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Minnesota Municipal Power Agency

APPLICATION FOR INTEGRATED RESOURCE PLAN APPROVAL 2019 - 2033

SUBMITTED TO THE MINNESOTA PUBLIC UTILITIES COMMISSION

July 30, 2018

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Section 1. Executive Summary

This section is intended to provide a brief overview of the Minnesota Municipal Power Agency's (MMPA) Integrated Resource Plan (IRP).

Electric Utility Industry in Transition

The electric utility industry is in a period of transition. The industry is experiencing a shift in the following areas:

- Decreasing cost of generation resources such as battery storage systems, solar, and wind;
- Advancements in hardware and software technologies; and
- Stagnant load growth;

This transitional environment creates uncertainty in planning. Section 9 discusses MMPA's Planning Approach.

Begin Serving Elk River Municipal Utilities in October 2018

Elk River Municipal Utilities (ERMU) became the twelfth member of MMPA in June 2013. ERMU serves 11,400 metered electric customers and has a peak demand of approximately 65 MW. MMPA's electrical power load is projected to increase by approximately 20 percent with the addition of ERMU. The Agency will begin providing wholesale power to ERMU on October 1, 2018, under a power sales agreement that runs through 2050.

MMPA Strives to Meet Its Conservation Goal

The Agency strives to meet its conservation goal for reducing electricity use of its members' customers. MMPA focuses on conservation strategies with the lowest cost per kWh of electricity saved. MMPA's conservation programs are discussed in Section 6 under Energy Conservation and Demand Side Management.

Energy and Demand Growth Projected to Be Lower Than Historical Levels

MMPA's energy and demand growth are projected to be lower than historical levels. The 2004-2017 historical compounded annual energy growth rate was 1.8%, whereas the projected annual energy growth rate for 2019-2033 is 0.8%. The 2004-2017 historical growth rate for non-coincident peak (NCP) demand was 1.4%, whereas the projected growth rate for 2019-2033 is 0.8%. The slower growth rates are attributed to projected population slowdowns and improved conservation efforts, among other factors.

The table below shows MMPA's projected annual growth for energy, NCP demand, and coincident peak (CP) demand with the Midcontinent Independent System Operator (MISO).

	2019-2033
Energy Growth	0.8%
NCP Growth	0.8%
CP Growth	0.8%

Sections 4 and 5 and Appendix A provide further details on the projections and projection methodology.

No Capacity Needed Until Planning Year 2030

The Agency does not need capacity until planning year 2030. Since capacity is not needed for the next eleven years, at the direction of the Department of Commerce staff, an evaluation of resource alternatives was not conducted for this IRP. However, MMPA will continue to evaluate the energy market to understand options to meet its future electric supply needs. Capacity requirements are discussed in Section 8. The short-range action plan is discussed in Section 10 and the long-range plan is presented in Section 11.

MMPA Is Positioned to Meet the RES

MMPA is positioned to meet the Renewable Energy Standard (RES). Since the last IRP the Agency has added the following renewable resources to its portfolio:

- 78 MW Black Oak Getty Wind Farm (2016),
- 7.1 MW AC utility-level solar facility, Buffalo Solar (2017)

In addition, MMPA signed a power purchase agreement (PPA) for 170 MW of wind that is anticipated to be commercially available in December 2019. Section 12 addresses meeting the RES as well as the rate impact of complying with the RES.

MMPA's Plan Is in The Public Interest

MMPA's IRP is in the public interest. The Agency's plan allows MMPA to maintain flexibility during this electric industry transition period, reducing risks to its customers while keeping rates as low as practicable. MMPA's plan also minimizes negative environmental impacts through its emphasis on conservation and renewable energy. Section 13 further describes how MMPA's plan is in the public interest.

Section 2. About MMPA

This section provides overview information about the Minnesota Municipal Power Agency.

MMPA Is a Municipal Power Agency

MMPA is a municipal power agency formed in 1992 under Chapter 453 of Minnesota Statutes. The Agency is a political subdivision of the state of Minnesota.

MMPA provides electricity to its municipal utility members and they in turn sell that electricity to residential and business customers in their community. MMPA began supplying power to its members in 1995.

MMPA is governed by a board of directors.

Has 12 Member Cities

MMPA is composed of the following twelve Minnesota communities:

- Anoka
- Arlington
- Brownton
- Buffalo
- Chaska
- East Grand Forks
- Elk River
- Le Sueur
- North St. Paul
- Olivia
- Shakopee
- Winthrop

MMPA's member municipal utilities have approximately 74,000 retail customers in Minnesota with a combined population of approximately 160,000.

MMPA Is Mission-Driven

MMPA's mission is to provide reliable, competitively-priced power to its members and to create value for both the Agency and its members. In addition, MMPA is committed to supporting the communities it serves and does so by offering an energy education program, developing local power generation in member communities, providing conservation and renewable energy programs to members' customers, and converting waste from its member communities into electricity at the Hometown BioEnergy facility.

MISO Market Participant	MMPA is a market participant with MISO, a Federal Energy Regulatory Commission (FERC) regulated regional transmission organization that provides grid management services and open access to transmission facilities for the midcontinent market. MMPA is a registered generation owner and load serving entity and is responsible for submitting demand bids and generation resource offers on behalf of its members. MMPA participates in MISO zone 1.
Projected to Sell 1,925,452 MWh in 2019	MMPA is projected to sell 1,925,452 MWh of energy in 2019. In 2017, MMPA sold 1,515,800 MWh of energy. The increase in energy sales is largely from the addition of Elk River as a member community. MMPA will begin serving Elk River in October 2018.
2019 Projected Peak Load of 440 MW	MMPA projects a peak load of 440 MW in 2019. MMPA's peak load during the summer of 2017 was 344 MW on July 17, 2017. This load includes adjustments for transmission system losses, the MISO planning reserve margin, Western Area Power Administration (WAPA) allocations, and CIP savings.
First Owned Plant Completed In 2007	Faribault Energy Park (FEP), the first power plant to be owned by the Agency, was completed in 2007. The plant was built in two phases. The 159 MW simple cycle phase became operational in April 2005. The combined cycle phase, which increased both the capacity and fuel efficiency of the plant, became operational in the summer of 2007. MMPA's ownership of FEP marked a transition from a resource portfolio based solely on contracts to one that also includes Agency-owned assets. FEP is described in more detail in Section 7.
First Owned Wind Farm Completed in 2011	Oak Glen Wind Farm (OGWF) is MMPA's first owned wind farm. It is 44 MW and located near Blooming Prairie, Minnesota. It was awarded a U.S. Department of Energy "2012 Public Power Wind Award" for leadership, innovation, project creativity, and benefits to customers. OGWF's innovative ownership and financial structure also qualified the wind project to receive a $25.4 million federal grant. OGWF is described in more detail in Section 7.

Became a MISO Transmission Owner in 2013

MMPA became a transmission owning member of MISO in 2013. The Agency is the transmission owner of facilities in Chaska and Anoka.

Committed to Renewable Energy

MPPA is committed to economic renewable energy generation. In 2025, MMPA anticipates that 53% of its wholesale sales will come from renewable resources. MMPA's renewable energy sources include wind, solar, and bioenergy.

Avant Energy Manages MMPA

Minnesota Municipal Power Agency is governed by a board of directors and Avant Energy provides management services to the Agency under long-term contracts. Avant's services to MMPA include:

- Day-to-day management of operations including electricity purchasing and selling;
- Overall long-term strategic planning and management; and
- Accounting and financing.

Section 3. Business Environment

This section discusses the business environment in which MMPA operates. MMPA's IRP recognizes electricity market uncertainties that influence planning decisions.

Energy Industry in Transition

The energy industry is going through a period of transition that includes:

- Decreasing cost of generation resources such as battery storage systems, solar, and wind generation that allow these generation technologies to better compete with traditional fossil fuel-fired generation;
- Advances in hardware technology such as smart meters, as well as software technology such as energy management systems, that utilize artificial intelligence allowing customer access to real-time energy consumption information and providing better decision-making tools for utilities and their customers;
- Evolution of customer preferences where more utility customers than ever before express increased interest in their utilities procuring energy from cleaner sources of energy; and
- Scaling back of federal environmental regulations on one hand and ramping up of corporate commitment to solving environmental issues on the other.

The aforementioned transition in the energy markets and the uncertainties of the future trajectory of delivering cost effective, reliable power with small or no environmental impact contribute to a challenging planning environment.

Low Natural Gas Prices

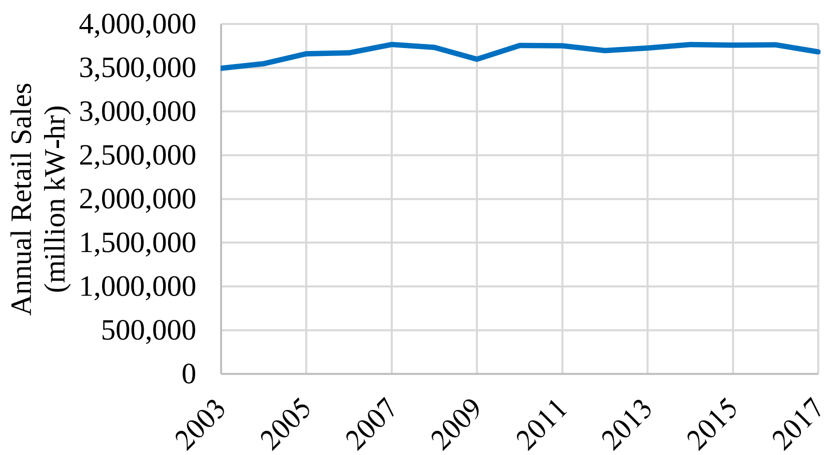
Natural gas prices are low. The shale revolution continues to put downward pressure on near to medium term gas prices. The U.S. became the largest producer of petroleum and natural gas in the world in 2012. The U.S. now produces nearly all the natural gas it consumes. Some studies project the share of shale in U.S. natural gas production is projected to rise to 45% by 2035.

Despite the robust near-term supply of natural gas, long term prices are less certain because of factors such as coal to gas switching, increased consumption from industrial and commercial production, possible environmental regulations, and increase in LNG and oil exports.

U.S. Retail Electric Sales Stagnant

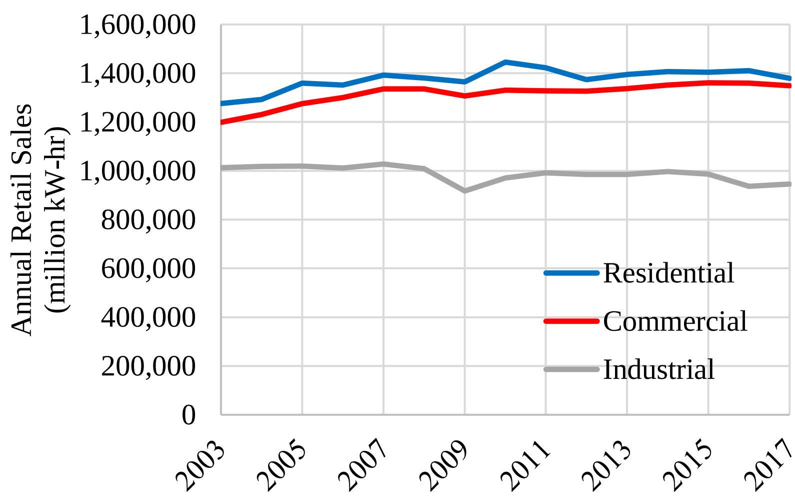
Stagnant growth of electric sales presents planning challenges for many utilities. Recent Energy Information Administration (EIA) data show that since 2003, overall retail electricity sales have risen by less than 5.5%. However, between 2007 and 2017, there was a decrease, albeit small, in overall retail electricity sales. EIA reported that between 2003 and 2017, slight residential and commercial user growth was offset by a decline in industrial users' sales. Below are two graphs that show this phenomenon.

Annual U.S. Retail Sales of Electricity



Source: U.S. Energy Information Administration

Annual U.S. Retail Sales of Electricity by Sector



Source: U.S. Energy Information Administration

EPA Emissions Standards Uncertain

Possible changes to U.S. Environmental Protection Agency (EPA) emissions standards increase planning uncertainties.

The EPA's Mercury and Air Toxics Standards (MATS) Final Rule, issued in April 2013, established emission limits for mercury, particulate matter, sulfur dioxide, acid gases, and certain individual metals for new power plants. The MATS Rule was expected to particularly affect the cost of future coal and oil-fired power plants if it fully went into effect. After reviews by courts, the D.C. circuit court suspended the case indefinitely.

In 2015, the EPA also reviewed the research linking smog exposure to adverse health effects such as asthma. Subsequently, the EPA updated the ozone rules with stricter limits to tighten standards on ozone from 75 parts per billion (ppb) to 70 ppb. In a court filing in April 2017, the federal government said the EPA officials appointed by the new administration were reviewing the 2015 rule to determine whether the EPA should reconsider some or all of the rule.

In addition, the federal government is reviewing the Clean Power Plan, which aims to cut emissions from existing power plants by 32% by 2030, and the Waters of the United States (WOTUS) rule. These emissions standards and rules could be scaled back or eliminated.

In March 2017, in a broad executive order on energy, the Interagency Working Group on the Social Cost of Greenhouse Gases was disbanded. This order withdrew the group's technical documents that form the scientific and economic basis for calculating the social cost of carbon and provide federal agencies a key tool to measure the benefits of cutting greenhouse gas emissions. While the absence of guidance from the federal government on the cost of carbon and other emissions could lead to confusion in certain types of planning scenarios, the Minnesota Public Utilities Commission has established emission costs. The costs are in its order *Updating Environmental Cost Values* issued on January 3, 2018 and in its order *Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs* issued on June 11, 2018.

Initiatives to Decrease Carbon Emissions

While the federal government has indicated a desire to the scale back or eliminate environmental regulations, individual states and some cities are taking initiatives and setting goals and rules to first cap and then decrease carbon emissions from certain sectors of their economies. In Minnesota, the legislature has a state CO_2 reduction goal of 30% by 2025 and 80% by 2050 (Minn. Stat. § 216H.02). Some of the largest cities in the U.S, including New York, Chicago, Atlanta and more than 30 others have also set ambitious emissions reductions goals.

Generation Interconnection Risks

In January 2017, the Federal Energy Regulatory Commission (FERC) conditionally approved Queue Reform 4.5 which revises the MISO generation interconnection process. Queue Reform 4.5 aims to improve the timeliness and efficiency of the interconnection process. MISO continues to incorporate Queue Reform 4.5 into the active interconnection study cycles and its Business Practices Manuals.

Timing and cost risks from the generation interconnection process persist during implementation of queue reform and may remain into the near future. MISO launches two cycles of new interconnection study groups each year for different regions. Many of the active interconnection study groups are seeing delays in the cycle process schedule. It is unknown when or if the queue reform will improve the timeliness of the interconnection process. This creates planning challenges for interconnection timing. A provisional interconnection alternative exists, but this option could create operational and transmission upgrade cost risks.

MISO Market Enhancements Continue

MISO is the entity that manages the reliable and cost-effective delivery of electricity and conducts transmission planning activities in 15 states, including Minnesota, and the Canadian province of Manitoba. MISO commenced its market operations for energy and financial transmission markets in 2005, followed by ancillary services markets in 2009, and capacity markets in 2010. Since its inception, MISO has continued to introduce or propose market enhancements and rule changes.

In 2011, MISO introduced the concept of a dispatchable intermittent resource (DIR) to address the uncertainties associated with the intermittency of wind resources. At that time, MISO had less than 10,000 MW of registered wind generation. MISO now hosts over 17,500 MW of registered wind. Over 12,500 MW of this wind is in Iowa, Minnesota, and North Dakota and MISO has managed the concentrated wind resources, locational prices, and reliability effectively.

MISO is now in the process of incorporating energy storage into its markets and complying with FERC orders 841 and 845. On April 3, 2017, MISO made a compliance filing with FERC where it revised Module A of its Tariff to add a new term called Stored Energy

Product Type 2 that would participate in energy, capacity, and ancillary service markets through the storage and discharge of electrical energy in response to set point instructions.

While the above market enhancements seem to address some of the immediate concerns of market participants, other enhancements have not had the desired effect. For instance, in 2013, MISO administered its first annual capacity auction. The system wide clearing price of $1.05 per megawatt-day for the 2013-2014 planning year reflected ample supply of generation and demand response resources in MISO and the robustness of the transmission system. The system-wide clearing price for the 2018-2019 planning year was $10.00 per megawatt-day for all zones except zone 1, which cleared at $1.00 per megawatt-day. Both clearing prices from the most recent MISO auction are low and suggest the abundance of capacity in the near term. However, the absence of long-term capacity markets and price signals for the cost of long-term capacity create planning challenges and discourage long-term investment.

The Independent Market Monitor (IMM) that monitors market activity in MISO reported in its *2016 State of the Market Report for the MISO Electricity Markets*:

> “Capacity market design issues described in this report have contributed to understated price signals, which will become an increasing concern as the capacity surplus falls due to retirements and units exporting capacity to PJM. “

Economic Uncertainty Necessitates Planning Flexibility

In the context of long-term planning, uncertainty exists because of high budget deficits, the unknown future of entitlement programs, the rising cost of living, the challenges addressing climate change, and deregulation. Increased economic uncertainty therefore necessitates the need for flexibility in energy supply planning.

Section 4. Projected Energy Requirements – 2019 to 2033

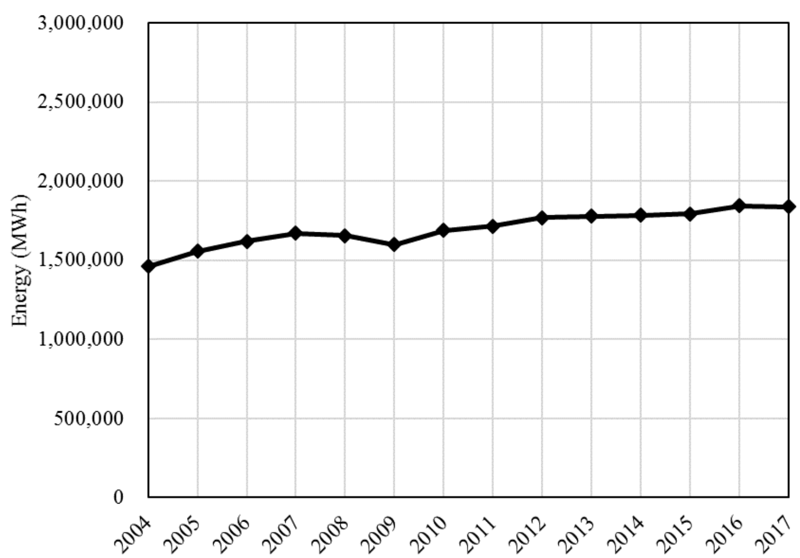
This section discusses MMPA's historical and future energy requirements.

Historical 1.8% Energy Growth Rate

Over the period 2004 to 2017, MMPA member energy requirements grew at a compound annual growth rate of approximately 1.8% for all twelve MMPA members.

The following graph shows historical MMPA member energy requirements for the years 2004 to 2017, the time period for which data is available for all twelve member cities. MMPA only served a portion of Shakopee's load until 2009. Therefore, the data has been adjusted to include all of Shakopee's load. MMPA has not historically served Elk River, but the data has been adjusted to include this load.

Minnesota Municipal Power Agency
Historical Member Energy Requirements (MWh)



MMPA Will Begin Serving Elk River in October 2018

MMPA will start providing electric service to Elk River in October 2018. The significant step up in projected energy in 2018 and 2019 is attributable to this load addition.

Linear Regression Model Used to Project Energy

A linear regression model was used to project energy usage for this IRP. The variables in the model are:

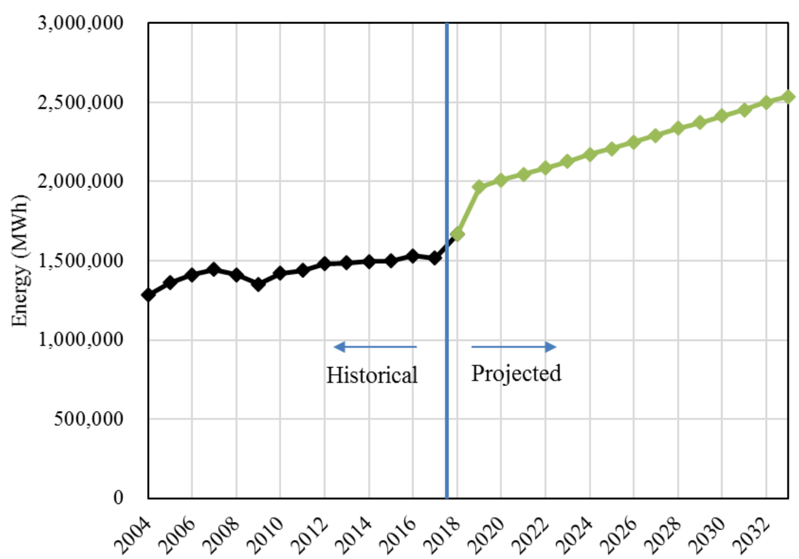
- Weather (heating degree days and cooling degree days)
- Population
- Income per capita

Details on the inputs and assumptions of the methodology can be found in Appendix A.

Projected 1.8% Energy Growth Rate without New Conservation

MMPA's projected energy growth rate without new conservation is 1.8% for the 2019-2033 projection period. The following graph shows historical and projected MMPA base energy requirements, without conservation adjustments, for the period 2004 to 2033.

Minnesota Municipal Power Agency
Historical & Projected Base Member
Energy Requirements (MWh) Without Conservation



New Conservation Assumed to Reduce Annual Energy Growth Rate By 1.0%

New conservation measures are assumed to reduce the Agency's annual energy growth rate by approximately 1.0%. For further clarification, the base case of 1.3% conservation does not translate into a 1.3% reduction in the energy growth rate because the requirements for CIP savings calculations are based upon a lagging 3-year average of MMPA's energy consumption. MMPA's current level of energy conservation is built into the historical energy usage data that is an input into the linear regression model. Section 6 discusses in detail MMPA's current and future conservation efforts.

Lower CIP Savings Would Increase Energy Requirements

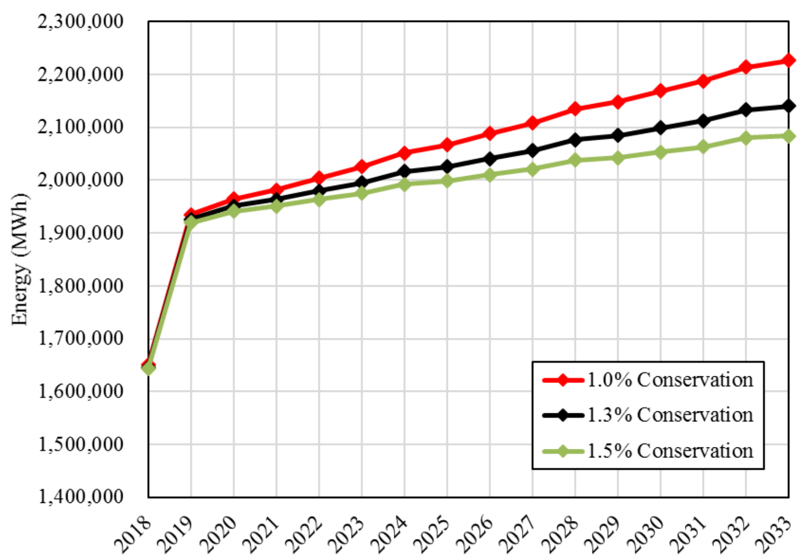
MMPA continues its successful conservation improvement program and strives to meet its CIP goals in the future. However, planning processes need to take into consideration the uncertainties associated with longer-term effectiveness of CIP programs and the possibility of diminishing returns.

This IRP contemplates three conservation rate cases for planning purposes:

- 1.0% Low Case
- 1.3% Base Case
- 1.5% High Case

Lower CIP savings in the future would increase energy requirements. The following chart shows MMPA's energy requirements for the three CIP savings cases:

Minnesota Municipal Power Agency
Projected Conservation-Adjusted Member Energy (MWh)



MMPA's CIP efforts and corresponding results are discussed in Section 6.

Lower Population Growth Rate Would Lower Electric Load Growth

Slower population growth correlates with slower load growth in the energy projections. Historical and projected population compounded annual growth rates (CAGR) for MMPA member cities are shown in the table below. Projections are based on Woods and Poole long term growth rates. Population growth rates are projected to be lower than historical population growth rates for all MMPA members.

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Additional Members Would Increase Energy Requirements	MMPA's projected energy requirements would increase if the Agency were to take on additional members. This IRP assumes that the 12-member Agency does not take on any additional members during the projection period.
Large Retail Load Additions Would Increase Energy Requirements	MMPA's projected energy requirements would increase if its members were to take on new large retail loads. This IRP does not include any new large retail loads during the projection period.
Less Supply from WAPA Would Increase Energy Requirements	Two of MMPA's members currently receive allocations of energy (approximately 95,000 MWh per year) from the Western Area Power Administration (WAPA). Both members have long-term contracts for these energy allocations. However, WAPA could reduce the amount of energy and power available to its customers in the future. This would represent a policy change from the past. If WAPA decreases the energy available to its customers, MMPA's energy requirements would increase, because the Agency provides all of the energy to these two members that is not supplied by WAPA. This IRP assumes that WAPA allocations remain at the current contract amounts throughout the projection period.
More Electric Use for Transportation Could Increase Energy Requirements	In previous IRPs, we discussed electricity used as a fuel for transportation. This concept continues to hold the potential to reduce oil reliance and reduce carbon emissions from transportation. Increased market penetration of electric and hybrid vehicles in MMPA member communities could increase energy requirements.

A recent paper published by the California Energy Commission[1] analyzes the plug-in electric vehicle charging infrastructure needed to achieve California's goal of 1.5 million zero-emission vehicles (approximately 5% of vehicles) by 2025. The report estimates that in California, electric vehicles could add more than 1 GW of peak demand by 2025. Even though California has more than five times the number of vehicles on the road compared to Minnesota[2], the paper still demonstrates the significant increase in energy requirements that could occur once electric vehicles penetrate a market.

MMPA recognizes the potential increase in energy requirements over the long term from electric and hybrid vehicles. However, this IRP assumes no increase in MMPA's electric load from electric vehicles, since in Minnesota and MMPA communities, this technology currently has a low penetration and its future penetration is unknown.

MMPA Energy Projections

The table below shows MMPA's base energy projections as well as energy requirements with and without new conservation.

Year	Base Energy	Plus Olivia WAPA Adjustment	Plus East Grand Forks WAPA Adjustment	Energy Requirements without New Conservation	Plus 1.3% Conservation	Energy Requirements with New Conservation
2019	2,060,055	(22,307)	(73,051)	1,964,697	(39,245)	1,925,452
2020	2,105,762	(22,381)	(73,304)	2,010,077	(59,553)	1,950,524
2021	2,140,052	(22,307)	(73,051)	2,044,694	(81,606)	1,963,088
2022	2,180,669	(22,307)	(73,051)	2,085,311	(105,533)	1,979,777
2023	2,221,401	(22,307)	(73,051)	2,126,043	(130,836)	1,995,207
2024	2,268,293	(22,381)	(73,304)	2,172,608	(156,374)	2,016,234
2025	2,303,249	(22,307)	(73,051)	2,207,891	(182,106)	2,025,785
2026	2,344,346	(22,307)	(73,051)	2,248,988	(208,067)	2,040,921
2027	2,385,222	(22,307)	(73,051)	2,289,864	(234,229)	2,055,635
2028	2,432,844	(22,381)	(73,304)	2,337,159	(260,588)	2,076,571
2029	2,467,272	(22,307)	(73,051)	2,371,914	(287,118)	2,084,796
2030	2,508,287	(22,307)	(73,051)	2,412,929	(313,869)	2,099,060
2031	2,548,832	(22,307)	(73,051)	2,453,474	(340,809)	2,112,665
2032	2,596,684	(22,381)	(73,304)	2,500,999	(367,937)	2,133,062
2033	2,630,808	(22,307)	(73,051)	2,535,450	(395,222)	2,140,227
Growth Rate (2019-2033)				**1.8%**		**0.8%**

[1] California Energy Commission, *California Plug-In Electric Vehicle Infrastructure Projections 2017-2025*, March 2018, CEC-600-2018-001.
[2] U.S. Department of Transportation Federal Highway Administration, *State Motor Vehicle Registrations – 2016*, November 2017, https://www.fhwa.dot.gov/policyinformation/statistics/2016/mv1.cfm.

Section 5. Projected Demand Requirements – 2019 to 2033

This section discusses MMPA's historical and future demand requirements. This IRP examines both MMPA's Non-Coincident Peak (NCP) demand requirements and MMPA's Coincident Peak (CP) demand requirements with MISO. In accordance with Department of Commerce (DOC) instruction and in compliance with MISO, MMPA uses its CP demand requirements for planning purposes in this IRP.

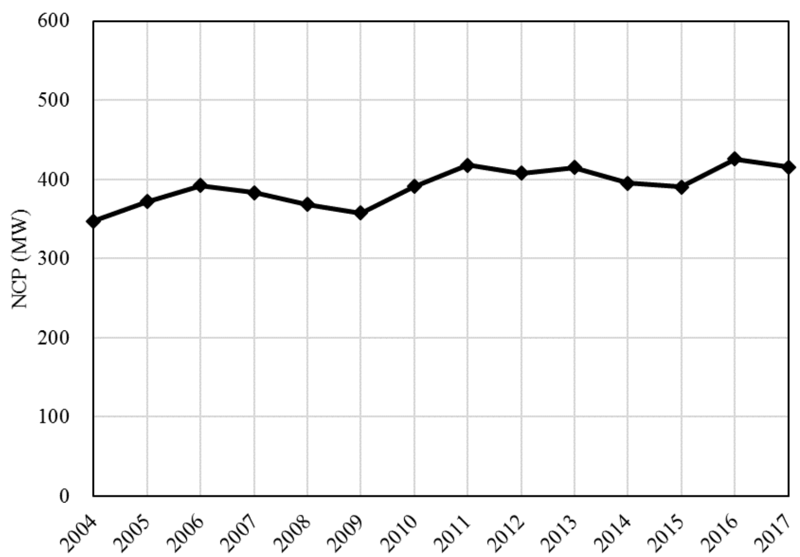
Historical 1.4% NCP Demand Growth Rate

Over the period 2004 to 2017, MMPA member NCP demand requirements grew at a compound annual growth rate of approximately 1.4% for all twelve MMPA members.

The following graph shows historical MMPA member NCP demand requirements for the years 2004 to 2017, the time period for which data is available for all twelve member cities. MMPA only served a portion of Shakopee's load until 2009. Therefore, the data has been adjusted to include all of Shakopee's load. MMPA has not historically served Elk River, but the data has been adjusted to include this load.

The demands recognize a 2.3% transmission loss factor, and an 8.4% planning reserve margin. Actual planning reserve requirements have varied from 2004-2017, but for consistency across historic years, this IRP assumes 8.4% for all periods.

Minnesota Municipal Power Agency
Historical Member NCP Demand (MW)



Weather Normalized Load Factor Approach Used to Project Demand

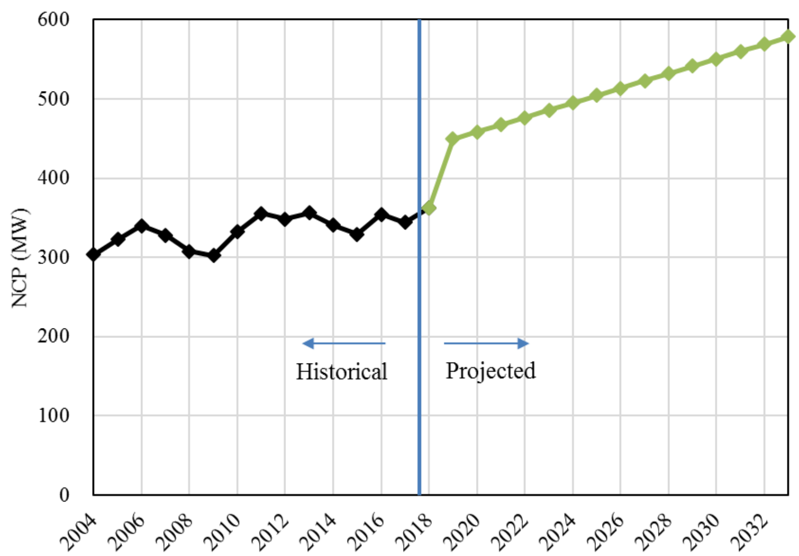
NCP demand for the Agency was projected using a weather normalized historical average load factor (approximately 56%) which was applied to MMPA's projected base energy requirements net of conservation.

Details on the inputs and assumptions of the methodology can be found in Appendix A.

Projected 1.8% NCP Demand Growth Rate without New Conservation

MMPA's projected NCP demand growth rate without new conservation is 1.8% for the 2019-2033 projection period. The following graph shows historical and projected MMPA NCP demand requirements for the years 2004 to 2033. The demands recognize a 2.3% transmission loss factor, and an 8.4% planning reserve margin.

Minnesota Municipal Power Agency
Historical & Projected Base Member NCP Demand (MW)
Without New Conservation



New Conservation Assumed to Reduce NCP Demand Growth Rate By 1.0%

New conservation measures are assumed to reduce the annual growth rate of MMPA's NCP requirements by 1.0%. The base case of 1.3% conservation does not translate into a 1.3% reduction in the demand growth rate because the requirements for CIP savings calculations are based upon a lagging 3-year average of MMPA's power consumption. Section 6 discusses in detail MMPA's current and future conservation efforts.

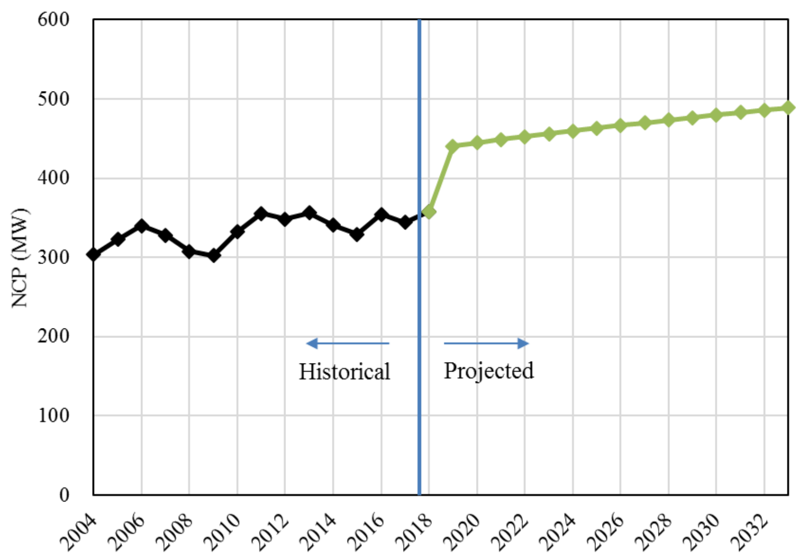
Projected 0.8% NCP Demand Growth Rate with New Conservation

MMPA's projected NCP demand growth rate including new conservation is 0.8% for the 2019-2033 projection period, shown in the table below.

	2019-2033
NCP Growth Rate Without New Conservation	1.8%
Effect of Conservation	1.0%
NCP Growth Rate With New Conservation	0.8%

The following graph shows historical and projected MMPA NCP demand requirements for the years 2004 to 2033. Both recognize a 2.3% transmission loss factor, and an 8.4% planning reserve margin.

Minnesota Municipal Power Agency
Historical & Projected Conservation-Adjusted
Member NCP Demand (MW)



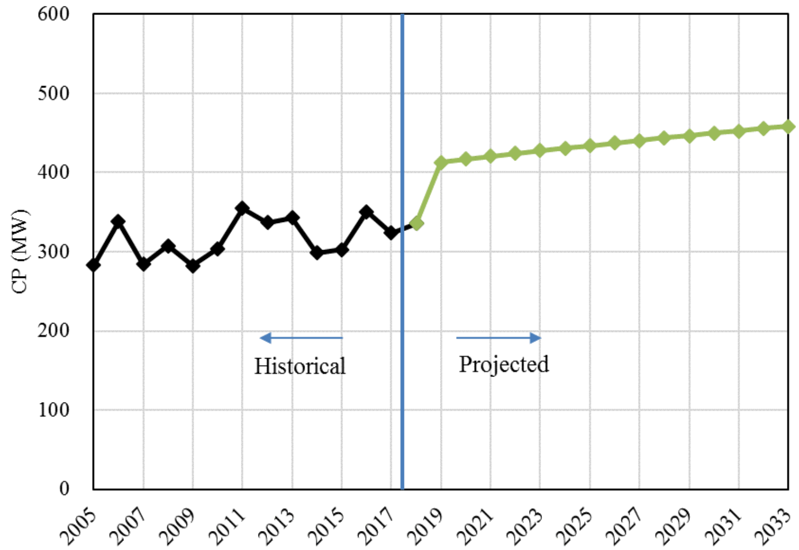
Coincidence Factor Approach Used to Project CP Demand

MMPA's demand at the time of MISO's peak (CP demand) was projected using a coincidence factor approach. An average historical coincidence factor (for summer months during the years 2005 to 2016, approximately 94%) was utilized to obtain MMPA's CP demand projection. Details on the methodology can be found in Appendix A.

Projected 0.8% CP Demand Growth Rate with New Conservation

MMPA's projected CP demand growth rate including new conservation is 0.8% for the 2019-2033 projection period. The following graph shows historical and projected MMPA CP demand requirements for the years 2005 to 2033. Because MISO's market opened in 2005, coincident peak data is not available in 2004. This data includes conservation adjustments, transmission losses of 2.3%, and a planning reserve margin of 8.4%.

Minnesota Municipal Power Agency
Historical & Projected Conservation-Adjusted Member CP Demand (MW)



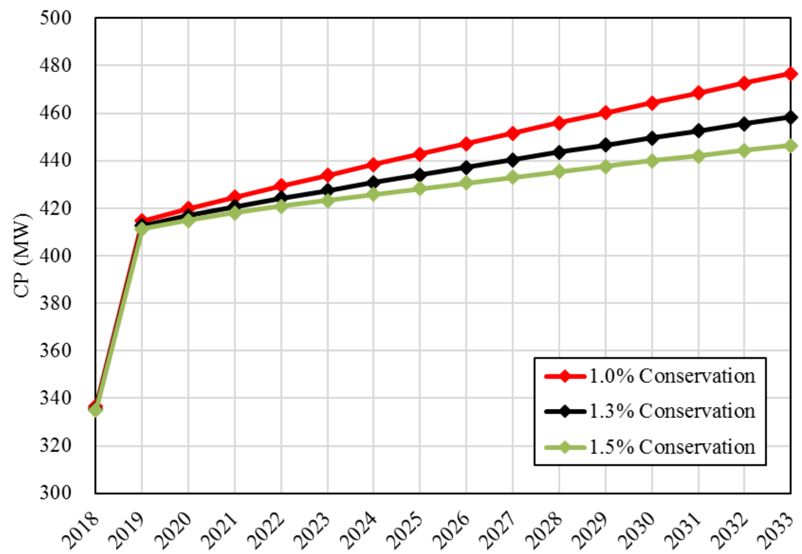
MMPA uses CP demand requirements for planning purposes in this IRP.

Lower Conservation Rates Would Increase Capacity Requirements

Lower conservation rates would increase capacity requirements. This IRP assumes a 1.3% energy conservation rate for planning purposes, however, high and low cases of 1.5% and 1.0% are also considered. See Section 6 for further details on conservation.

The graph below shows MMPA's CP demand projections based upon 1.0%, 1.3%, and 1.5% conservation levels. Both sets of projections recognize a 2.3% transmission loss factor, and an 8.4% planning reserve margin.

Minnesota Municipal Power Agency
Projected Conservation-Adjusted CP Demand (MW)



Lower Population Growth Rate Would Lower Electric Load Growth

Slower population growth correlates with slower load growth in demand projections. Demand is calculated using energy projections which are correlated to population growth. A comparison of historical and projected population compounded annual growth rates for MMPA member cities shows a deceleration in population growth across all MMPA members for the projection period. Please see Section 4 for details.

Additional Members Would Increase Demand Requirements

MMPA's projected demand requirements would increase if the Agency were to take on additional members. This IRP assumes that the 12-member Agency does not take on any additional members during the projection period.

Large Retail Load Additions Would Increase Demand Requirements

MMPA's projected demand requirements would increase if its members were to take on new large retail loads. This IRP does not include any new large retail loads during the projection period.

Less Supply from WAPA Would Increase Demand Requirements

Two of MMPA's members currently receive allocations of power (approximately 15.7 MW) from the WAPA. Both members have long-term contracts for these power allocations. However, WAPA could reduce the amount of energy and power available to its customers in the future. This would represent a policy change from the past. If WAPA decreases the power available to its customers, MMPA's demand requirements would increase, because the Agency provides all of the demand to these two members that is not supplied by WAPA. This IRP assumes that WAPA allocations remain at the current contract amounts throughout the projection period.

The Effect of Electric Vehicles on Peak Demand is Unclear

In Section 4, it was discussed that MMPA's energy requirements would increase with an increase in electric vehicle use. However, the effect of electric vehicle use on demand is unclear.

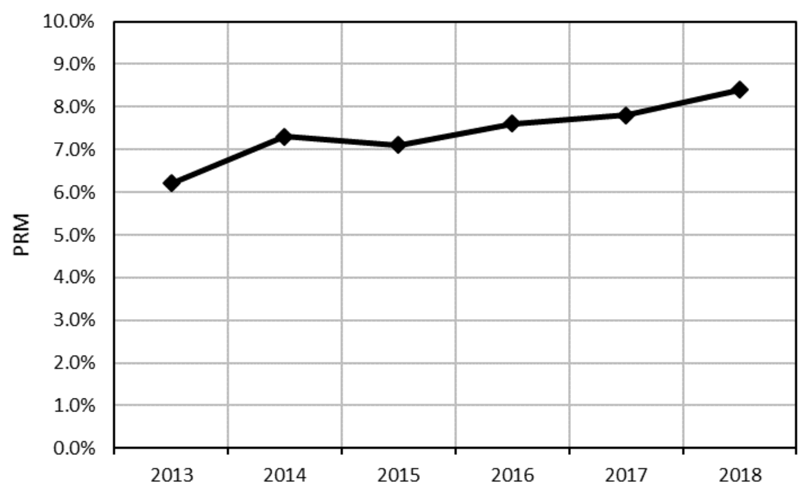
The California Energy Commission (CEC) report discussed in Section 4 estimated electric vehicles in California could add more than 1 GW of peak demand by 2025, assuming California reaches its goal of 1.5 million zero-emission vehicles (approximately 5% of all vehicles). The report described an electric vehicle charging profile consisting of a small at-home charging load ramp in the morning, work-place charging during the day, and a steep at-home charging load ramp in the early evening. This charging profile would likely increase peak demand. However, an alternative electric vehicle charging profile, where the majority of charging occurs during overnight off-peak hours, may have limited impact on peak demand.

This IRP assumes no increase in demand requirements during the projection period because the level of electric vehicle penetration and the effect of electric vehicles on peak demand is not clear.

Higher MISO Planning Reserve Margin (PRM) Would Increase Capacity Requirements

Historically, MISO's planning reserve margin (PRM) has varied by planning year as shown in the chart below. This IRP uses a PRM of 8.4%, consistent with the most recent planning year, to calculate MMPA's planning resource margin requirements (PRMR). Future increases in PRM would increase MMPA's capacity requirements.

MISO Planning Reserve Margin



Higher Transmission Losses Would Increase Capacity Needs

This IRP assumes a 2.3% transmission loss factor for the projection period. Historically, transmission losses have varied by MISO Zone, Local Balancing Area (LBA), and planning year.

MMPA's entire load is in MISO Zone 1. The Agency currently serves load in two LBAs within Zone 1. The vast majority of MMPA's load is in the NSP LBA, where transmission losses are 2.4%. The remainder of MMPA's load is in the OTP LBA, with transmission losses of 3.1%. In October 2018, MMPA will begin serving Elk River load in the GRE LBA, with transmission losses of 1.4%. For the purposes of this IRP, the Agency assumes aggregate 2.3% transmission losses.

Future increases in transmission losses would increase MMPA's capacity needs.

Higher Generation Forced Outage Rate Would Reduce Recognized Capacity

An increased generation forced outage rate, as measured by equivalent demand forced outage rate (EFORd), would decrease the capacity market credits MMPA would receive for its generation resources. EFORds for the planning horizon were based on the resource-specific EFORds for the 2018-19 planning year. If EFORds increase during the planning horizon, MMPA's capacity requirements would increase. Conversely, if EFORds decrease, MMPA's capacity requirements would decrease.

MMPA's Energy, NCP Demand, And CP Demand Projections

The table below summarizes MMPA's energy, NCP demand, and CP demand projections from 2019 to 2033. The energy projections have been adjusted for conservation and WAPA allocations. The NCP and CP projections have been adjusted for these same factors, as well as for transmission losses and the MISO PRM.

Minnesota Municipal Power Agency
Energy and Demand Projections

Year	Energy (MWh)	MMPA NCP (MW)	MMPA CP (MW)
2019	1,925,452	440.4	412.6
2020	1,950,524	444.9	416.9
2021	1,963,088	449.0	420.7
2022	1,979,777	452.7	424.2
2023	1,995,207	456.2	427.5
2024	2,016,234	459.8	430.8
2025	2,025,785	463.2	434.0
2026	2,040,921	466.6	437.2
2027	2,055,635	469.9	440.3
2028	2,076,571	473.4	443.6
2029	2,084,796	476.5	446.6
2030	2,099,060	479.8	449.6
2031	2,112,665	482.9	452.5
2032	2,133,062	486.2	455.6
2033	2,140,227	489.1	458.3

Section 6. Energy Conservation and Demand Side Management

This section discusses MMPA's energy conservation and demand side management efforts. The Agency's energy conservation programs delay the need for new generation and reduce energy consumption.

State Legislature Established a CIP Energy Savings Target

In 2007, the State Legislature revised the Conservation Improvement Program (CIP) statute to set an annual energy savings goal for each electric utility beginning in 2010.

Seven of the twelve MMPA member communities participate in the CIP program managed by the Agency. The other five member communities manage their own energy efficiency programs at the municipal utility level.

In 2017 State Legislature Exempted Small Utilities from CIP

In 2017, the State Legislature revised the CIP statue to exempt electric utilities with fewer than 1,000 customers from participating in the program. Two MMPA member communities qualify for this exemption, however, both utilities have opted to continue to participate.

MMPA Strives to Meet Its CIP Spending Requirement and Energy Savings Target

MMPA strives to meet its CIP spending requirement and energy savings target. MMPA has undertaken significant efforts to develop a CIP portfolio to meet its CIP energy savings target now and into the future.

Agency-Managed CIP Spending 2015-2017

MMPA has consistently met its annual CIP spending goal of 1.5%. The table below shows annual CIP dollars spent and the percentage of gross operating revenue (GOR) over the period 2015 through 2017.

CIP Spending – MMPA-Managed Portfolio

	2015	2016	2017
CIP Spending	$522,895	$537,421	$558,071
% of GOR	1.5%	1.5%	1.5%

Agency-Managed CIP kWh Savings 2015-2017

MMPA's annual CIP kWh savings are slightly below the State's savings goal of 1.5%. The table below shows annual kWh saved over the period 2015 through 2017.

CIP Energy Savings – MMPA-Managed Portfolio

	2015	2016	2017
kWh Savings	3,767,808	4,889,312	4,547,594
% of Sales	1.1%	1.4%	1.3%

Agency-Managed CIP Program Cost $0.12/kWh of Energy Saved

Based upon data for 2017, MMPA's CIP program cost an average of $0.12/kWh of electricity saved. MMPA's Agency-managed CIP portfolio aims to incorporate programs that help to maintain an average rebate cost-to-electricity savings ratio of $0.10/kWh or less.

This IRP Assumes 1.3% Energy Savings for Projections

This IRP assumes a CIP savings rate of 1.3%, although a low case of 1.0% and a high case of 1.5% were also analyzed. The Agency strives for a 1.5% savings rate, however, planning processes need to take into consideration the uncertainties associated with longer term effectiveness of CIP programs and the possibility of diminishing returns.

Lighting Rebates Are a Cost-Effective Use of CIP Funds

In 2017, 54% of MMPA's Agency-managed CIP rebate spending went toward lighting projects. Lighting rebates are a cost-effective means of achieving energy savings. The table below highlights the return on investment in MMPA's 2017 CIP cycle.

Lighting Program Effectiveness – MMPA-Managed Portfolio

Program	kWh saved	Cost/kWh saved
Commercial Lighting – New	349,850	$0.10
Commercial Lighting - Retrofit	2,719,646	$0.07
Residential LED	16,834	$0.23
Lighting Giveaway	137,975	$0.21
LED Street Lighting	191,685	$0.15
All Lighting Combined	3,415,990	$0.09

Rebates with High Energy Savings Potential

The appliance recycling bonus rebate, the variable frequency drive rebate, and custom rebates all have high energy savings potential. The appliance recycling bonus rebate ($0.05/kWh electricity saved) creates customer incentives to unplug inefficient refrigerators and freezers and the variable frequency drive rebate ($0.05/kWh electricity saved) incentivizes improving heating, ventilation, and air conditioning (HVAC) system operation.

Custom rebates are unique in that they give MMPA flexibility to support its members' customers on projects with high energy savings potential. Custom commercial and industrial projects also achieve a good return on investment, averaging $0.07 spent per kWh of electricity saved in 2017. Custom rebates made up 7% of MMPA's Agency-managed CIP rebate spending in 2017.

A Variety of Programs Offered to Residential, Commercial, and Industrial Customers

Programs offered in the Agency-managed 2018 CIP Portfolio include:

Residential:

- ENERGY STAR Appliance Rebate (Clothes Washer, Dishwasher, Refrigerator, Freezer, Dehumidifier)
- Secondary Refrigerator or Freezer Recycling Rebate
- LED Lighting Rebate
- Quality Installed Central Air Conditioning (AC) and Air Source Heat Pump Rebate
- AC Tune Up Rebate
- Custom Rebates

Commercial and Industrial:

- Lighting Retrofit Rebate
- Lighting New Construction Rebate
- Variable Frequency Drives (VFD) Rebates
- Vending Machine Controller Rebate
- Custom Rebates

Members Pursue Direct Low-Income CIP Projects

In 2017, the Agency-managed CIP members spent an estimated $45,570 on low-income energy conservation projects.

Low-income spending is measured at the city level and each member city must meet its own individual spending requirement. MMPA continues to pursue low-income programs that provide direct benefits to low-income customers such as purchasing energy efficient lighting and appliances for section 8 housing and offering free light bulbs to low-income customers.

CIP Energy Savings Goals Will Become More Challenging to Achieve in the Future

It is anticipated that CIP energy savings goals will become more challenging to achieve in the future. Lighting rebates and custom rebates for equipment such as HVAC equipment are some of the most successful programs. These installations have long useful lives, therefore, in the future, there will be fewer available projects for updates. Additionally, energy-saving technological advancements are likely to slow down in areas such as lighting.

Despite this, MMPA still believes it will have a continuing energy savings impact during the 2019-2033 projection period by focusing on developing CIP strategies with the lowest cost per kWh of electricity saved, focusing on new energy-efficient technologies, and communicating with customers.

Industrial and Commercial Programs Are Important to Program Success

Participation by industrial and commercial customers is critical for achieving energy savings goals. Industrial and commercial customers are larger energy users and therefore have greater energy savings potential. MMPA works to create relevant, cost-effective programs for these users.

MMPA Regularly Reevaluates Its CIP Offerings

MMPA continues to evaluate its program offerings and consider new programs. MMPA aims to direct its CIP spending to the most cost-effective programs. Since the 2013 IRP filing, MMPA added residential rebates for freezers and dehumidifiers, recycling of secondary freezers, and commercial rebates for a variety of new LED lamps and fixtures.

MMPA Continues to Reevaluate Demand Side Management Programs

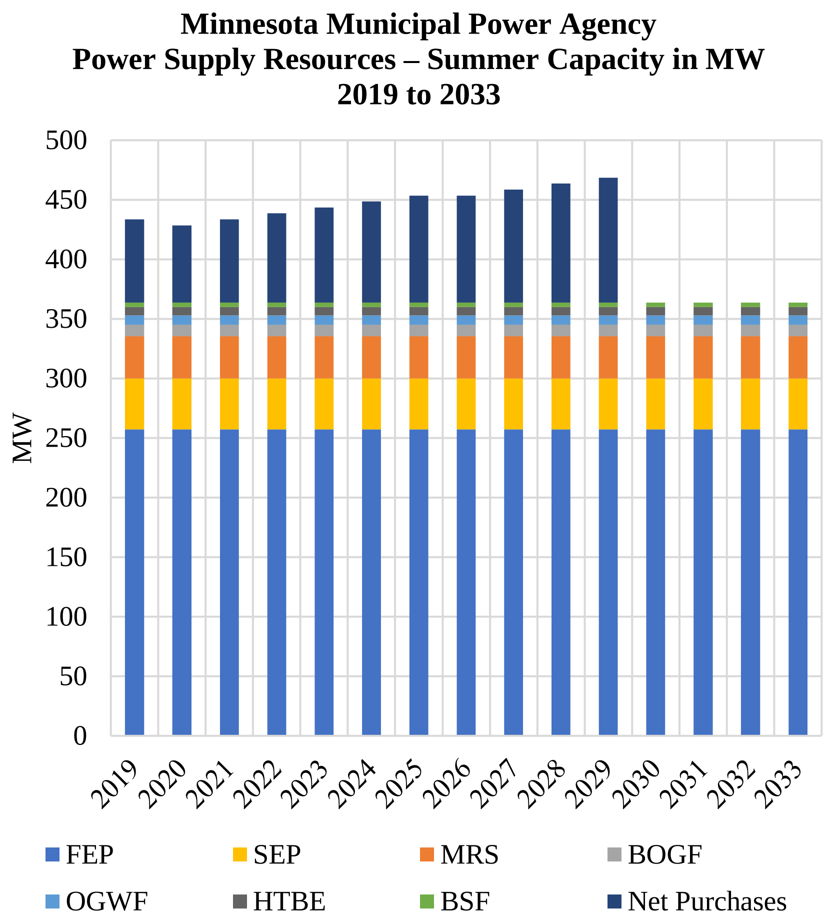
MMPA currently has no demand side management programs, but continues to reevaluate potential options. The Agency had a load curtailment program and retired it when it became a less competitive option to acquire capacity as market prices for capacity became less expensive.

Section 7. Existing Resources

MMPA's existing resource portfolio is a mix of owned generation and power purchase agreements and a combination of renewable and conventional resources.

434 MW of Projected Power Supply Resources in 2019

MMPA projects that its power supply portfolio will consist of 434 MW of both contractual resources and Agency-owned generation for planning year 2019. The graph below shows MMPA's existing resources for the period 2019 to 2033.



Key:

FEP: Faribault Energy Park
HTBE: Hometown BioEnergy
MRS: Minnesota River Station
BOGF: Black Oak Getty Wind Farm
Net Purchases: Bilateral Purchases
OGWF: Oak Glen Wind Farm
BSF: Buffalo Solar Facility
SEP: Shakopee Energy Park

MISO Capacity Measured by Unforced Capacity (UCAP)

MISO capacity is measured by Unforced Capacity (UCAP). UCAP is calculated by multiplying the Installed Capacity (ICAP) of a generating resource by 1 minus the Effective Forced Outage Rate (EFORd). Once the UCAP of a resource is calculated, market participants can convert UCAP to Zonal Resource Credits (ZRCs) to get capacity.

FEP Projected UCAP: 257.3 MW

Faribault Energy Park (FEP) is the first power supply resource financed and built by MMPA. The plant was built in two phases, with simple cycle operation beginning in April 2005. The combined cycle phase began operations in the summer of 2007, improving the fuel efficiency and increasing the maximum accredited summer output of the plant to 261 MW. The plant uses natural gas as its primary fuel.

FEP is an innovative power plant that uses a series of created wetlands for water management at the plant. Rainwater is collected and filtered before being used for steam production and equipment cooling. The wetlands area is open to the public as a park with several small trails.

The plant is also designed to be a "working classroom," with an observation room where visitors can view both the steam turbine and the plant's control room.

FEP's ICAP for PY 2018 is 261.3 MW. The EFORd used to calculate FEP's 2018 UCAP is 1.53%. This IRP assumes that FEP's EFORd will continue to be 1.53% for the 15-year planning horizon of 2019-2033.

FEP

	2018	**2019-2033**
ICAP	261.3	261.3
EFORd	1.53%	1.53%
UCAP/ZRC	257.3	257.3

SEP Projected UCAP: 42.6 MW

Shakopee Energy Park (SEP) is a 46.4 MW distributed energy resource. Located in Shakopee near Canterbury Park, SEP uses fuel-efficient reciprocating engines to generate local, reliable power for the City of Shakopee as well as contributing to the overall power supply for all MMPA member communities.

SEP's ICAP for PY 2018 is 46.4 MW. The EFORd used to calculate SEP's 2018 UCAP is 8.19%. This IRP assumes that SEP's EFORd will continue to be 8.19% for the 15-year planning horizon of 2019-2033.

SEP

	2018	**2019-2033**
ICAP	46.4	46.4
EFORd	8.19%	8.19%
UCAP/ZRC	42.6	42.6

MRS Projected UCAP: 35.6 MW

The Minnesota River Station (MRS) plant is a peaking resource. The City of Chaska, one of the Agency's members, owns the plant and sells the entire output to MMPA under a long-term contract. MRS became operational in the summer of 2001 and is accredited for approximately 40 MW in the summer. Minnesota River Station uses natural gas as its primary fuel.

MRS's ICAP for PY 2018 is 39.6 MW. The EFORd used to calculate MRS' 2018 UCAP is 10.00%. This IRP assumes that MRS's EFORd will continue to be 10.00% for the 15-year planning horizon of 2019-2033.

MRS

	2018	**2019-2033**
ICAP	39.6	39.6
EFORd	10.00%	10.00%
UCAP/ZRC	35.6	35.6

BOGF Projected UCAP: 9.7 MW

At the end of 2016, the Minnesota Municipal Power Agency (MMPA) expanded its portfolio of renewable resources to include power from the 78-megawatt (MW) Black Oak Getty Wind Farm (BOGF) located in Stearns County, Minnesota.

MMPA signed a long-term contract with Sempra U.S. Gas & Power for the output of the Black Oak Getty Wind Farm. The wind farm, composed of 39 wind turbines, entered commercial operation in December 2016. The term of the contract is 30 years.

BOGF ICAP for PY 2018 is 78 MW. For wind resources, MISO uses capacity credit instead of EFORd. The UCAP is simply calculated by multiplying the ICAP by the capacity credit. The capacity credit used to calculate BOGF's 2018 UCAP is 12.44%. This IRP assumes that BOGF will continue to receive the 2018 capacity credit for the 15-year planning horizon.

BOGF

	2018	**2019-2033**
ICAP	78	78
Capacity Credit	12.44%	12.44%
UCAP/ZRC	9.7	9.7

HTBE Projected UCAP: 7.2 MW

Hometown BioEnergy (HTBE) is an 8 MW biomass facility, located in the MMPA member community of Le Sueur. It provides dispatchable, on-peak renewable energy to the Agency.

Hometown BioEnergy supports the local community by collecting and processing local wastes to create a renewable source of electricity that flows directly into the Le Sueur power system.

The facility was recognized by POWER Magazine as a 2014 Top Renewable Plant.

HTBE ICAP for PY 2019 is projected to be 8 MW. The EFORd used to calculate HTBE's 2019 UCAP is 10.42%, which is the class average for diesel generation in MISO in 2018. This IRP assumes that HTBE's EFORd will match the 2018 class average for diesel generation for the IRP period through 2033.

HTBE

	2019-2033
ICAP	8
EFORd	10.42%
UCAP/ZRC	7.2

OGWF Projected UCAP: 7.6 MW

The 44 MW Oak Glen Wind Farm (OGWF) is MMPA's first owned wind farm and is located near Blooming Prairie, Minnesota.

The U.S. Department of Energy awarded OGWF with the "2012 Public Power Wind Award" for leadership, innovation, project creativity, and benefits to customers. OGWF's innovative ownership and financial structure qualified the wind project to receive a $25.4 million federal grant.

OGWF ICAP for PY 2018 is 44 MW. For wind resources, MISO uses capacity credit instead of EFORd. The UCAP is simply calculated by multiplying the ICAP by the capacity credit. The capacity credit used to calculate OGWF's 2018 UCAP is 17.35%. This IRP assumes that OGWF will continue to receive the 2018 capacity credit for the 15-year planning horizon.

OGWF

	2018	**2019-2033**
ICAP	44	44
Capacity Credit	17.35%	17.35%
UCAP/ZRC	7.6	7.6

Buffalo Solar Projected UCAP: 3.6 MW

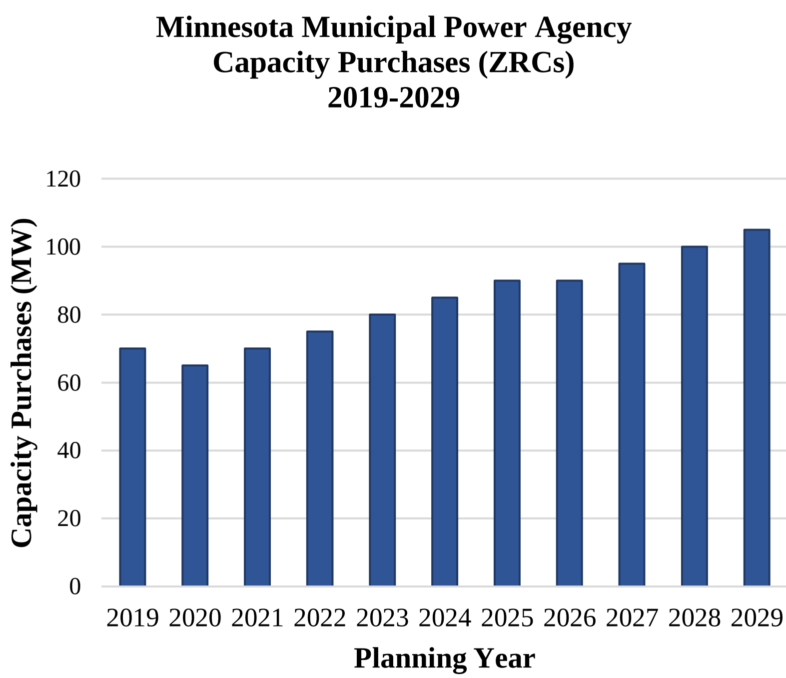
The Buffalo Solar Facility (BSF), a 7.1 MW AC utility-scale solar facility located in the Agency's member community of Buffalo, entered commercial operation at the end of 2017. MMPA signed a 22.5-year, long-term contract with HQC Tatanka Wi Solar Power Generation LLC, for the output of the solar facility.

BSF

	2018	**2019-2033**
ICAP	7.1	7.1
Capacity Credit	50.00%	50.00%
UCAP/ZRC	3.6	3.6

MMPA Purchased Capacity for PY 2019-2029

MMPA has purchased between 65 and 105 MW of MISO Zonal Resource Credits (ZRCs) for 2019 through 2029.



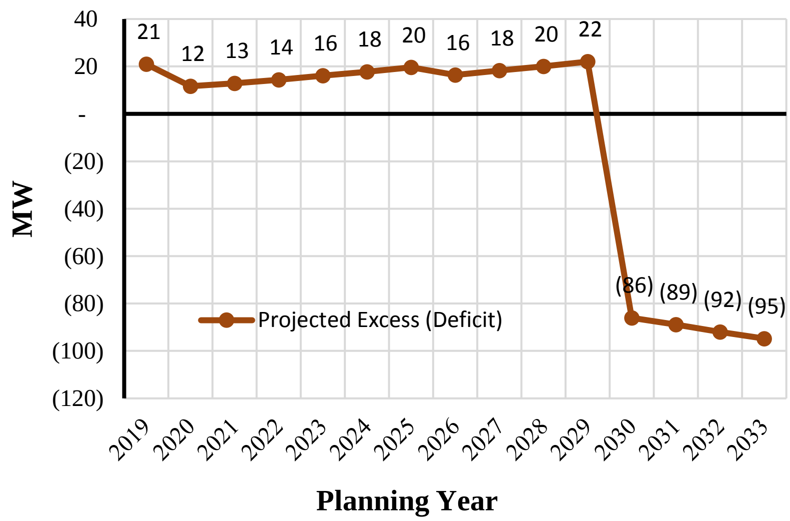
Section 8. Additional Capacity Requirements

This section describes MMPA's projected additional capacity requirements over this IRP's planning period.

No Capacity Needed Until 2030

MMPA projects that it will not need new capacity until planning year 2030. The chart below shows MMPA's projected capacity position by year during the projection period.

Minnesota Municipal Power Agency
Projected Capacity Position
2019-2033



Projected Capacity Need Grows From 86 MW in 2030 To 95 MW in 2033

MMPA projects that its first year of capacity need is PY 2030 for 86 MW. The expiration of a capacity contract and member load growth are the main reasons for the capacity need.

Planning Reserve Margin Requirement of 8.4% Is Assumed

MMPA currently participates in the MISO PRM pool. This IRP assumes a PRM of 8.4% for the projection period, as discussed in previous sections.

Transmission Losses Assumed to Be 2.3%

Transmission losses of 2.3% are assumed for this IRP, as discussed in previous sections.

Section 9. Planning Approach

This section outlines MMPA's planning approach.

No Capacity Needed Until PY 2030

As discussed in Section 8, MMPA projects no capacity need until planning year 2030.

Maintain Flexibility in Time of Technological Transition

MMPA seeks to maintain flexibility in its power supply plan during a time of technological change. The rapid changes occurring with renewable and storage technologies make flexibility vital to any planning process. Securing additional capacity in the market allows MMPA to later reevaluate the changing market and capture opportunities that do not currently exist.

Continue to Reevaluate Feasibility of Resource Alternatives

MMPA will continue to reevaluate resource alternatives to determine what option is the most effective to meet future requirements. Included in these alternatives is the option to buy capacity. MMPA maintains long term relationships with many MISO market participants and looks for opportunities to buy capacity when cost effective.

Committed to Renewable Energy

The Agency is committed to renewable energy. MMPA plans to meet or exceed Minnesota's Renewable Energy Standard (RES). Section 12 further discusses MMPA's plan to meet renewable requirements.

Section 10. Short-Range Plan

This section outlines MMPA's short-range action plan.

Projected Capacity Needs Met Through Planning Year 2029

MMPA is not projected to need capacity until planning year 2030.

MMPA Signed 170 MW Wind PPA

MMPA has signed a wind PPA for 170 MW of energy. The resource is anticipated to begin commercial operation at the end of 2019. This PPA will help MMPA to meet the Renewable Energy Standard that is discussed in Section 12 and to meet its incremental energy needs with renewable energy.

Cover Capacity Needs in the Short-Term Market

As discussed in Section 8, MMPA is projected to have adequate capacity through planning year 2029. However, in the future if MMPA instead has a deficit, the incremental difference could be covered in the short-term capacity market.

Continue to Develop and Market Cost-Effective Conservation Programs

MMPA will continue to develop and market cost-effective conservation programs for its member utilities to offer to their retail customers. The Agency's philosophy is to focus on programs that generate the most energy savings per dollar spent. MMPA also remains committed to providing energy efficiency programs that benefit Minnesota's low-income households.

Section 11. Long-Range Plan

This section describes MMPA's long-range plan.

Capacity Not Needed Until Planning Year 2030

MMPA is not projected to need capacity until planning year 2030. The costs of different technologies for capacity are expected to change by the time the capacity is needed. For this reason, discussions with the Department of Commerce staff concluded that a detailed evaluation of resource alternatives is not needed for this IRP.

Monitor Cost of Generation Technologies

During this time, MMPA will continue to monitor the cost of generation technologies. In addition, MMPA will track Federal and State regulations, consumer preferences, and advances in technology.

Evaluate Resource Alternatives

When MMPA's capacity need becomes near term, the Agency would conduct a detailed evaluation of resource alternatives. The Agency anticipates considering new generation and power purchases to meet its needs. For new generation, a variety of technologies would be considered such as simple cycle gas, combined cycle gas, reciprocating engines, battery storage, solar, and wind.

Consider Capital, Operating, Fuel, and Externality Costs

In its evaluation of resources, MMPA would consider capital, operating, fuel, and externality costs of all resources. Externality costs would include environmental and regulatory costs of emissions as determined by the PUC.

Section 12. RES Compliance and Rate Impact

This section describes MMPA's efforts toward meeting the State of Minnesota's Renewable Energy Standard (RES) and the estimated rate impact of complying with the RES.

RES Requirement Projected to Grow to 511,000 MWh

MMPA's annual RES requirements are projected to grow from approximately 312,000 in 2019 to 511,000 in 2033. This is mainly because of ERMU's addition as the twelfth member to MMPA as well as the increasing RES requirements. The RES requirements are based on total retail electric sales. The calculations account for a 4.49% system loss between wholesale and retail sales. The table below summarizes the RES obligation for MMPA for the period 2019-2033.

Minnesota Municipal Power Agency
Projected RES Requirements

Year	Projected Wholesale Load (MWh)	RECs for RES Obligations
2019	1,925,452	312,617
2020	1,950,524	372,574
2021	1,963,088	374,974
2022	1,979,777	378,162
2023	1,995,207	381,109
2024	2,016,234	385,125
2025	2,025,785	483,687
2026	2,040,921	487,301
2027	2,055,635	490,814
2028	2,076,571	495,813
2029	2,084,796	497,777
2030	2,099,060	501,183
2031	2,112,665	504,431
2032	2,133,062	509,301
2033	2,140,227	511,012

RECs for Clean Energy Programs

In addition to its RES obligation, MMPA has retired RECs for its green pricing program and Clean Energy Choice Programs. While RECs retired for these programs are not significant (approximately 6,000 RECs for 2017), participation in these programs is increasing and would increase the total RECs needed.

Notwithstanding the foregoing, MMPA's current and future resources are projected to satisfy all of its future REC obligations**.**

970,000 RECs in Inventory

The Agency currently has over 970,000 RECs in its inventory. MMPA actively follows the REC markets and seeks opportunities to buy RECs to satisfy its future requirements. Below is the breakdown of MMPA's current REC inventory:

2014 Vintage RECs	119,648
2015 Vintage RECs	176,349
2016 Vintage RECs	169,724
2017 Vintage RECs	398,221
2018 Vintage RECs	109,559
Total	973,501

Five Existing Renewable Resources Projected to Generate 466,000 MWh/Year

MMPA's five existing resources are projected to generate approximately 466,000 MWh per year.

The table below shows the projected annual generation from these existing renewable resources:

Resource	Annual Generation (MWh)
Black Oak Wind Farm	307,000
Oak Glen Wind Farm	132,000
Buffalo Solar	14,000
Hometown BioEnergy	12,000
Hometown Wind	800
Total	465,800

Signed PPA Projected to Generate 600,000 MWh/Year

MMPA has signed a 30-year wind power purchase agreement with NextEra for 170 MW of generating capacity from the Dodge County Wind Farm. The facility has not yet been constructed, but has a contract commercial operation deadline of December 2019. The wind farm is projected to generate approximately 600,000 MWh of renewable energy per year.

MMPA Projects Meeting All of Its Incremental Energy Needs with Renewables

In 2033, MMPA's energy requirements of 2,140,227 MWh will be 214,776 MWh over its projected 2019 requirements. MMPA's renewable energy requirement for 2033 of 511,012 MWh is 238% of its incremental energy needs. By satisfying the RES, MMPA will meet all of its incremental energy needs through renewables. The effects of MMPA's conservation efforts are included in the base calculations.

MMPA Is Positioned to Meet the RES

MMPA is positioned to continue to meet the RES through its mix of purchases and resources.

Rate Impact of Complying with RES

MMPA's 2005 to 2017 RES rate impact ranged between 0.00 cents per kWh and 0.96 cents per kWh.

MMPA's projected RES rate impact for 2019-2033 ranges between 0.64 cents per kWh and (0.53) cents per kWh.

Details of these projections are included in Appendix C.

Dodge County Project Necessary to Meet RES Rate Impact Projections

The Dodge County project is necessary to meet the RES rate impact projections. MMPA's competitively priced PPA with Dodge County Wind Farm reduces the rate impact beginning with 2020. This project is projected to provide benefits between 0.09 cents per kWh and 0.55 cents to kWh.

Greenhouse Gas Emission Reduction Goals Were Achieved in 2015 and Are Projected to Be Achieved in 2025

MMPA's generation assets and power purchase agreements that contribute to meeting the RES also support meeting Minnesota's greenhouse gas emission reduction goals that are established in Minn. Stat. § 216H.02. Minnesota established a goal to reduce statewide greenhouse gas emissions across all sectors at least 15% below 2005 levels in 2015 and at least 30% below 2005 levels in 2025. The following table summarizes MMPA's greenhouse gas reductions for 2015 and 2025.

Minnesota Municipal Power Agency
Greenhouse Gas Reductions from 2005 Levels

	2015	2025
Total Emissions (lbs CO_2)	34%	63%
Emission Rate (lbs CO_2/MWh)	42%	76%

Section 13. MMPA's Plan Is in The Public Interest

This section discusses how MMPA's Integrated Resource Plan is in the public interest.

MMPA's Plan Provides Flexibility

MMPA's IRP gives the Agency flexibility to accommodate future uncertainties such as technological changes, penetration of electric vehicles, and energy policy. The Agency created this flexibility by purchasing capacity through planning year 2029. As 2029 approaches, MMPA will reevaluate load and costs to determine the best options for meeting its future capacity and renewable energy requirements.

MMPA's Plan Limits Environmental Effects

The Agency's plan limits negative environmental effects. MMPA projects that 53% of its wholesale sales will be from renewable resources in 2025. MMPA also continues to pursue increased energy conservation.

MMPA's Plan Meets the Public Interest Criteria in Rule 7843

MMPA's plan meets the public interest criteria set out in Commission Rule 7843.0500 Subp. 3, which are:

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

MMPA's plan includes a diverse set of resources to serve its load. The Agency's portfolio has both owned and contracted renewable and conventional resources. MMPA seeks to maintain flexibility in its power supply plan during a time of technological change. The rapid changes occurring with renewable and storage technologies make flexibility vital to any planning process. Securing additional capacity in the market allows MMPA to later reevaluate the changing market and capture opportunities that do not currently exist. This plan enhances the Agency's ability to respond to change during this transitional period for the energy industry. It also limits the risk of adverse effects. By including renewable resources in its portfolio and promoting energy conservation, the Agency balances socioeconomic and environmental considerations.

Appendix A. Load Projection Methodology

This appendix describes the methodology used to project MMPA's energy and demand requirements for this Integrated Resource Plan.

Members' Energy Usage Was Projected with A Linear Regression Model

MMPA member energy usage was projected using linear regression analysis. The energy usage for three of MMPA's member cities (East Grand Forks, Buffalo, and Elk River) was projected separately from that of the other nine members. Those four projections were then combined to obtain the entire Agency's projected energy. The MMPA9 projection includes the member cities of Anoka, Arlington, Brownton, Chaska, Le Sueur, North St. Paul, Olivia, Shakopee and Winthrop. The historical monthly energy data sets for these four projections are as follows:

- **MMPA9**: Monthly energy usage from 1996–2017
- **East Grand Forks**: Monthly energy usage from 1996–2017
- **Buffalo**: Monthly energy usage from 2000–2017
- **Elk River**: Monthly energy usage from 2004–2017

Data constraints for East Grand Forks and Buffalo prompted the separate projections for those cities. Elk River was projected separately because MMPA begins serving its load in October 2018. Total MMPA energy requirements were projected by adding the results of these four regression models.

Throughout this appendix, all 12 MMPA member cities are referred to as MMPA12 and all 11 MMPA member cities, excluding Elk River, are referred to as MMPA11.

Explanatory Variables for Energy Projections Were Weather, Income, And Population

The explanatory variables used for the regression models were weather, income, and population.

<u>Weather</u>
Cooling degree days (CDD) and heating degree days (HDD) were both used as explanatory variables. All CDD and HDD data is supplied by the National Oceanic and Atmospheric Administration (NOAA). Historical CDD and HDD data for all member communities, except East Grand Forks, comes from the Minneapolis-St. Paul International Airport weather station. Historical CDD and HDD data for the East Grand Forks model comes from the Fargo weather station (the closest available). CDD and HDD projections are historical "normal" data from 1981-2010 (the latest "normal" data set available published by NOAA).

Income per Capita

Both historical and projected income data come from Woods and Poole Economics' *Minnesota State Profile 2017 State and County Projections to 2050*. This data is provided at the county level. The MMPA9 model uses a weighted average income variable, created by weighting each of those nine member cities' income per capita by the city's annual energy usage.

Population

Historical population data from 1988 to 2016 comes from the Minnesota State Demographic Center and the Metropolitan Council *Historic Household and Population Estimates*. Data was unavailable for the year 1989, so linear smoothing of 1988 and 1990 data was used. Population projections from 2019 to 2033 are based on actual data for 2016, annually increased by long term county population growth rates calculated from Woods and Poole projections.

All explanatory variables listed above were used in the MMPA9 model. For the East Grand Forks model, CDD and population were excluded because of low t-stat results. Minimal air conditioning load and a devastating 1997 flood likely explain the low t-stats for CDD and population, respectively.

Each model used monthly data to forecast monthly energy, which was then aggregated to provide annual energy projections.

Annual Energy Was Reduced by Conservation

Annual energy projections were decreased by 1.3% of the Agency's three-year rolling average retail energy usage. This reduction represents MMPA's assumption regarding new conservation measures.

Conservation levels of 1.0% and 1.5% were also analyzed, but the 1.3% base case was used for the purposes of this IRP. Conservation reductions lowered the compounded annual growth rate by 1.0%, resulting in a net annual growth rate of 0.8% for the base case energy usage.

Agency Energy Requirements Were Reduced By WAPA-Supplied Energy

Following adjustments for conservation, projected energy requirements were reduced by the energy that WAPA supplies to two MMPA member cities (Olivia and East Grand Forks). These WAPA allocations were assumed to remain at current levels throughout the projection period.

NCP Demand Was Projected Using a Weather Normalized Load Factor

MMPA's Non-Coincident Peak (NCP) demand requirements were projected by applying a weather normalized load factor to the Agency's energy projections. This weather normalized load factor of 55.9% was calculated as the average of annual weather normalized load factors from 2011 to 2017. The average load factor was then applied to the conservation-adjusted energy projections to obtain MMPA's projected NCP demand.

Demand at MISO's Annual Coincident Peak Was Projected Using A Coincidence Factor Approach

MMPA's demand at the time of MISO's peak (CP demand) was projected by applying a coincidence factor to the Agency's NCP projections. This coincidence factor of 93.9% was calculated as the average of monthly summer (June-September) coincidence factors from June 2005 to September 2016. The average coincidence factor was then applied to the NCP demand projections to obtain MMPA's projected CP demand.

CP Demand Was Adjusted for WAPA-Supplied Capacity

Like the energy projections, CP demand projections were reduced by the capacity that WAPA supplies to two MMPA member cities. These WAPA allocations were assumed to remain at the current contract levels throughout the projection period.

Capacity Requirements Include Losses and Reserves

The Agency's total capacity requirements are calculated by adding transmission system losses (2.3%) and planning reserve margin requirements (8.4%) to the projected CP demand requirements.

MMPA's entire load is in MISO Zone 1 and currently serves load in two Local Balancing Authorities (LBAs). The vast majority of MMPA's load is in the NSP LBA, where transmission losses are 2.4%. The remainder of MMPA's load is in the OTP LBA, with transmission losses of 3.1%. In October 2018, MMPA will begin serving Elk River load in the GRE LBA, which currently has transmission losses of 1.4%. For the purposes of this IRP, the Agency assumes aggregate 2.3% transmission losses.

MISO's planning reserve margin requirement is expected to be 8.4% in planning year 2018. For long term planning purposes, a planning reserve margin of 8.4% was used.

Appendix B. Advance Forecast

This appendix contains MMPA's filing to the Department of Commerce as outlined in Minnesota Administrative Rules Chapter 7610.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

The individual worksheets in this spreadsheet file correspond closely to the tables in the paper forms received by the utility.
The instructions provided with the paper forms also pertain to the data to be entered in each of the worksheets in this file.
PLEASE DO NOT CHANGE THE **NAME** OR **ORDER** OF ANY OF THE WORKSHEET TABS IN THIS FILE

In general, the following scheme is used on each worksheet:

Cells shown with a light green background correspond to headings for columns, rows or individual fields.
Cells shown with a light yellow background require data to be entered by the utility.
Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet contains a section labeled Comments below the main data entry area.
You may enter any comments in that section that may be needed to explain or clarify the data being entered on the worksheet.

Please complete the required worksheets and save the completed spreadsheet file to your local computer.
Then attach the completed spreadsheet file to an e-mail message and send it to the following e-mail address:
rule7610.reports@state.mn.us

If you have any questions please contact:

Anne Sell
MN Department of Commerce
rule7610.reports@state.mn.us
(651) 539-1851

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	266	RILS ID#	U13724
REPORT YEAR	2017		

UTILITY DETAILS	
UTILITY NAME	Minnesota Municipal Power Agency
STREET ADDRESS	220 South Sixth Street Suite 1300
CITY	Minneapolis
STATE	Minnesota
ZIP CODE	55402
TELEPHONE	(612) 349-6868
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	

CONTACT INFORMATION	
CONTACT NAME	Oncu Er
CONTACT TITLE	Sr. Vice President
CONTACT STREET ADDRESS	220 South Sixth Street Suite 1300
CITY	Minneapolis
STATE	Minnesota
ZIP CODE	55402
TELEPHONE	(612) 349-6868
CONTACT E-MAIL	Oncu.Er@AvantEnergy.com

COMMENTS

PREPARER INFORMATION	
PERSON PREPARING FORMS	Samuel Meersman
PREPARER'S TITLE	Sr. Manager
DATE	7/18/2018

ALLOWABLE UTILITY TYPES

Code

Private

Public

Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2017	No. of Cust.									0
		MWH									0
Present Year	2018	No. of Cust.									0
		MWH									0
1st Forecast Year	2019	No. of Cust.									0
		MWH									0
2nd Forecast Year	2020	No. of Cust.									0
		MWH									0
3rd Forecast Year	2021	No. of Cust.									0
		MWH									0
4th Forecast Year	2022	No. of Cust.									0
		MWH									0
5th Forecast Year	2023	No. of Cust.									0
		MWH									0
6th Forecast Year	2024	No. of Cust.									0
		MWH									0
7th Forecast Year	2025	No. of Cust.									0
		MWH									0
8th Forecast Year	2026	No. of Cust.									0
		MWH									0
9th Forecast Year	2027	No. of Cust.									0
		MWH									0
10th Forecast Year	2028	No. of Cust.									0
		MWH									0
11th Forecast Year	2029	No. of Cust.									0
		MWH									0
12th Forecast Year	2030	No. of Cust.									0
		MWH									0
13th Forecast Year	2031	No. of Cust.									0
		MWH									0
14th Forecast Year	2032	No. of Cust.									0
		MWH									0

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MMPA is requesting an exemption from this forecast page, as it sells all of its electricity to its member municipal utilities at wholesale. The Agency does not project customer count by class as part of its future energy and demand forecasts. As discussed in the Integrated Resource Plan, MMPA uses projected population of member cities to project energy and demand requirements.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. MINNESOTA-ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your Minnesota service area only, for the past year, your best estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2017	No. of Cust.									0
		MWH									0
Present Year	2018	No. of Cust.									0
		MWH									0
1st Forecast Year	2019	No. of Cust.									0
		MWH									0
2nd Forecast Year	2020	No. of Cust.									0
		MWH									0
3rd Forecast Year	2021	No. of Cust.									0
		MWH									0
4th Forecast Year	2022	No. of Cust.									0
		MWH									0
5th Forecast Year	2023	No. of Cust.									0
		MWH									0
6th Forecast Year	2024	No. of Cust.									0
		MWH									0
7th Forecast Year	2025	No. of Cust.									0
		MWH									0
8th Forecast Year	2026	No. of Cust.									0
		MWH									0
9th Forecast Year	2027	No. of Cust.									0
		MWH									0
10th Forecast Year	2028	No. of Cust.									0
		MWH									0
11th Forecast Year	2029	No. of Cust.									0
		MWH									0
12th Forecast Year	2030	No. of Cust.									0
		MWH									0
13th Forecast Year	2031	No. of Cust.									0
		MWH									0
14th Forecast Year	2032	No. of Cust.									0
		MWH									0

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MMPA is requesting an exemption from this forecast page, as it sells all of its electricity to its member municipal utilities at wholesale. The Agency does not project customer count by class as part of its future energy and demand forecasts. As discussed in the Integrated Resource Plan, MMPA uses projected population of member cities to project energy and demand requirements.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Express in MWH)

NOTE: (Column 1 + Column 2) = (Column 3 + Column 5) - (Column 4 + Column 6)

It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet.

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA in MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA in MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES in MWH [7610.0310 B(3)]	DELIVERED FOR RESALE in MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION in MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES in MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION in MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION in MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year	2017			1,515,800	2,614,667	1,098,867				0
Present Year	2018			1,645,737	2,662,829	1,017,092				0
1st Forecast Year	2019			1,925,452	2,942,544	1,017,092				0
2nd Forecast Year	2020			1,950,524	3,568,245	1,617,721				0
3rd Forecast Year	2021			1,963,088	3,579,364	1,616,276				0
4th Forecast Year	2022			1,979,777	3,596,053	1,616,276				0
5th Forecast Year	2023			1,995,207	3,611,483	1,616,276				0
6th Forecast Year	2024			2,016,234	3,633,954	1,617,721				0
7th Forecast Year	2025			2,025,785	3,642,061	1,616,276				0
8th Forecast Year	2026			2,040,921	3,657,197	1,616,276				0
9th Forecast Year	2027			2,055,635	3,671,911	1,616,276				0
10th Forecast Year	2028			2,076,571	3,694,292	1,617,721				0
11th Forecast Year	2029			2,084,796	3,701,072	1,616,276				0
12th Forecast Year	2030			2,099,060	3,714,751	1,615,691				0
13th Forecast Year	2031			2,112,665	3,728,161	1,615,496				0
14th Forecast Year	2032			2,133,062	3,750,003	1,616,941				0

COMMENTS

Under the Midwest Independent Transmission System Operator's (MISO) energy market, utilities purchase all of their load from MISO and sell all of the output from their generating resources to MISO. This table has been completed reflecting that structure of the industry. MMPA supplies its memeber cities with energy for resale. The energy values reported here correspond to a calendar year reporting period.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT THE TIME OF ANNUAL SYSTEM PEAK (in MW)

	FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day 2017									0.0

7610.0310 Item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR (in MW)

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Last Year 2017	228.4	209.4	197.4	190.9	229.1	284.9	318.7	290.8	306.8	207.3	206.0	223.5

COMMENTS
MMPA is requesting an exemption from Item C of this page, as it does not possess the information necessary to classify the system peak by class of service. The Agency sells all of its power and energy to its member utilities at wholesale. The peak demand presented in Item D includes 2.3% transmission system losses.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 1: FIRM PURCHASES (Express in MW)

		NAME OF OTHER UTILITY =>								
Past Year	2017	Summer								
		Winter								
Present Year	2018	Summer								
		Winter								
1st Forecast Year	2019	Summer								
		Winter								
2nd Forecast Year	2020	Summer								
		Winter								
3rd Forecast Year	2021	Summer								
		Winter								
4th Forecast Year	2022	Summer								
		Winter								
5th Forecast Year	2023	Summer								
		Winter								
6th Forecast Year	2024	Summer								
		Winter								
7th Forecast Year	2025	Summer								
		Winter								
8th Forecast Year	2026	Summer								
		Winter								
9th Forecast Year	2027	Summer								
		Winter								
10th Forecast Year	2028	Summer								
		Winter								
11th Forecast Year	2029	Summer								
		Winter								
12th Forecast Year	2030	Summer								
		Winter								
13th Forecast Year	2031	Summer								
		Winter								
14th Forecast Year	2032	Summer								
		Winter								

COMMENTS

The Agency Does not Have any Firm Purchases from Other Utilities

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 2: FIRM SALES (Express in MW)

		NAME OF OTHER UTILITY =>								
Past Year	2017	Summer								
		Winter								
Present Year	2018	Summer								
		Winter								
1st Forecast Year	2019	Summer								
		Winter								
2nd Forecast Year	2020	Summer								
		Winter								
3rd Forecast Year	2021	Summer								
		Winter								
4th Forecast Year	2022	Summer								
		Winter								
5th Forecast Year	2023	Summer								
		Winter								
6th Forecast Year	2024	Summer								
		Winter								
7th Forecast Year	2025	Summer								
		Winter								
8th Forecast Year	2026	Summer								
		Winter								
9th Forecast Year	2027	Summer								
		Winter								
10th Forecast Year	2028	Summer								
		Winter								
11th Forecast Year	2029	Summer								
		Winter								
12th Forecast Year	2030	Summer								
		Winter								
13th Forecast Year	2031	Summer								
		Winter								
14th Forecast Year	2032	Summer								
		Winter								

COMMENTS

The Agency Does not Have any Firm Sales to Other Utilities

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 1: PARTICIPATION PURCHASES (Express in MW)

NAME OF OTHER UTILITY =>			Short Term Capacity Purchases							
Past Year	2017	Summer	10							
		Winter	10							
Present Year	2018	Summer	5							
		Winter	5							
1st Forecast Year	2019	Summer	70							
		Winter	70							
2nd Forecast Year	2020	Summer	65							
		Winter	65							
3rd Forecast Year	2021	Summer	70							
		Winter	70							
4th Forecast Year	2022	Summer	75							
		Winter	75							
5th Forecast Year	2023	Summer	80							
		Winter	80							
6th Forecast Year	2024	Summer	85							
		Winter	85							
7th Forecast Year	2025	Summer	90							
		Winter	90							
8th Forecast Year	2026	Summer	90							
		Winter	90							
9th Forecast Year	2027	Summer	95							
		Winter	95							
10th Forecast Year	2028	Summer	100							
		Winter	100							
11th Forecast Year	2029	Summer	105							
		Winter	105							
12th Forecast Year	2030	Summer	0							
		Winter	0							
13th Forecast Year	2031	Summer	0							
		Winter	0							
14th Forecast Year	2032	Summer	0							
		Winter	0							

COMMENTS

This spreadsheet reflects transactions entered into as of 7/15/18. Short term capacity purchases from several counterparties are aggregated for limited disclosure. The data reported for each season follows MISO's planning year construct because it is according to that construct that MMPA purchases capacity. Under that construct -- and as reported here -- summer of a given planning year corresponds to June-November of that year, and winter of a given planning year corresponds to December of that year through May of the next year.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 2: PARTICIPATION SALES (Express in MW)

NAME OF OTHER UTILITY =>										
Past Year	2017	Summer								
		Winter								
Present Year	2018	Summer								
		Winter								
1st Forecast Year	2019	Summer								
		Winter								
2nd Forecast Year	2020	Summer								
		Winter								
3rd Forecast Year	2021	Summer								
		Winter								
4th Forecast Year	2022	Summer								
		Winter								
5th Forecast Year	2023	Summer								
		Winter								
6th Forecast Year	2024	Summer								
		Winter								
7th Forecast Year	2025	Summer								
		Winter								
8th Forecast Year	2026	Summer								
		Winter								
9th Forecast Year	2027	Summer								
		Winter								
10th Forecast Year	2028	Summer								
		Winter								
11th Forecast Year	2029	Summer								
		Winter								
12th Forecast Year	2030	Summer								
		Winter								
13th Forecast Year	2031	Summer								
		Winter								
14th Forecast Year	2032	Summer								
		Winter								

COMMENTS
The Agency Does not Have any Participation Sales

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item G. LOAD AND GENERATION CAPACITY (Express in MW)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2017	Summer	319		319	319			319	319	353	10		363	27	346	17
		Winter	228		228	319			228	319	353	10		363	19	248	115
Present Year	2018	Summer	330		330	330			330	330	356	5		361	28	358	3
		Winter	298		298	330			298	330	356	5		361	25	323	39
1st Forecast Year	2019	Summer	406		406	406			406	406	364	70		434	34	440	-7
		Winter	301		301	406			301	406	364	70		434	25	326	108
2nd Forecast Year	2020	Summer	410		410	410			410	410	364	65		429	34	445	-16
		Winter	303		303	410			303	410	364	65		429	25	329	100
3rd Forecast Year	2021	Summer	414		414	414			414	414	364	70		434	35	449	-15
		Winter	306		306	414			306	414	364	70		434	26	332	102
4th Forecast Year	2022	Summer	418		418	418			418	418	364	75		439	35	453	-14
		Winter	308		308	418			308	418	364	75		439	26	334	104
5th Forecast Year	2023	Summer	421		421	421			421	421	364	80		444	35	456	-13
		Winter	311		311	421			311	421	364	80		444	26	337	107
6th Forecast Year	2024	Summer	424		424	424			424	424	364	85		449	36	460	-11
		Winter	313		313	424			313	424	364	85		449	26	340	109
7th Forecast Year	2025	Summer	427		427	427			427	427	364	90		454	36	463	-10
		Winter	316		316	427			316	427	364	90		454	27	342	112
8th Forecast Year	2026	Summer	430		430	430			430	430	364	90		454	36	467	-13
		Winter	318		318	430			318	430	364	90		454	27	345	109
9th Forecast Year	2027	Summer	434		434	434			434	434	364	95		459	36	470	-11
		Winter	320		320	434			320	434	364	95		459	27	347	111
10th Forecast Year	2028	Summer	437		437	437			437	437	364	100		464	37	473	-10
		Winter	322		322	437			322	437	364	100		464	27	349	114
11th Forecast Year	2029	Summer	440		440	440			440	440	364	105		469	37	477	-8
		Winter	325		325	440			325	440	364	105		469	27	352	117
12th Forecast Year	2030	Summer	443		443	443			443	443	364	0		364	37	480	-116
		Winter	327		327	443			327	443	364	0		364	27	354	9
13th Forecast Year	2031	Summer	445		445	445			445	445	364	0		364	37	483	-119
		Winter	329		329	445			329	445	364	0		364	28	357	7
14th Forecast Year	2032	Summer	448		448	448			448	448	364	0		364	38	486	-123
		Winter	331		331	448			331	448	364	0		364	28	359	5

COMMENTS

Seasonal Demands as shown include 2.3% Transmission System Losses. Net Generating capability accounts for EFORDs. Assumption for Net Reserve Capacity Obligation is 8.4%.

The summer demand reported here for a given year corresponds to MMPA's summer peak demand of that year. The winter demand reported for a given year is MMPA's peak demand for the winter season beginning in November of that year and extending into the next year.

As requested in DOC instructions, we report MMPA's maximum seasonal demand here. In MMPA's IRP, in accordance with MISO requirements, we report MMPA's Coincident Peak (CP) with MISO at the time of MISO's annual peak. Per MISO requirements, MMPA's capacity requirements, as reported in the IRP, are based upon MMPA's CP with MISO. Therefore, the capacity obligation reported here (based upon MMPA's NCP) differs from that reported in MMPA's IRP.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MW)

		ADDITIONS	RETIREMENTS
Past Year	2017		
Present Year	2018		
1st Forecast Year	2019		
2nd Forecast Year	2020		
3rd Forecast Year	2021		
4th Forecast Year	2022		
5th Forecast Year	2023		
6th Forecast Year	2024		
7th Forecast Year	2025		
8th Forecast Year	2026		
9th Forecast Year	2027		
10th Forecast Year	2028		
11th Forecast Year	2029		
12th Forecast Year	2030		
13th Forecast Year	2031		
14th Forecast Year	2032		

COMMENTS

The Agency Does not Have any Additions and Retirments

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Please use the appropriate code for the fuel type as shown in the list at the bottom of the worksheet.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6	
		Name of Fuel	NG	Name of Fuel	FO2	Name of Fuel		Name of Fuel		Name of Fuel		Name of Fuel	
		Unit of Measure	MMBtu	Unit of Measure	MMBtu	Unit of Measure		Unit of Measure		Unit of Measure		Unit of Measure	
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2017	4,778,291	647,224	-	-								
Present Year	2018	3,996,532	548,840	19,250	2,500								
1st Forecast Year	2019	3,996,532	548,840	19,250	2,500								
2nd Forecast Year	2020	4,006,935	550,285	19,250	2,500								
3rd Forecast Year	2021	3,996,532	548,840	19,250	2,500								
4th Forecast Year	2022	3,996,532	548,840	19,250	2,500								
5th Forecast Year	2023	3,996,532	548,840	19,250	2,500								
6th Forecast Year	2024	4,006,935	550,285	19,250	2,500								
7th Forecast Year	2025	3,996,532	548,840	19,250	2,500								
8th Forecast Year	2026	3,996,532	548,840	19,250	2,500								
9th Forecast Year	2027	3,996,532	548,840	19,250	2,500								
10th Forecast Year	2028	4,006,935	550,285	19,250	2,500								
11th Forecast Year	2029	3,996,532	548,840	19,250	2,500								
12th Forecast Year	2030	3,996,532	548,840	19,250	2,500								
13th Forecast Year	2031	3,996,532	548,840	19,250	2,500								
14th Forecast Year	2032	4,006,935	550,285	19,250	2,500								

LIST OF FUEL TYPES

BIT - Bituminous Coal	LPG - Liquefied Propane Gas	HYD - Hydro (water)
COAL - Coal (general)	NG - Natural Gas	WIND - Wind
DIESEL - Diesel	NUC - Nuclear	WOOD - Wood
FO2 - Fuel Oil #2 (Mid-distillate)	REF - Refuse, Bagasse, Peat, Non-wo	SOLAR - Solar
FO6 - Fuel Oil #6 (Residual fuel oil)	STM - Steam	
LIG - Lignite	SUB - Sub-bituminous coal	

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0500 TRANSMISSION LINES

Subpart 1. **Existing transmission lines**. Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:

A. a map showing the location of each line;
B. the design voltage of each line;
C. the size and type of conductor;
D. the approximate location of d.c. terminals or a.c. substations; and
E. the approximate length of each line in Minnesota.

Subpart 2. **Transmission line additions**. Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

Subpart 3. **Transmission line retirements**. Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts that the utility plans to retire within the next 15 years.

In Use (enter X for selection)	**To Be Built** (enter X for selection)	**To Be Retired** (enter X for selection)	**DESIGN VOLTAGE**	**SIZE OF CONDUCTOR**	**TYPE OF CONDUCTOR**	**D.C. OR A.C. (specify)**	**LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS**	**INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"**	**LENGTH IN MINNESOTA (miles)**

COMMENTS
MMPA does not own, nor does it expect to own during the forecast period, any transmission lines above 200 kilovolts.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0600, item A. 24 - HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:

A table of the demand in megawatts by the hour over a 24-hour period for:

1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest

	DATE	DATE	
	7/17/17	1/4/17	<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	169	164	
0200	159	160	
0300	153	159	
0400	151	160	
0500	152	163	
0600	163	175	
0700	181	197	
0800	207	213	
0900	223	214	
1000	238	214	
1100	254	215	
1200	271	212	
1300	283	210	
1400	295	209	
1500	307	207	
1600	314	208	
1700	318	214	
1800	319	228	
1900	314	227	
2000	305	224	
2100	292	218	
2200	276	206	
2300	245	191	
2400	214	177	

COMMENTS
MMPA's reported MW include 2.3% transmission system losses.

Appendix C. Renewable Energy Standard Rate Impact Report

This appendix contains MMPA's rate impact report for complying with the Renewable Energy Standards (RES) in Minnesota Statute §216B.1691.

Rate Impact Follows the PUC Established Methodology

MMPA's RES rate impact calculations in this appendix follow the PUC established methodology.

Minnesota Statute §216B.1691 establishes a Renewable Energy Standard and requires a utility to evaluate the rate impact of the standard and file the report as an appendix in its resource plan. On January 6, 2015, the Minnesota Public Utilities Commission (PUC) issued Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat. §216B.1691 ("Order") under Docket No. E-999/CI-11-852.

Levelized Historic RES Rate Impact Was 0.25 cents/kWh

MMPA's historic RES rate impact was evaluated for the years 2005 to 2017. On an annualized basis, the RES rate impact ranged from 0.00 to 0.96 cents per kWh. The levelized RES rate impact for this time period was 0.25 cents per kWh. Full details are provided in the historic table below.

The years analyzed satisfies Order point 2A(1) directing an analysis for the period 2005 until the last reported year.

Levelized RES Rate Impact Projected to be 0.03 cents/kWh

The RES rate impact was projected for the years 2018 to 2033. On an annualized basis, the RES rate impact is projected to range from 0.64 to (0.53) cents per kWh. The levelized RES rate impact for this time period is projected to be 0.03 cents per kWh. Full details are provided in the projection table below.

The years analyzed satisfies Order point 2A(2) directing an analysis of the 15 years following the last reported year.

Includes All Generation Assets that Comply with the Renewable Energy Standard

MMPA's rate impact analysis includes all its generation assets that meet the renewable energy standard regardless of when the asset was acquired.

The resources included in the evaluation satisfy the requirement of Order point 2B.

Rate Impact Includes Direct Costs

The RES rate impact calculations include direct costs incurred to meet the RES. These costs include power purchase agreements (PPAs) from renewable resources and the capital and operating costs of owned assets. There were no transmission costs to include in the rate impact.

The direct costs included satisfy Order points 2C and 2E.

Rate Impact Includes Avoided Costs

The RES rate impact calculations include avoided energy, capacity, and emissions costs. There were no avoided transmission costs included in the rate impact.

Historically, the avoided energy costs are those associated with MMPA's PPAs and owned assets. The projected avoided energy costs are based on locational marginal prices for Minnesota Hub, escalated at inflation. The avoided capacity costs are based on the MISO Zone 1 Cost of New Entry (CONE), escalated at inflation.

The avoided regulatory cost of emissions is included and based on the June 6, 2018 PUC Order Establishing 2018 and 2019 Estimate of Future CO_2 Regulation Costs. These costs are included starting in 2025 and estimated at the midpoint of the regulatory costs, increased at inflation.

The avoided costs accounted for in the RES rate impact are in compliance with Order points 2F and 2G(2).

Rate Impact Excludes Costs for Ancillary Services and Base Load Cycling

The RES rate impact does not include the indirect costs of ancillary services or base load cycling that are a result of the increase in intermittent generation resources on the system. Based on MISO's market construct, MMPA sells all generation output to, and procures all their load from, the MISO market. MISO charges for ancillary services and base load cycling cannot be attributed to the RES resources.

This analysis meets the requirements of Order point 2D.

RES Rate Impact Summary Tables

The tables below detail the historic and projected RES rate impact. They report annualized and levelized cost impacts, satisfying Order point 2H.

MMPA RES Rate Impact – Historical (2005-2017)

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

<u>MMPA RES Rate Impact – Projected (2018-2033)</u>

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

Appendix D. Regulatory Requirements Cross Reference Index

The following table provides a cross reference index for the various regulatory requirements related to Integrated Resource Plan filings.

Statute or Rule	Description of Requirement	Location in IRP
7843.0400 Subp. 1	Include most Advance Forecast filed with DOC	Appendix B
7843.0400 Subp. 2	File a proposed plan for meeting the service needs of its customers	Sections 7 and 10
7843.0400 Subp. 3A	Describe resource options considered, including information supporting selection of proposed resources	Section 9 and 11
7843.0400 Subp. 3B	Include descriptions of the overall process and of the analytical techniques used to create resource plan from available options	Section 11
7843.0400 Subp. 3C	Include a five-year action plan	Section 10
7843.0400 Subp. 3D	Explain why the plan is in the public interest	Section 13
7843.0400 Subp. 4	Include a non-technical summary	Section 1
216B.1691 Subd. 2e	Rate impact of compliance with Renewable Energy Standard	Section 12 and Appendix C
216B.1691 Subd. 3	Description of efforts towards meeting REO/RES	Section 12
216B.2422 Subd. 2	Include a least cost plan for meeting 50% and 75% of all energy needs from new and refurbished generating facilities through a combination of conservation and renewable energy resources	Section 12
216B.2422 Subd. 2c	Narrative on utility's progress towards achieving the state greenhouse gas emission reduction goals	Section 12
216B.2422 Subd. 3	Use Commission values and other external factors including socioeconomic costs when evaluating and selecting resource options	Section 11

Appendix E. Acronyms Index

The following index provides definitions of acronyms used in this IRP.

Acronym	Definition
AC	Alternating current
BOGF	Black Oak Getty Wind Farm
BSF	Buffalo Solar Facility
CAGR	compounded annual growth rates
CDD	Cooling degree day
CIP	Conservation Improvement Program
CP	Coincident peak
DIR	Dispatchable Intermittent Resource
DOC	Department of Commerce
EFORd	Equivalent demand forced outage rate
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERMU	Elk River Municipal Utilities
FEP	Faribault Energy Park
FERC	Federal Energy Regulatory Commission
GOR	Gross operating revenue
GW	Gigawatt
GWh	Gigawatt-hour
HDD	Heating degree day
HTBE	Hometown BioEnergy
ICAP	Installed capacity
IRP	Integrated resource plan
kW	Kilowatt
kWh	Kilowatt-hour
LBA	Local balancing area
LNG	Liquified natural gas
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator
MMPA	Minnesota Municipal Power Agency

MRS	Minnesota River Station
MW	Megawatt
MWh	Megawatt-hour
NOAA	National Oceanic and Atmospheric Administration
NCP	Non-coincident peak
OGWF	Oak Glen Wind Farm
PPA	Power purchase agreement
ppb	Parts per billion
PRM	Planning reserve margin
PRMR	Planning resource margin requirements
PUC	Public Utilities Commission
PY	Planning year (June 1 through May 31)
REC	Renewable energy credit
RES	Renewable energy standard
SEP	Shakopee Energy Park
UCAP	Unforced capacity
WAPA	Western Area Power Administration
ZRC	Zonal resource credits

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July 30, 2018

VIA E-FILING
Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place E, Suite 350
Saint Paul, Minnesota 55101

Re: MMPA 2018 Resource Plan
DOCKET NO: E ______/RP-18-______

Dear Mr. Wolf:

Minnesota Municipal Power Agency (MMPA) is pleased to submit its 2018 Integrated Resource Plan (IRP) to the Minnesota Public Utilities Commission (Commission). The planning period covered in MMPA's 2018 IRP is 2019-2033.

This is MMPA's fourth IRP. The Commission accepted MMPA's 2008, 2011, and 2013 IRPs and found MMPA to be in compliance with its Renewable Energy Standards obligations. MMPA has incorporated into the current IRP the recommendations made by the Commission in approving MMPA's 2013 IRP. The Commission recommended (*italicized text*) that MMPA:

A. *Continue working with all interested parties on an alternate, statistically valid methodology to project the utility peak demand coincident with the system peak of the Midcontinent Independent System Operator, Inc. (MISO).*

MMPA utilized a coincident factor methodology for projecting utility peak demand coincident with the system peak of MISO. Details of this projection are included in Section 4 and Appendix A.

B. *Increase the estimate of its accredited resources by –*

- *taking into account a reasonable estimate of the accredited capacity of wind resources and*
- *assuming that the historical Equivalent Forced Outage Rate demand rates for its Faribault Energy Park and Minnesota River Station generation facilities continue at least through 2018.*

MMPA's capacity planning includes reasonable estimates of accredited capacity of the Agency's wind resources and assumes historical Equivalent Forced Outage Rate demand rates for Faribault Energy Park and Minnesota River Station. Details about MMPA's existing resources are included in Section 7.

C. *Participate in the dialogue with the Commission concerning whether Minnesota utilities should plan for the MISO coincident peak or non-coincident peak.*

The Agency's planning process considers both MMPA's non-coincident and coincident peak with MISO. MMPA is willing to participate in dialogue with stakeholders regarding this planning process.

D. *In its future supply-side modeling,*

- *analyze a range of possible fuel and capital costs, along with a range of environmental costs, and*
- *analyze what capacity additions best meet MMPA's needs, considering the resources currently in its portfolio.*

MMPA successfully procured long-term market capacity and is not projected to need capacity until planning year 2030. The cost of different technologies for capacity are expected to change by the time additional capacity is needed. For this reason, discussions with the Department of Commerce staff concluded that a detailed evaluation of resource alternatives is not needed for this IRP. When MMPA's capacity need becomes nearer-term, the Agency would conduct a detailed evaluation of resource alternatives. In its evaluation of resources, MMPA would consider a range of possible capital, operating, fuel, and externality costs of all resources.

E. *Continue to strive for annual energy savings of 1.5 percent.*

MMPA continues to strive to achieve energy savings averaging 1.5% of the Agency's retail sales. Section 6 of this IRP addresses Energy Conservation and Demand Side Management.

MMPA's Plan contains a discussion of how the energy industry is in transition. This transition, coupled with future economic uncertainty, necessitates planning flexibility. MMPA's Plan was designed to provide a high level of flexibility while continuing to meet member needs for a competitively-priced, reliable, and environmentally sound power supply. Overall, MMPA believes the IRP reflects the key issues facing the Agency and its members and provides a clear description of the Agency's proposed path.

Pursuant to Minn. R. 7829.3200, MMPA respectfully requests a variance from the portions of Minn. R. 7610.0310 that require a utility to provide customer count data by class. Compliance with this rule would impose an excessive burden upon MMPA because, as a wholesale supplier to its members, the Agency has no retail customers. Therefore, it does not keep this data. Moreover, granting the variance would neither adversely affect the public interest nor conflict with standards imposed by law.

Enclosed, please find the Public and Non-public versions of MMPA's 2018 Integrated Resource Plan and supporting documentation. Please contact me at (612) 252-6542 if you have any questions.

Very truly yours,

Avant Energy, Inc.
Agent for MMPA

Oncu Er

Enclosures
cc: Service List

STATEMENT JUSTIFYING IDENTIFICATION OF DATA AS TRADE SECRET

Pursuant to the Minnesota Public Utilities Commission's Revised Procedures for Handling Trade Secret and Privileged Data, data September 1, 1999 and Minn. R. 7829.0500, information designated by Minnesota Municipal Power Agency (MMPA) as "Trade Secret" in the Non-Public version of this filing meets the definition in Minn. Stat. §13.37 subd. 1(b).

Under Minn. Stat. §13.37 subd. 1(b) "Trade secret information" is defined as

> government data, including a formula, pattern, compilation, program, device, method, technique or process (1) that was supplied by the affected individual or organization, (2) that is the subject of efforts by the individual or organization that are reasonable under the circumstances to maintain its secrecy, and (3) that derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

The information designated as "Trade Secret" in the Non-Public version of this filing was supplied by MMPA, the affected organization. MMPA makes significant efforts to maintain the secrecy of certain strategic planning, resource, and other operational information. Such information is protected by MMPA as confidential and is not available to others outside the Agency. This information is economically valuable to MMPA and its customers in the form of a competitive advantage for resource planning, development, and operations. Should MMPA's competitors gain access to this information, which is not generally known or ascertainable by proper means, MMPA's competitors would erode this competitive advantage, causing MMPA and its customers to suffer.

CERTIFICATE OF SERVICE

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

I, Oncu Er, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota.

Minnesota Municipal Power Agency – 2018 IRP Filing

DOCKET NO: E ______/RP-18-______

Dated this **30th** day of **July 2018**

____
Oncu Er

CHRISTINA L HOLTAN
Notary Public
Minnesota
My Comm. Expires
Jan 31, 2020

Christina L. Holtan 7/30/18

In The Matter of
Minnesota Municipal Power Agency's
2018 Integrated Resource Plan

Initial Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes
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Charles	Zelle	charlie.zelle@state.mn.us	Department of Transportation	MN Dept of Transportation 395 John Ireland Blvd St. Paul, MN 55155	Electronic Service	No

Minnesota Municipal Power Agency
Integrated Resource Plan
WP1 - Energy and Demand Projection Summary
All Adjustments Made (1.3% CIP, WAPA, Losses, PRMR)

Year	Energy (MWh)	MMPA NCP (MW)	MMPA CP (MW)
2018	1,645,737	358.2	335.4
2019	1,925,452	440.4	412.6
2020	1,950,524	444.9	416.9
2021	1,963,088	449.0	420.7
2022	1,979,777	452.7	424.2
2023	1,995,207	456.2	427.5
2024	2,016,234	459.8	430.8
2025	2,025,785	463.2	434.0
2026	2,040,921	466.6	437.2
2027	2,055,635	469.9	440.3
2028	2,076,571	473.4	443.6
2029	2,084,796	476.5	446.6
2030	2,099,060	479.8	449.6
2031	2,112,665	482.9	452.5
2032	2,133,062	486.2	455.6
2033	2,140,227	489.1	458.3
Notes	1	2	3

Notes

1) The energy values here include adjustments for 1.3% CIP savings and WAPA allocations.

2) Peak Demand values are calculated by applying the 55.9% load factor to energy values adjusted for conservation only; the resulting numbers are then adjusted for WAPA allocations, transmission losses, and the planning reserve margin. The demand values here reflect all of those adjustments.

3) Demand values at the time of MISO's peak reflect all adjustments for conservation, WAPA allocations, transmission losses, and the planning reserve margin.

Minnesota Municipal Power Agency
Integrated Resource Plan
WP2 - Annual Energy Projections
Annual Summary

PUBLIC VERSION - TRADE SECRET DATA HAS BEEN EXCISED
ALL TRADE SECRET INFORMATION HIGHLIGHTED IN YELLOW

	Results of Base Energy Projection							No Conservation				Base Case: CIP Savings = 1.3%			Low Case: CIP Savings = 1.0%			High Case: CIP Savings = 1.5%		
	Notes		MMPA11		Elk River	MMPA12		Adjustments		Adjusted		1.3%	Adjusted		1.0%	Adjusted		1.5%	Adjusted	
Year	Cities Included	Shakopee Data	Annual Energy	Annual Growth	Annual Energy	Annual Energy	Annual Growth	Olivia WAPA	EGF WAPA	Annual Energy	Annual Growth	Cons. Adjust	Annual Energy	Annual Growth	Cons. Adjust	Annual Energy	Annual Growth	Cons. Adjust	Annual Energy	Annual Growth
1988	MMPA9	A-M	581,379			581,379		(23,362)		558,017			558,017			558,017			558,017	
1989	MMPA9	A-M	587,479	1.0%		587,479	1.0%	(23,284)		564,195	1.1%		564,195	1.1%		564,195	1.1%		564,195	1.1%
1990	MMPA9	A-M	611,311	4.1%		611,311	4.1%	(23,284)		588,027	4.2%		588,027	4.2%		588,027	4.2%		588,027	4.2%
1991	MMPA9	A-M	644,670	5.5%		644,670	5.5%	(23,284)		621,386	5.7%		621,386	5.7%		621,386	5.7%		621,386	5.7%
1992	MMPA9	A-M	664,883	3.1%		664,883	3.1%	(23,362)		641,521	3.2%		641,521	3.2%		641,521	3.2%		641,521	3.2%
1993	MMPA9	A-M	700,013	5.3%		700,013	5.3%	(23,284)		676,729	5.5%		676,729	5.5%		676,729	5.5%		676,729	5.5%
1994	MMPA9	A-M	736,619	5.2%		736,619	5.2%	(23,284)		713,335	5.4%		713,335	5.4%		713,335	5.4%		713,335	5.4%
1995	MMPA9	A-M	791,495	7.4%		791,495	7.4%	(23,284)		768,211	7.7%		768,211	7.7%		768,211	7.7%		768,211	7.7%
1996	MMPA10	A-M	962,177	21.6%		962,177	21.6%	(23,362)	(76,502)	862,313	12.2%		862,313	12.2%		862,313	12.2%		862,313	12.2%
1997	MMPA10	A-M	980,934	1.9%		980,934	1.9%	(23,284)	(76,237)	881,413	2.2%		881,413	2.2%		881,413	2.2%		881,413	2.2%
1998	MMPA10	A-M	1,019,865	4.0%		1,019,865	4.0%	(23,284)	(76,237)	920,344	4.4%		920,344	4.4%		920,344	4.4%		920,344	4.4%
1999	MMPA10	A-M	1,083,155	6.2%		1,083,155	6.2%	(23,284)	(76,237)	983,634	6.9%		983,634	6.9%		983,634	6.9%		983,634	6.9%
2000	MMPA11	A-M	1,270,613	17.3%		1,270,613	17.3%	(23,362)	(76,502)	1,170,749	19.0%		1,170,749	19.0%		1,170,749	19.0%		1,170,749	19.0%
2001	MMPA11	A-M	1,284,525	1.1%		1,284,525	1.1%	(22,351)	(73,189)	1,188,985	1.6%		1,188,985	1.6%		1,188,985	1.6%		1,188,985	1.6%
2002	MMPA11	A-M	1,305,250	1.6%		1,305,250	1.6%	(22,351)	(73,189)	1,209,710	1.7%		1,209,710	1.7%		1,209,710	1.7%		1,209,710	1.7%
2003	MMPA11	A-M	1,304,382	-0.1%		1,304,382	-0.1%	(22,351)	(73,189)	1,208,842	-0.1%		1,208,842	-0.1%		1,208,842	-0.1%		1,208,842	-0.1%
2004	MMPA11	A-M	1,324,848	1.6%		1,324,848	1.6%	(22,426)	(73,443)	1,228,979	1.7%		1,228,979	1.7%		1,228,979	1.7%		1,228,979	1.7%
2005	MMPA11	A-M	1,416,268	6.9%		1,416,268	6.9%	(22,351)	(73,189)	1,320,728	7.5%		1,320,728	7.5%		1,320,728	7.5%		1,320,728	7.5%
2006	MMPA11	A-M	1,433,662	1.2%		1,433,662	1.2%	(22,307)	(73,051)	1,338,304	1.3%		1,338,304	1.3%		1,338,304	1.3%		1,338,304	1.3%
2007	MMPA11	A-M	1,458,908	1.8%		1,458,908	1.8%	(22,307)	(73,051)	1,363,550	1.9%		1,363,550	1.9%		1,363,550	1.9%		1,363,550	1.9%
2008	MMPA11	A-M	1,428,431	-2.1%		1,428,431	-2.1%	(22,381)	(73,304)	1,332,746	-2.3%		1,332,746	-2.3%		1,332,746	-2.3%		1,332,746	-2.3%
2009	MMPA11	A-F, N	1,446,657	1.3%		1,446,657	1.3%	(22,307)	(73,051)	1,351,299	1.4%		1,351,299	1.4%		1,351,299	1.4%		1,351,299	1.4%
2010	MMPA11	A-F, N	1,515,855	4.8%		1,515,855	4.8%	(22,307)	(73,051)	1,420,497	5.1%		1,420,497	5.1%		1,420,497	5.1%		1,420,497	5.1%
2011	MMPA11	A-F, N	1,535,224	1.3%		1,535,224	1.3%	(22,307)	(73,051)	1,439,866	1.4%		1,439,866	1.4%		1,439,866	1.4%		1,439,866	1.4%
2012	MMPA11	A-F, N	1,576,673	2.7%		1,576,673	2.7%	(22,381)	(73,304)	1,480,988	2.9%		1,480,988	2.9%		1,480,988	2.9%		1,480,988	2.9%
2013	MMPA11	A-F, N	1,582,614	0.4%		1,582,614	0.4%	(22,307)	(73,051)	1,487,256	0.4%		1,487,256	0.4%		1,487,256	0.4%		1,487,256	0.4%
2014	MMPA11	A-F, N	1,590,269	0.5%		1,590,269	0.5%	(22,307)	(73,051)	1,494,911	0.5%		1,494,911	0.5%		1,494,911	0.5%		1,494,911	0.5%
2015	MMPA11	A-F, N	1,592,361	0.1%		1,592,361	0.1%	(22,307)	(73,051)	1,497,003	0.1%		1,497,003	0.1%		1,497,003	0.1%		1,497,003	0.1%
2016	MMPA11	A-F, N	1,627,673	2.2%		1,627,673	2.2%	(22,381)	(73,304)	1,531,988	2.3%		1,531,988	2.3%		1,531,988	2.3%		1,531,988	2.3%
2017	MMPA11	A-F, N	1,611,158	-1.0%		1,611,158	-1.0%	(22,307)	(73,051)	1,515,800	-1.1%		1,515,800	-1.1%		1,515,800	-1.1%		1,515,800	-1.1%
2018	MMPA12	A-F, N	1,677,298	4.1%	83,354	1,760,653	9.3%	(22,307)	(73,051)	1,665,295	9.9%	(19,558)	1,645,737	8.6%	(15,044)	1,650,250	8.9%	(22,567)	1,642,728	8.4%
2019	MMPA12	A-F, N	1,700,098	1.4%	359,957	2,060,055	17.0%	(22,307)	(73,051)	1,964,697	18.0%	(39,245)	1,925,452	17.0%	(30,188)	1,934,508	17.2%	(45,282)	1,919,414	16.8%
2020	MMPA12	A-F, N	1,727,766	1.6%	377,996	2,105,762	2.2%	(22,381)	(73,304)	2,010,077	2.3%	(59,553)	1,950,524	1.3%	(45,825)	1,964,252	1.5%	(68,700)	1,941,377	1.1%
2021	MMPA12	A-F, N	1,745,919	1.1%	394,133	2,140,052	1.6%	(22,307)	(73,051)	2,044,694	1.7%	(81,606)	1,963,088	0.6%	(62,834)	1,981,860	0.9%	(94,100)	1,950,593	0.5%
2022	MMPA12	A-F, N	1,769,019	1.3%	411,649	2,180,669	1.9%	(22,307)	(73,051)	2,085,311	2.0%	(105,533)	1,979,777	0.9%	(81,331)	2,003,980	1.1%	(121,618)	1,963,693	0.7%
2023	MMPA12	A-F, N	1,792,003	1.3%	429,398	2,221,401	1.9%	(22,307)	(73,051)	2,126,043	2.0%	(130,836)	1,995,207	0.8%	(100,933)	2,025,110	1.1%	(150,675)	1,975,368	0.6%
2024	MMPA12	A-F, N	1,819,913	1.6%	448,380	2,268,293	2.1%	(22,381)	(73,304)	2,172,608	2.2%	(156,374)	2,016,234	1.1%	(120,766)	2,051,841	1.3%	(179,953)	1,992,654	0.9%
2025	MMPA12	A-F, N	1,838,125	1.0%	465,124	2,303,249	1.5%	(22,307)	(73,051)	2,207,891	1.6%	(182,106)	2,025,785	0.5%	(140,803)	2,067,088	0.7%	(209,401)	1,998,490	0.3%
2026	MMPA12	A-F, N	1,861,195	1.3%	483,151	2,344,346	1.8%	(22,307)	(73,051)	2,248,988	1.9%	(208,067)	2,040,921	0.7%	(161,073)	2,087,916	1.0%	(239,060)	2,009,929	0.6%
2027	MMPA12	A-F, N	1,884,040	1.2%	501,182	2,385,222	1.7%	(22,307)	(73,051)	2,289,864	1.8%	(234,229)	2,055,635	0.7%	(181,553)	2,108,311	1.0%	(268,893)	2,020,971	0.5%
2028	MMPA12	A-F, N	1,912,060	1.5%	520,784	2,432,844	2.0%	(22,381)	(73,304)	2,337,159	2.1%	(260,588)	2,076,571	1.0%	(202,242)	2,134,917	1.3%	(298,898)	2,038,261	0.9%
2029	MMPA12	A-F, N	1,929,578	0.9%	537,695	2,467,272	1.4%	(22,307)	(73,051)	2,371,914	1.5%	(287,118)	2,084,796	0.4%	(223,120)	2,148,794	0.7%	(329,045)	2,042,870	0.2%
2030	MMPA12	A-F, N	1,952,189	1.2%	556,098	2,508,287	1.7%	(22,307)	(73,051)	2,412,929	1.7%	(313,869)	2,099,060	0.7%	(244,224)	2,168,705	0.9%	(359,391)	2,053,538	0.5%
2031	MMPA12	A-F, N	1,974,395	1.1%	574,437	2,548,832	1.6%	(22,307)	(73,051)	2,453,474	1.7%	(340,809)	2,112,665	0.6%	(265,531)	2,187,943	0.9%	(389,901)	2,063,573	0.5%
2032	MMPA12	A-F, N	2,002,123	1.4%	594,562	2,596,684	1.9%	(22,381)	(73,304)	2,500,999	1.9%	(367,937)	2,133,062	1.0%	(287,039)	2,213,961	1.2%	(420,574)	2,080,425	0.8%
2033	MMPA12	A-F, N	2,019,103	0.8%	611,704	2,630,808	1.3%	(22,307)	(73,051)	2,535,450	1.4%	(395,222)	2,140,227	0.3%	(308,723)	2,226,726	0.6%	(451,374)	2,084,075	0.2%

	MMPA11	MMPA12	No Conservation	Base Case	Low Case	High Case
Growth: 2000-2017	1.4%	1.4%	1.5%	1.5%	1.5%	1.5%
Growth: 2019-2033	1.2%	1.8%	1.8%	0.8%	1.0%	0.6%

Notes:
Assume 2017 CIP savings are included in 2017 load data
MMPA begins serving Elk River in October 2018

Minnesota Municipal Power Agency
Integrated Resource Plan
WP3 - NCP Projection Summary

Annual NCP include adjustments for WAPA, New Load, Transmission Losses, and Planning Reserve Margin

	Notes		Base Projection - No Adjustments				No Conservation			
			Summer		Winter		Summer		Winter	
Year	Cities Included	Shakopee Data	NCP MW	Annual Growth	NCP MW	Annual Growth	NCP MW	Annual Growth	NCP MW	Annual Growth
1988	MMPA9	A-M	141		91		151		97	
1989	MMPA9	A-M	127	-10.4%	95	3.4%	135	-10.8%	100	3.7%
1990	MMPA9	A-M	128	1.0%	101	6.5%	136	1.0%	107	6.8%
1991	MMPA9	A-M	143	11.8%	101	0.3%	153	12.2%	107	0.3%
1992	MMPA9	A-M	128	-10.1%	105	4.2%	137	-10.5%	112	4.3%
1993	MMPA9	A-M	156	21.9%	109	3.7%	168	22.7%	116	3.9%
1994	MMPA9	A-M	158	0.7%	114	4.6%	169	0.8%	122	4.8%
1995	MMPA9	A-M	182	15.2%	119	4.4%	196	15.7%	128	4.6%
1996	MMPA10	A-M	193	6.5%	151	26.7%	196	0.1%	149	16.4%
1997	MMPA10	A-M	200	3.5%	155	2.7%	205	4.5%	152	2.2%
1998	MMPA10	A-M	214	7.1%	156	0.6%	221	7.7%	153	0.7%
1999	MMPA10	A-M	232	8.2%	165	5.7%	240	8.8%	163	6.6%
2000	MMPA10	A-M	237	2.3%	179	8.3%	245	1.9%	178	9.3%
2001	MMPA10	A-M	259	9.2%	190	6.0%	270	10.2%	190	6.7%
2002	MMPA10	A-M	244	-6.0%	179	-5.7%	254	-5.9%	179	-5.9%
2003	MMPA11	A-M	275	12.9%	193	8.1%	288	13.2%	195	9.0%
2004	MMPA11	A-M	277	0.5%	205	6.1%	291	1.0%	208	6.6%
2005	MMPA11	A-M	292	5.4%	214	4.6%	306	5.2%	219	5.1%
2006	MMPA11	A-M	305	4.5%	219	2.3%	322	5.2%	224	2.5%
2007	MMPA11	A-M	292	-4.2%	216	-1.7%	308	-4.4%	220	-1.9%
2008	MMPA11	A-M	272	-6.8%	218	1.2%	285	-7.2%	223	1.3%
2009	MMPA11	A-F, N	289	6.1%	230	5.6%	302	6.0%	236	6.1%
2010	MMPA11	A-F, N	315	9.2%	235	2.0%	332	9.8%	241	2.2%
2011	MMPA11	A-F, N	335	6.3%	235	0.1%	356	7.1%	242	0.1%
2012	MMPA11	A-F, N	329	-1.9%	231	-1.8%	349	-2.0%	237	-1.9%
2013	MMPA11	A-F, N	337	2.4%	238	3.0%	356	2.2%	245	3.3%
2014	MMPA11	A-F, N	323	-4.2%	246	3.4%	341	-4.4%	254	3.7%
2015	MMPA11	A-F, N	313	-3.1%	242	-1.8%	329	-3.3%	249	-2.0%
2016	MMPA11	A-F, N	335	7.2%	239	-1.3%	354	7.6%	245	-1.4%
2017	MMPA11	A-F, N	326	-2.8%	247	3.6%	344	-2.9%	255	3.9%
2018	MMPA11	A-F, N	343	5.1%	256	3.4%	363	5.3%	264	3.7%
2019	MMPA12	A-F, N	421	22.8%	314	22.8%	449	23.9%	329	24.5%
2020	MMPA12	A-F, N	429	1.9%	320	1.9%	458	2.0%	336	2.1%
2021	MMPA12	A-F, N	437	1.9%	326	1.9%	467	2.0%	343	2.0%
2022	MMPA12	A-F, N	446	1.9%	333	1.9%	477	2.0%	350	2.0%
2023	MMPA12	A-F, N	454	1.9%	339	1.9%	486	1.9%	356	2.0%
2024	MMPA12	A-F, N	462	1.8%	345	1.8%	495	1.9%	363	1.9%
2025	MMPA12	A-F, N	471	1.8%	351	1.8%	504	1.9%	370	1.9%
2026	MMPA12	A-F, N	479	1.8%	357	1.8%	514	1.8%	377	1.9%
2027	MMPA12	A-F, N	487	1.7%	364	1.7%	523	1.8%	384	1.8%
2028	MMPA12	A-F, N	496	1.7%	370	1.7%	532	1.8%	391	1.8%
2029	MMPA12	A-F, N	504	1.7%	376	1.7%	542	1.7%	398	1.8%
2030	MMPA12	A-F, N	513	1.7%	382	1.7%	551	1.7%	405	1.7%
2031	MMPA12	A-F, N	521	1.6%	389	1.6%	560	1.7%	412	1.7%
2032	MMPA12	A-F, N	529	1.6%	395	1.6%	569	1.6%	419	1.7%
2033	MMPA12	A-F, N	538	1.6%	401	1.6%	579	1.6%	426	1.7%

	Base Case: CIP Savings = 1.3%				Low Case: CIP Savings = 1.0%				High Case: CIP Savings = 1.5%			
	Summer		Winter		Summer		Winter		Summer		Winter	
Year	NCP MW	Annual Growth	NCP MW	Annual Growth	NCP MW	Annual Growth	NCP MW	Annual Growth	NCP MW	Annual Growth	NCP MW	Annual Growth
1988	151		97		151		97		151		97	
1989	135	-10.8%	100	3.7%	135	-10.8%	100	3.7%	135	-10.8%	100	3.7%
1990	136	1.0%	107	6.8%	136	1.0%	107	6.8%	136	1.0%	107	6.8%
1991	153	12.2%	107	0.3%	153	12.2%	107	0.3%	153	12.2%	107	0.3%
1992	137	-10.5%	112	4.3%	137	-10.5%	112	4.3%	137	-10.5%	112	4.3%
1993	168	22.7%	116	3.9%	168	22.7%	116	3.9%	168	22.7%	116	3.9%
1994	169	0.8%	122	4.8%	169	0.8%	122	4.8%	169	0.8%	122	4.8%
1995	196	15.7%	128	4.6%	196	15.7%	128	4.6%	196	15.7%	128	4.6%
1996	196	0.1%	149	16.4%	196	0.1%	149	16.4%	196	0.1%	149	16.4%
1997	205	4.5%	152	2.2%	205	4.5%	152	2.2%	205	4.5%	152	2.2%
1998	221	7.7%	153	0.7%	221	7.7%	153	0.7%	221	7.7%	153	0.7%
1999	240	8.8%	163	6.6%	240	8.8%	163	6.6%	240	8.8%	163	6.6%
2000	245	1.9%	178	9.3%	245	1.9%	178	9.3%	245	1.9%	178	9.3%
2001	270	10.2%	190	6.7%	270	10.2%	190	6.7%	270	10.2%	190	6.7%
2002	254	-5.9%	179	-5.9%	254	-5.9%	179	-5.9%	254	-5.9%	179	-5.9%
2003	288	13.2%	195	9.0%	288	13.2%	195	9.0%	288	13.2%	195	9.0%
2004	291	1.0%	208	6.6%	291	1.0%	208	6.6%	291	1.0%	208	6.6%
2005	306	5.2%	219	5.1%	306	5.2%	219	5.1%	306	5.2%	219	5.1%
2006	322	5.2%	224	2.5%	322	5.2%	224	2.5%	322	5.2%	224	2.5%
2007	308	-4.4%	220	-1.9%	308	-4.4%	220	-1.9%	308	-4.4%	220	-1.9%
2008	285	-7.2%	223	1.3%	285	-7.2%	223	1.3%	285	-7.2%	223	1.3%
2009	302	6.0%	236	6.1%	302	6.0%	236	6.1%	302	6.0%	236	6.1%
2010	332	9.8%	241	2.2%	332	9.8%	241	2.2%	332	9.8%	241	2.2%
2011	356	7.1%	242	0.1%	356	7.1%	242	0.1%	356	7.1%	242	0.1%
2012	349	-2.0%	237	-1.9%	349	-2.0%	237	-1.9%	349	-2.0%	237	-1.9%
2013	356	2.2%	245	3.3%	356	2.2%	245	3.3%	356	2.2%	245	3.3%
2014	341	-4.4%	254	3.7%	341	-4.4%	254	3.7%	341	-4.4%	254	3.7%
2015	329	-3.3%	249	-2.0%	329	-3.3%	249	-2.0%	329	-3.3%	249	-2.0%
2016	354	7.6%	245	-1.4%	354	7.6%	245	-1.4%	354	7.6%	245	-1.4%
2017	344	-2.9%	255	3.9%	344	-2.9%	255	3.9%	344	-2.9%	255	3.9%
2018	358	4.1%	261	2.4%	359	4.4%	262	2.7%	358	3.9%	261	2.2%
2019	440	23.0%	323	23.5%	442	23.2%	324	23.7%	439	22.8%	322	23.4%
2020	445	1.0%	326	1.0%	448	1.3%	328	1.3%	443	0.9%	324	0.9%
2021	449	0.9%	329	0.9%	453	1.2%	332	1.2%	446	0.7%	327	0.8%
2022	453	0.8%	332	0.9%	458	1.1%	336	1.1%	449	0.7%	329	0.7%
2023	456	0.8%	334	0.8%	463	1.0%	339	1.1%	452	0.6%	331	0.6%
2024	460	0.8%	337	0.8%	468	1.0%	343	1.1%	454	0.6%	333	0.6%
2025	463	0.7%	340	0.8%	473	1.0%	346	1.0%	457	0.6%	335	0.6%
2026	467	0.7%	342	0.8%	477	1.0%	350	1.0%	460	0.6%	337	0.6%
2027	470	0.7%	345	0.7%	482	1.0%	353	1.0%	462	0.5%	339	0.6%
2028	473	0.7%	347	0.8%	487	1.0%	357	1.0%	465	0.6%	341	0.6%
2029	477	0.7%	349	0.7%	491	0.9%	360	0.9%	467	0.5%	342	0.5%
2030	480	0.7%	352	0.7%	496	0.9%	364	0.9%	469	0.5%	344	0.5%
2031	483	0.6%	354	0.7%	500	0.9%	367	0.9%	472	0.5%	346	0.5%
2032	486	0.7%	357	0.7%	504	0.9%	370	0.9%	474	0.5%	348	0.5%
2033	489	0.6%	359	0.6%	509	0.8%	373	0.9%	476	0.4%	349	0.5%

	Base Projection - No Adjustments	No Conservation	Base Case: CIP Savings = 1.3%	Low Case: CIP Savings = 1.0%	High Case: CIP Savings = 1.5%
Growth: 2003-2017	1.2%	1.3%	1.3%	1.3%	1.3%
Growth: 2019-2033	1.8%	1.8%	0.8%	1.0%	0.6%

Notes:

Assume 2017 CIP savings are included in 2017 load data

MMPA begins serving Elk River in October 2018; however, do not include in NCP analysis because Oct-Dec 2018 Elk River energy will not affect Summer NCP

MMPA11 Data Before 2003 Does Not Include Buffalo Load.

(Although monthly Buffalo data pre-2003 is available, hourly Buffalo data n/a pre-2003, and hourly data must be available to pull for the hour of peak demand)

Minnesota Municipal Power Agency
Integrated Resource Plan
WP4 - CP Projection Summary

	Notes		Annual CP include adjustments for WAPA, New Load, Transmission Losses, and Planning Reserve Margin					
			Base Case: CIP Savings = 1.3%		Low Case: CIP Savings = 1.0%		High Case: CIP Savings = 1.5%	
Year	Cities Included	Shakopee Data	CP MW	Annual Growth	CP MW	Annual Growth	CP MW	Annual Growth
2005	MMPA11	A-F, N	282.8		282.8		282.8	
2006	MMPA11	A-F, N	337.7	19.4%	337.7	19.4%	337.7	19.4%
2007	MMPA11	A-F, N	284.0	-15.9%	284.0	-15.9%	284.0	-15.9%
2008	MMPA11	A-F, N	307.5	8.3%	307.5	8.3%	307.5	8.3%
2009	MMPA11	A-F, N	282.1	-8.3%	282.1	-8.3%	282.1	-8.3%
2010	MMPA11	A-F, N	303.8	7.7%	303.8	7.7%	303.8	7.7%
2011	MMPA11	A-F, N	354.9	16.8%	354.9	16.8%	354.9	16.8%
2012	MMPA11	A-F, N	336.6	-5.2%	336.6	-5.2%	336.6	-5.2%
2013	MMPA11	A-F, N	342.6	1.8%	342.6	1.8%	342.6	1.8%
2014	MMPA11	A-F, N	298.5	-12.9%	298.5	-12.9%	298.5	-12.9%
2015	MMPA11	A-F, N	302.8	1.5%	302.8	1.5%	302.8	1.5%
2016	MMPA11	A-F, N	350.8	15.8%	350.8	15.8%	350.8	15.8%
2017	MMPA11	A-F, N	323.6	-7.7%	323.6	-7.7%	323.6	-7.7%
2018	MMPA11	A-F, N	335.4	3.7%	336.4	3.9%	334.8	3.5%
2019	MMPA12	A-F, N	412.6	23.0%	414.6	23.2%	411.4	22.9%
2020	MMPA12	A-F, N	416.9	1.0%	419.8	1.3%	414.9	0.9%
2021	MMPA12	A-F, N	420.7	0.9%	424.6	1.2%	418.0	0.7%
2022	MMPA12	A-F, N	424.2	0.8%	429.4	1.1%	420.8	0.7%
2023	MMPA12	A-F, N	427.5	0.8%	433.9	1.0%	423.3	0.6%
2024	MMPA12	A-F, N	430.8	0.8%	438.4	1.0%	425.8	0.6%
2025	MMPA12	A-F, N	434.0	0.7%	442.8	1.0%	428.2	0.6%
2026	MMPA12	A-F, N	437.2	0.7%	447.2	1.0%	430.6	0.6%
2027	MMPA12	A-F, N	440.3	0.7%	451.6	1.0%	433.0	0.5%
2028	MMPA12	A-F, N	443.6	0.7%	456.0	1.0%	435.5	0.6%
2029	MMPA12	A-F, N	446.6	0.7%	460.2	0.9%	437.6	0.5%
2030	MMPA12	A-F, N	449.6	0.7%	464.4	0.9%	439.9	0.5%
2031	MMPA12	A-F, N	452.5	0.6%	468.5	0.9%	442.0	0.5%
2032	MMPA12	A-F, N	455.6	0.7%	472.8	0.9%	444.4	0.5%
2033	MMPA12	A-F, N	458.3	0.6%	476.8	0.8%	446.4	0.4%
	Growth: 2005-2016			**2.0%**		**2.0%**		**2.0%**
	Growth: 2019-2033			**0.8%**		**1.0%**		**0.6%**

Notes:
Assume 2017 CIP savings are included in 2017 load data
MMPA begins serving Elk River in October 2018; however, do not include in NCP analysis because Oct-Dec 2018 Elk River energy will not affect Summer NCP

Minnesota Municipal Power Agency
Integrated Resource Plan
WP5a - CIP Savings -- Base Case

2% Dist; 5% Trans.

Base Case: CIP Savings = 1.3%

Year	W/N Annual Wholesale Energy, MWh	Wholesale to Retail Adjustment	Retail Energy, MWh	Three-Year Rolling Average	CIP Savings Req.	Cumulative Effect	Retail to Wholesale Adjustment
2009	1,366,035	-7.1%	1,269,046				
2010	1,398,126	-7.1%	1,298,859				
2011	1,407,369	-7.1%	1,307,446	1,291,784			
2012	1,450,018	-7.1%	1,347,067	1,317,791			
2013	1,454,454	-7.1%	1,351,188	1,335,234			
2014	1,488,092	-7.1%	1,382,438	1,360,231			
2015	1,502,364	-7.1%	1,395,696	1,376,441			
2016	1,522,864	-7.1%	1,414,741	1,397,625			
2017	1,517,924	-7.1%	1,410,152	1,406,863			
2018	1,665,295	-7.1%	1,528,890	1,451,261	(18,169)	(18,169)	(19,558)
2019	1,964,697	-7.1%	1,788,745	1,575,929	(18,289)	(36,458)	(39,245)
2020	2,010,077	-7.1%	1,812,037	1,709,890	(18,866)	(55,325)	(59,553)
2021	2,044,694	-7.1%	1,823,709	1,808,163	(20,487)	(75,812)	(81,606)
2022	2,085,311	-7.1%	1,839,213	1,824,986	(22,229)	(98,040)	(105,533)
2023	2,126,043	-7.1%	1,853,547	1,838,823	(23,506)	(121,547)	(130,836)
2024	2,172,608	-7.1%	1,873,081	1,855,280	(23,725)	(145,271)	(156,374)
2025	2,207,891	-7.1%	1,881,955	1,869,528	(23,905)	(169,176)	(182,106)
2026	2,248,988	-7.1%	1,896,016	1,883,684	(24,119)	(193,295)	(208,067)
2027	2,289,864	-7.1%	1,909,685	1,895,885	(24,304)	(217,599)	(234,229)
2028	2,337,159	-7.1%	1,929,134	1,911,612	(24,488)	(242,086)	(260,588)
2029	2,371,914	-7.1%	1,936,776	1,925,198	(24,647)	(266,733)	(287,118)
2030	2,412,929	-7.1%	1,950,027	1,938,646	(24,851)	(291,584)	(313,869)
2031	2,453,474	-7.1%	1,962,666	1,949,823	(25,028)	(316,611)	(340,809)
2032	2,500,999	-7.1%	1,981,614	1,964,769	(25,202)	(341,814)	(367,937)
2033	2,535,450	-7.1%	1,988,271	1,977,517	(25,348)	(367,162)	(395,222)

Notes:
Assume 2017 CIP savings are included in 2017 load data
2018 CIP Savings Requirement is based on average of 2014-2016
Following years, follow same pattern as 2018, with the three year average rolling forward each year.
Elk River joins MMPA in October 2018
W/N Energy excludes WAPA allocation

Minnesota Municipal Power Agency
Integrated Resource Plan
WP6 - W-N Load Factor
Weather Normalization (including WAPA)

W-N Load Factor	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	5 Yr. Avg.	7 Yr. Avg.	10 Yr. Avg.
Annual Load Factor	56.4%	55.7%	55.5%	56.5%	55.1%	55.5%	54.8%	55.0%	56.5%	57.5%	55.9%	55.8%	56.1%	55.9%	55.8%
Winter Load Factor	73.8%	75.6%	73.4%	69.5%	72.6%	72.9%	76.2%	74.3%	73.4%	75.5%	77.2%	74.5%	75.0%	74.9%	74.0%
Summer Load Factor	56.4%	55.7%	55.5%	56.5%	55.1%	55.5%	54.8%	55.0%	56.5%	57.5%	55.9%	55.8%	56.1%	55.9%	55.8%
W-N Energy, MWh															
Annual	1,482,923	1,505,720	1,501,795	1,461,393	1,493,484	1,502,727	1,545,703	1,549,812	1,583,450	1,597,722	1,618,549	1,613,282			
W-N NCP Demand, MW															
Annual	300.3	308.5	307.8	295.3	309.3	309.3	320.9	321.4	319.7	317.4	329.8	330.0			
Winter	229.3	227.4	232.8	240.0	234.9	235.2	231.0	238.1	246.2	241.7	238.6	247.3			
Summer	300.3	308.5	307.8	295.3	309.3	309.3	320.9	321.4	319.7	317.4	329.8	330.0			
Hour Quantities															
Annual	8,760	8,760	8,784	8,760	8,760	8,760	8,784	8,760	8,760	8,760	8,784	8,760			

Notes:
Pre-2009 W-N energy and demand values are adjusted to include the full Shakopee load (A-N, F meters) in order to be consistent throughout the years over which the W/N load factors are calculated.

Minnesota Municipal Power Agency
Integrated Resource Plan
WP7a - MMPA Population Summary

PUBLIC VERSION - TRADE SECRET DATA HAS BEEN EXCISED
ALL TRADE SECRET INFORMATION HIGHLIGHTED IN YELLOW

Year	MMPA9	Buffalo	EGF	Elk River
1988				
1989				
1990				
1991				
1992				
1993				
1994				
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1996				
1997				
1998				
1999				
2000				
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2029				
2030				
2031				
2032				
2033				

MMPA9	Buffalo	EGF	Elk River	
				CAGR for 2000-2017

MMPA9	Buffalo	EGF	Elk River	
				CAGR for 2018-2033

Notes:

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

The individual worksheets in this spreadsheet file correspond closely to the tables in the paper forms received by the utility.
The instructions provided with the paper forms also pertain to the data to be entered in each of the worksheets in this file.
PLEASE DO NOT CHANGE THE **NAME** OR **ORDER** OF ANY OF THE WORKSHEET TABS IN THIS FILE

In general, the following scheme is used on each worksheet:

- Cells shown with a light green background correspond to headings for columns, rows or individual fields.
- Cells shown with a light yellow background require data to be entered by the utility.
- Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet contains a section labeled Comments below the main data entry area.
You may enter any comments in that section that may be needed to explain or clarify the data being entered on the worksheet.

Please complete the required worksheets and save the completed spreadsheet file to your local computer.
Then attach the completed spreadsheet file to an e-mail message and send it to the following e-mail address:
rule7610.reports@state.mn.us

If you have any questions please contact:

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