2 Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes,complete Part B. If No, go to complete PArt C. ☐ Yes ☐ No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

	State
3a. SAIDI value including Major Event days	
3b. SAIDI value excluding Major Event days	
4 SAIDI value including Major Event days minus loss of supply	
5a. SAIFI value including Major Event days	
5b. SAIFI value excluding Major Event days	
6. SAIFI value including Major Event days minus loss of supply	
7. Total number of customers used in these calculations	
8. At what voltage do you distinguish the distribution system from the supply system? (kV)	
9. Do you receive information about a customer outage in advance of a customer reporting it?	☐ Yes ☐ No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

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Part C: SAIDI and SAIFI calculated by other methods

	State
10a. SAIDI value including Major Events	
10b. SAIDI value excluding Major Events	
11a. SAIFI value including Major Events	
11b. SAIFI value excluding Major Events	
12. Total number of customers used in these calculations	
13. Do you include inactive accounts?	☐ Yes ☐ No
14. How do you define momentary interruptions	☐ Less than 1 min. ☐ Less than 5 min. ☐ Other
15. At what voltage do you distinguish the distribution system from the supply system?	kv
16. Is information about customer outages recorded automatically?	☐ Yes ☐ No

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SCHEDULE 4, PART -A . SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

State	**Balancing Authority**	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)						
Megawatthours						
Number of Customers						
Are your rates decoupled?		☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?		N automatic	N automatic	N automatic	N automatic	
		N proceeding	N proceeding	N proceeding	N proceeding	
Cents/Kwh						
State						
Revenue (thousand dollars)						
Megawatthours						
Number of Customers						
Are your rates decoupled?						
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?						
Cents/Kwh						

Total
Revenue (thousand dollars)

Megawatthours

Number of Customers

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SCHEDULE 4, PART -B . SALES TO ULTIMATE CUSTOMERS. ENERGY – ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 4, PART -C . SALES TO ULTIMATE CUSTOMERS. DELIVERY – ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 4, PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 5 MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

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REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

SCHEDULE 6 PART A. ENERGY EFFICIENCY PROGRAMS

Schedule 6. Part A. Adjusted Gross Energy and Demand Savings – Energy Efficiency

State/Territory **Balancing Authority**

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
Reporting Year Incremental Annual Savings					
1 Energy Savings (MWh)					
2 Peak Demand Savings (MW)					
Increment Life Cycle Savings					
3 Energy Savings (MWh)					
4 Peake Demand Savings (MW)					
Reporting Year Incremental Costs					
5 Customer Incentives					
6 All other costs					
Incremental Life Sycle Costs					
7 Customer Incentives					
8 All other costs					
Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9 Weighted Average Life					

Please provide website address to your energy efficiency program reports:

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Schedule 6. Part B. Energy and Demand Savings -- Demand Response

Reporting Year Savings

State/Territory	**Balancing Authority**	(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled					
2	Energy Savings (Mwh)					
3	Potenetial Peak Demand Savings (MW)					
4	Actual Peak Demand Savings (MW)					

Schedule 6. Part B. Program Costs -- Demand Responses (Thousand Dollars)

Reporting Yearly Costs

5	Customer Incentives	
6	All other costs	
7	If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?	

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REPORT FOR: Western Minnesota Mun Pwr Agny

REPORT PERIOD ENDING:

SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS

Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory **Balancing Authority**

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class					

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customer are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No
3	Real TimePricing	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No
4	Variable Peak Pricing	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No
5	Critical Peak Pricing	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No
6	Critical Peak Rebate	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No

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REPORT PERIOD ENDING

SCHEDULE 6, PART D ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State **Balancing Authority**

	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1 Number of AMR Meters					
2 Number of AMI Meters					
3 Number of AMI Meters with home area network (HAN) gateway enabled					
4 Number of non AMR/AMI Meters					
5 Total Number of Meters (All Types), line 1+2+4					
6 Energy Served Through AMI					
7 Number of Customers able to access daily energy usage through a webportal or other electronic means					
8 Number of customers with direct load control					

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REPORT FOR Western Minnesota Mun Pwr Agny

REPORT PERIOD ENDING

SCHEDULE 7. PART A. NET METERING

Net Metering program allow customers to sell excess power they generate back to the electrical grid to offset consumption. Provide the information about programs by Statem balancing authority, customer class, and technology for all net metering applications.

State	Balancing Authority	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
	Installed Net Metering Capacity (MW)					
Photololatic	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Wind	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Other	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Total	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					

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REPORT PERIOD ENDING

SCHEDULE 7. PART B. DISTRIBUTED AND DISPERSED GENERATION

If your company owns and/or operates a distribution system, please report information on known distributed generation capacity on the system. Such capacity must be utility or customer-owned

NUMBER AND CAPACITY

	Distributed Generators (Commercial and Industrial Grid Connected/Synchronized Generators) (a)		Dispersed Generators (Commercial and Industrial Generators Not Connected/Synchronized to the Grid) (b)
State	**Balancing Authority**		
	< 1MW		< 1MW
1. Number of generators		1. Number of generators	
2. Total combined capacity (MW)		2. Total combined capacity (MW)	
3. Capacity that consists of backup-only units		3. Capacity that consists of backup-only units	
4 Capacity owned by respondent		4. Capacity owned by respondent	
5. Nature of data reported	☐ Actual ☐ Estimated	5. Nature of data reported	☐ Actual ☐ Estimated

Capacity by Technology (MW)

1. Internal combustion/reciprocating engines		1. Internal combustion/reciprocating engines	
2. Combustion turbine(s)		2. Combustion turbine(s)	
3. Steam turbine(s)		3. Steam turbine(s)	
4. Hydroelectric		4. Hydroelectric	
5. Wind turbine(s)		5. Wind turbine(s)	
6, Photovoltaic		6. Photovoltaic	
7. Storage		7. Storage	
8. Other		8. Other	
9. Total		9. Total	
10. Nature of data reported	☐ Actual ☐ Estimated	10. Nature of data reported	☐ Actual ☐ Estimated

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REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	-				

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SCHEDULE 9. COMMENTS

SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)

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EIA861 ERROR LOG

Part	State	Error No.	Error Description/Override Comment	Type	Override

SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year

REPORT FOR: Western Minnesota Mun Pwr Agny 20421
REPORTING PERIOD: 2014

Contact Merlin Sawyer
Title: Director, Finance and CFO
Phone: (605) 338-4042 FAX: (605) 978-9385 Email: msawyer@mrenergy.com

Supervisor Tom Heller
Title: CEO
Phone: (605) 338-4042 FAX: (605) 978-9385 Email: theller@mrenergy.com

Logged By / Date:
Logged In: Receipt Date (mm/dd/yyyy):

1	Legal Name of Industry Participant	Western Minnesota Mun Pwr Agny — **Submission Status/Date:** Submitted 04/28/2015
2	Current Address of Principal Business Office	3724 West Avera Drive Sioux Falls SD 57109
3	Preparer's Legal Name Operator (if different than line 1)	
4	Current Address of Preparer's Office (if different than line 2)	
5	Respondent Type (Check One)	☐ Federal ☒ Political Subdivision ☐ Municipal Marketing Authority ☐ Cooperative ☐ Independent Power Producer or Qualifying Facility ☐ State ☐ Municipal ☐ Investor-Owned ☐ Retail Power Marketer (or Energy Service Provider) ☐ Wholesale Power Marketer ☐ Transmission Behind the Meter

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Jorge Luna-Camara Phone: (202) 586-3945 jorge.luna-camara@eia.gov **Stephen Scott** Phone: (202) 586-5140 Email: stephen.scott@eia.gov

REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

SCHEDULE 2, PART A. GENERAL INFORMATION

LINE NO.					
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT) [ ] FRCC [x] MRO	[ ] NPCC [ ] RFC (formerly ECAR, MAIN. MAAC) [ ] SERC	[ ] SPP [ ] WECC	
2	Name of RTO or ISO	[ ] California ISO [ ] Electric Reliability Council of Texas [ ] PJM Interconnection [ ] New York ISO		[ ] Southwest Power Pool [X] Midwest ISO [ ] ISO New England [ ] None	
3	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MRO			
4	Did Your Company Operate Generating Plants(s)?	[ ] Yes	[x] No		
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[x] Generation from company owned plant [x] Transmission [ ] Buying transmission services on other electrical system [ ] Distribution using owned/leased electric wires		[ ] Buying distribution on other electrical system [ ] Wholesale power marketing [ ] Retail power marketing [ ] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))	
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts)	451.0	Prior Year	479.5
		Winter (Megawatts)	480.3	Prior Year	441.1
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[ ] Yes	[x] No		
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[ ] Yes	[x] No		
	If "Yes", Please Provide Additional Contact Information	Name: Title: Telephone: - -	Fax: - -	Email:	

REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

SCHEDULE 2. PART B ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation	1,993,681	11	Sales to Ultimate Consumers	
2	Purchases from Electricity Suppliers		12	Sales For Resale	1,993,681
3	Exchanged Received (In)		13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)		14	Energy Consumed By Respondent Without Charge	
5	Exchanged Net				
6	Wheeled Received (In)				
7	Wheeled Delivered (Out)		15	Total Energy Losses (positive number)	
8	Wheeled Net				
9	Transmission by Others Losses (Negative Number)				
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)	1,993,681	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	1,993,681

REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

SCHEDULE 2, PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE		(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	$	
2	1 Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	$	
3	Electric Operating Revenue from Sales for Resale	$	95,972.0
4	Electric Credits/Other Adjustments	$	
5	Revenue from Transmission	$	
6	Other Electric Operating Revenue	$	72.5
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	$	96,044.5

REPORT FOR: Western Minnesota Mun Pwr Agny

REPORT PERIOD ENDING:

SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory

1	Total Number of Distribution Circuits	
2	Number of Distribution Circuits applying distribution automation technol	

REPORT FOR: Western Minnesota Mun Pwr Agny

REPORT PERIOD ENDING:

SCHEDULE 3. PART B
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1 Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A. ☐ Yes ☐ No

2 Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes,complete Part B. If No, go to complete PArt C. ☐ Yes ☐ No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

		State
3a.	SAIDI value including Major Event days	
3b.	SAIDI value excluding Major Event days	
4	SAIDI value including Major Event days minus loss of supply	
5a.	SAIFI value including Major Event days	
5b.	SAIFI value excluding Major Event days	
6.	SAIFI value including Major Event days minus loss of supply	
7.	Total number of customers used in these calculations	
8.	At what voltage do you distinguish the distribution system from the supply system? (kV)	
9.	Do you receive information about a customer outage in advance of a customer reporting it?	☐ Yes ☐ No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

REPORT FOR: Western Minnesota Mun Pwr Agny

REPORT PERIOD ENDING:

Part C: SAIDI and SAIFI calculated by other methods

	State
10a. SAIDI value including Major Events	
10b. SAIDI value excluding Major Events	
11a. SAIFI value including Major Events	
11b. SAIFI value excluding Major Events	
12. Total number of customers used in these calculations	
13. Do you include inactive accounts?	☐ Yes ☐ No
14. How do you define momentary interruptions	☐ Less than 1 min. ☐ Less than 5 min. ☐ Other
15. At what voltage do you distinguish the distribution system from the supply system?	kv
16. Is information about customer outages recorded automatically?	☐ Yes ☐ No

REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

SCHEDULE 4, PART -A . SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

State	**Balancing Authority**	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)						
Megawatthours						
Number of Customers						
Are your rates decoupled?		☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?		N automatic	N automatic	N automatic	N automatic	
		N proceeding	N proceeding	N proceeding	N proceeding	
Cents/Kwh						
State						
Revenue (thousand dollars)						
Megawatthours						
Number of Customers						
Are your rates decoupled?						
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?						
Cents/Kwh						

Total	
Revenue (thousand dollars)	
Megawatthours	
Number of Customers	

REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

SCHEDULE 4, PART -B . SALES TO ULTIMATE CUSTOMERS. ENERGY -- ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

SCHEDULE 4, PART -C . SALES TO ULTIMATE CUSTOMERS. DELIVERY -- ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total

Revenue (thousand dollars)

Megawatthours

Number of Customers

REPORT FOR: Western Minnesota Mun Pwr Agny 20421

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REPORT PERIOD ENDING: 2014

SCHEDULE 4, PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total	
Revenue (thousand dollars)	
Megawatthours	
Number of Customers	

REPORT FOR: Western Minnesota Mun Pwr Agny Utility Id 20421

REPORTING PERIOD: 2014

SCHEDULE 5 MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

SCHEDULE 6 PART A. ENERGY EFFICIENCY PROGRAMS
Schedule 6. Part A. Adjusted Gross Energy and Demand Savings -- Energy Efficiency

State/Territory **Balancing Authority**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)					
2	Peak Demand Savings (MW)					
	Increment Life Cycle Savings					
3	Energy Savings (MWh)					
4	Peake Demand Savings (MW)					
	Reporting Year Incremental Costs					
5	Customer Incentives					
6	All other costs					
	Incremental Life Sycle Costs					
7	Customer Incentives					
8	All other costs					
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life					

Please provide website address to your energy efficiency program reports:

REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

Schedule 6. Part B. Energy and Demand Savings -- Demand Response

Reporting Year Savings

State/Territory	Balancing Authority	(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled					
2	Energy Savings (Mwh)					
3	Potenetial Peak Demand Savings (MW)					
4	Actual Peak Demand Savings (MW)					

Schedule 6. Part B. Program Costs -- Demand Responses (Thousand Dollars)

Reporting Yearly Costs

5	Customer Incentives	
6	All other costs	

7 If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?

REPORT FOR: Western Minnesota Mun Pwr Agny

REPORT PERIOD ENDING:

SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS
Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory **Balancing Authority**

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class					

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customer are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	Yes x No	Yes x No	Yes x No	Yes x No
3	Real TimePricing	Yes x No	Yes x No	Yes x No	Yes x No
4	Variable Peak Pricing	Yes x No	Yes x No	Yes x No	Yes x No
5	Critical Peak Pricing	Yes x No	Yes x No	Yes x No	Yes x No
6	Critical Peak Rebate	Yes x No	Yes x No	Yes x No	Yes x No

REPORT FOR Western Minnesota Mun Pwr Agny

REPORT PERIOD ENDING

SCHEDULE 6, PART D ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State **Balancing Authority**

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters					
2	Number of AMI Meters					
3	Number of AMI Meters with home area network (HAN) gateway enabled					
4	Number of non AMR/AMI Meters					
5	Total Number of Meters (All Types), line 1+2+4					
6	Energy Served Through AMI					
7	Number of Customers able to access daily energy usage through a webportal or other electronic means					
8	Number of customers with direct load control					

REPORT FOR Western Minnesota Mun Pwr Agny

REPORT PERIOD ENDING

SCHEDULE 7. PART A. NET METERING

Net Metering program allow customers to sell excess power they generate back to the electrical grid to offset consumption. Provide the information about programs by Statem balancing authority, customer class, and technology for all net metering applications.

State	**Balancing Authority**	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
	Installed Net Metering Capacity (MW)					
Photololatic	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Wind	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Other	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Total	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					

REPORT FOR Western Minnesota Mun Pwr Agny

REPORT PERIOD ENDING

SCHEDULE 7. PART B. DISTRIBUTED AND DISPERSED GENERATION

If your company owns and/or operates a distribution system, please report information on known distributed generation capacity on the system. Such capacity must be utility or customer-owned

NUMBER AND CAPACITY

Distributed Generators (Commercial and Industrial Grid Connected/Synchronized Generators) (a)		Dispersed Generators (Commercial and Industrial Generators Not Connected/Synchronized to the Grid) (b)	
State	**Balancing Authority**		
	< 1MW		< 1MW
1. Number of generators		1. Number of generators	
2. Total combined capacity (MW)		2. Total combined capacity (MW)	
3. Capacity that consists of backup-only units		3. Capacity that consists of backup-only units	
4 Capacity owned by respondent		4. Capacity owned by respondent	
5. Nature of data reported	☐ Actual ☐ Estimated	5. Nature of data reported	☐ Actual ☐ Estimated

Capacity by Technology (MW)

1. Internal combustion/reciprocating engines		1. Internal combustion/reciprocating engines	
2. Combustion turbine(s)		2. Combustion turbine(s)	
3. Steam turbine(s)		3. Steam turbine(s)	
4. Hydroelectric		4. Hydroelectric	
5. Wind turbine(s)		5. Wind turbine(s)	
6, Photovoltaic		6. Photovoltaic	
7. Storage		7. Storage	
8. Other		8. Other	
9. Total		9. Total	
10. Nature of data reported	☐ Actual ☐ Estimated	10. Nature of data reported	☐ Actual ☐ Estimated

REPORT FOR: Western Minnesota Mun Pwr Agny 20421

REPORT PERIOD ENDING: 2014

SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	-				

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SCHEDULE 9. COMMENTS

SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)

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EIA861 ERROR LOG

Part	State	Error No.	Error Description/Override Comment	Type	Override