BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

STATE OF MINNESOTA

In the Matter of the Request by Minnesota Power

For a Certificate of Need for the

Great Northern Transmission Line

OAH Docket No. 65-2500-31196

MPUC Docket No. E-015/CN-12-1163

Exhibit _______

PROJECT NEED AND ALTERNATIVES

Direct Testimony and Exhibits of

ALLAN S. RUDECK, JR.

August 8, 2014

MR. ALLAN S. RUDECK, JR.

OAH Docket No. 65-2500-31196

MPUC Docket No. E-015/CN-12-1163

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I. INTRODUCTION

Q. Please state your name and business address.

A. I am Allan S. Rudeck Jr. and my business address is 30 West Superior Street, Duluth, Minnesota 55802.

Q. Please describe your educational background and work experience with ALLETE, Inc. and Minnesota Power.

A. I hold a Bachelor's Degree in Chemical Engineering from the University of Minnesota, Duluth and am a licensed, professional engineer in the State of Minnesota.

I have been employed at Minnesota Power since 1996. My service to Minnesota Power began as an engineer in the corporate engineering group. Between 1998 and 2000, I additionally supervised mechanical, electrical and instrumentation departments at our Laskin Energy Center. In 2000, I became a thermal business unit manager for the Laskin facility. In 2004, I was promoted to Manager of Engineering Services in Minnesota Power's corporate engineering department, where I led a team that provided engineering construction and quality assurance work across Minnesota Power, largely serving business needs in our transmission, thermal generation and hydroelectric generation facilities and worked to develop generation-wide environmental compliance strategies. In December 2006, I was promoted to Vice President – Generation. In 2012, I accepted responsibility as Vice President – Strategy and Planning, a role I continue to serve in today.

Q. What are your present duties as Vice President of Strategy and Planning?

A. I have overall leadership responsibilities for load forecasting, long term power supply planning (resource planning), new energy project development such as wind, hydro, natural gas, solar and coal energy conversion facilities, research and development of new power supply technology applications along with fuel sourcing (procurement and delivery) for coal, natural gas, biomass. I provide executive sponsorship of major capital projects, specifically and currently our Bison wind and Boswell environmental improvement projects. I continue in my role in providing governance oversight at Square Butte via the Joint Operating Committee with Minnkota Power.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony discusses the overall need for the Great Northern Transmission Line (also "Project") in order for Minnesota Power to continue meeting the needs of our customers for affordable, reliable and sustainable electricity. I will discuss the major factors supporting the need for the Project, not just from the perspective of Minnesota Power and its customers, but from the perspective of the State and region as well. In addition, I will discuss the adverse impact on Minnesota Power, our customers, the State and the region if the Certificate of Need is denied.

Finally, I discuss the generation, conservation and demand side management alternatives to the Project that Minnesota Power considered and explain why those do not provide a more reasonable and prudent alternative for meeting the needs identified.

Q. Do you also sponsor certain sections of Minnesota Power's Certificate of Need Application?

A. Yes, I sponsor the following portions of the Company's Certificate of Need Application ("Application"):

- Section 2 (Need Summary);
- Section 6 (Project Need);
- Sections 7.3 (Generation Alternatives);
- Section 7.5.1 (Conservation and Demand Side Management);
- Appendix H (Minnesota Power 2013 Advanced Forecast Report);
- Appendix J (Minnesota Power 2013 Resource Plan, Docket No. E-015/RP-13-53, Initial Filing, March 1, 2013); and
- Appendix K (Minnesota Power CIP Triennial Filing, Docket No. E-015/CIP-13-409, Executive Summary, June 3, 2013).

Q. Are you sponsoring any additional exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

- Exhibit ___ (AJR), Schedule 1 – Minnesota Power 2014 Advanced Forecast Report; and
- Exhibit ___ (AJR), Schedule 2 – 133 MW Renewable Optimization Agreements. Please note that this Exhibit contains TRADE SECRET information. Therefore, both a NON-PUBLIC and a PUBLIC version of this Exhibit will be filed.

II. PROJECT NEED

A. Minnesota Power's Resource Needs

1. Minnesota Power's Energy*Forward* Strategy

Q. Before turning specifically to the Company's resource needs, please discuss Minnesota Power's Energy*Forward* resource strategy and how the Project fits within that strategy and the Company's overall resource planning goals and efforts.

A. **Energy*Forward*** is Minnesota Power's road map designed to diversify Minnesota Power's once coal-dominant power supply to a more diverse, flexible and efficient power supply with less emissions including carbon while protecting affordability, and preserving reliable electric service our customers expect and deserve. As recently as 2005, Minnesota Power's supply portfolio consisted of approximately 95 percent coal fired generation. The Company has made substantial progress in rebalancing its supply portfolio, which will comprise a mix of about 25 percent renewable energy by the end of 2014. Moreover, **Energy*Forward*** calls for our portfolio to move to a balanced supply of one-third renewable energy, one-third natural gas and one-third coal – all while ensuring that the Company meets three key goals: preserving reliability, improving environmental performance and protecting affordability. Many efforts will help us achieve these goals, but two are particularly relevant to this proceeding - Minnesota Power's substantial investments in wind energy resources and the construction of the Great Northern Transmission Line, enabling Minnesota Power to take delivery of carbon-free Manitoba Hydro hydropower under agreements that also maximize the value of our wind energy assets.

Q. Can you explain the important role that renewable energy has played and will play in Minnesota Power's power supply?

A. Our **Energy*Forward*** resource strategy calls for a future power supply that is comprised of approximately one third coal, one third natural gas and one third renewables. The renewable component of Minnesota Power's **Energy*Forward*** strategy will come from four primary sources – wind, water, wood and wavelength (i.e., solar). Each is discussed below in chronological order of their development, each of which has been developed for Minnesota Power customers as they have become economically and technologically viable and commercially available.

Minnesota Power was founded as a hydroelectric generating sourced utility at the turn of the last century and was 100 percent hydroelectric power until the early 1930's. Early company pioneers harnessed northeast Minnesota's hydroelectric generating potential, creating over 110 MW of local hydroelectric generation still in operation today. However, the vast majority of Minnesota's natural hydraulic energy generating capability has already been developed, leaving no significant undeveloped hydropower resources remaining.

Additional Minnesota-based renewable energy is generated at three biomass-combined heat and power facilities located adjacent or within large paper mill customer sites in Grand Rapids, Cloquet and Duluth. Minnesota Power is exploring options to add solar energy resources to its renewable element of **Energy*Forward***.

In addition to these hydroelectric and biomass electric generating resources, Minnesota Power established among the first community–based renewable wind energy projects in Minnesota with a single wind turbine power purchase agreement, known as Wing River in 2005. This wind addition was followed by entering into two long term wind power purchases agreements, representing about 100 MW of high capacity factor North Dakota wind, at Oliver 1 and Oliver 2, located north of Center, North Dakota, owned and operated by NextEra Energy. In 2008, Minnesota Power constructed its first wind generating facility co-located at Minnesota Power's largest large power customer site, at United States Steel's Minntac Mine, located in Mountain Iron, Minnesota. This 25 MW Taconite Ridge Wind Energy Center is comprised of ten 2.5 MW wind turbines.

Between 2009 and 2012, Minnesota Power constructed 101 Siemens 2.3 and 3.0 MW wind turbines, representing an additional 292 MW of wind generation, associated 230 KV transmission and substation facilities connected to the Square Butte facility, and a 50 MW upgrade of the DC line. In 2013, construction began on Minnesota Power's largest wind facility to date. Bison 4, at about 205 MW in size, is comprised of 64 3.2 MW Siemens wind turbines plus 11 miles of additional 230 KV transmission line and a second substation. In total, Bison Wind will be comprised of 165 wind turbines, representing approximately 500 MW of wind generation, and will be the largest wind production facility in the state of North Dakota. Bison and Oliver County 1-2, together representing approximately 600 MW, are served by a strategic direct current line that extends from Center, North Dakota at the Square Butte substation to just outside Duluth, Minnesota, which was purchased by Minnesota Power in 2009 from Square Butte.

Also in 2012, the Commission approved Minnesota Power's next long term base load power supply, a 250 MW Power Purchase Agreement ("PPA") and innovative Energy Exchange Agreement with Manitoba Hydro (collectively, the "250 MW Agreements") designed to optimize wind energy together with

Manitoba Hydro hydroelectric generation, together bringing economic benefits to Minnesota Power customers. This additional, new source of carbon-free energy, and associated wind storage benefits, can only be realized by Minnesota Power, and provided by Manitoba Hydro, with the addition of a new, large transmission interconnect between the Province of Manitoba and the State of Minnesota.

Q. Can you discuss the complimentary nature of wind and hydropower in the Energy*Forward* resource strategy?

A. In addition to Minnesota Power's current wood, wind and hydropower resource portfolio, given the lack of further significant hydroelectric potential in Minnesota, Manitoba Hydro hydropower is a key component of our overall **Energy*Forward*** resource strategy. Through our 250 MW Power Purchase Agreement ("PPA") and Energy Exchange Agreement with Manitoba Hydro (collectively, the "250 MW Agreements") and the more recently developed 133 MW Energy Sale Agreement and Energy Exchange Agreement, which is introduced and discussed later, (collectively, the "133 MW Renewable Optimization Agreements," together with the 250 MW Agreements, the "Manitoba Hydro Agreements"), Minnesota Power is adding significant emission-free resources to our supply portfolio. In addition, we are optimizing the value wind and hydroelectric generating resources, providing substantial benefits to the environment, advancing public policy goals of the State of Minnesota, as outlined by Mr. McMillan and providing economic benefits for our customers and the region. I discuss the wind-hydro synergy benefits further in my testimony below.

Q. Is the Energy*Forward* resource strategy consistent with recent State and federal regulatory efforts regarding energy policy?

A. Yes it is. Minnesota Power understands that substantial efforts such as transforming our energy supply portfolio can only happen by working cooperatively with all stakeholders. Minnesota Power's overall **Energy*Forward*** strategy, including this Project, is fully consistent with the direction we see coming from State and federal regulators to diversify the generation resource mix in the State and lessen the reliance on coal fired generation.

2. The Need for Additional Capacity and Energy

Q. Along with working to diversify the Company's resource mix, has Minnesota Power identified the need for additional capacity and energy going forward?

A. Yes. Our Integrated Resource Plans ("IRP") and Advanced Forecasts consistently show the need for additional capacity and energy in the future.

Beginning with Minnesota Power's 2010 Integrated Resource Plan ("IRP") docket, MPUC Docket No. E-015/RP-09-1088 ("1088 Docket"), Minnesota Power identified significant capacity and energy needs in the 2020 to 2035 time frame driven by customer load growth and diversification of its power supply. To address these load and supply changes, the Company included action in its 2010

IRP with the intent to pursue a 250 MW Power Purchase Agreement ("PPA") with Manitoba Hydro and associated new transmission to deliver that power, with power deliveries beginning in the 2020 timeframe. The inclusion of the Manitoba hydropower and new transmission, now the Great Northern Transmission Line, to deliver that power was part of the Company's least cost system-wide long term supply plan. The Minnesota Public Utilities Commission ("Commission") accepted the Company's 2010 IRP in 2011. Subsequently submitted Advanced Forecast Reports continue to support customer load growth outlook and the need for capacity and energy delivered by the Project.

Q. You also referred to Minnesota Power's Advanced Forecast Reports as support for the need for additional capacity and energy going forward. Can you elaborate?

A. Yes. Minnesota Power's need for the additional capacity and energy to be delivered pursuant to the Manitoba Hydro Agreements is further demonstrated by Minnesota Power's 2013 Advanced Forecast Report ("AFR"), attached as Appendix H to the Application, and our 2014 AFR, attached here as Ex. ___ (AJR), Schedule 1. Given Minnesota Power's industrial load concentration, the AFRs include multiple industrial load growth scenarios. The Moderate Growth scenario in both the 2013 and 2014 AFR submittals provide the most relevant information for the purpose of this Application. Given the anticipated new load in

Minnesota Power's service territory being projected for the 2020 time period, the AFR process continues to support Minnesota Power's need for the additional capacity and energy to be purchased from Manitoba Hydro. Additionally, the key generation transformation taking place as part of our **Energy*Forward*** strategy supports the additional capacity and energy from Manitoba Hydro which includes reducing reliance on our smallest, least efficient coal resources, such as the retirement of Taconite Harbor 3 (75 MW), the gas conversion of Laskin 1-2 (110 MW), and the phased reduction in the power purchases from the Square Butte Young 2 generator (moving from 227 MW in 2013 to 100 MW by 2020 and to zero MW by 2026). The combination of customer growth and supply side transformation demonstrates Minnesota Power's need for the hydroelectric energy and capacity in the 250 MW Agreements, and the 133 Renewable Optimization Agreements, as a critical element of its long term resource strategy.

Q. Can you provide further discussion of why the Moderate Growth energy and demand scenario is most relevant and how that scenario further demonstrates the need for the Manitoba Hydro Agreements and this Project?

A. As part of its annual AFR forecasting process, Minnesota Power creates several scenarios for future customer demand and energy requirements (See Schedule 1, AFR page 44). All scenarios assume some direct load additions and/or losses from specific industrial customers, served directly by Minnesota Power or through a wholesale customer. These scenarios are utilized for utility resource and customer planning on an ongoing basis. Of the six scenarios created in the AFR process, the Moderate Growth outlook best represents what Minnesota Power must actively plan for in order to be prepared to serve those customers with a reliable and affordable power supply.

The final forecast created under each AFR scenario is the product of a robust econometric modeling process and careful consideration of potential industrial and resale customer load developments. The Moderate Growth scenario includes changes in customer operations that have a high likelihood of occurring. This high likelihood is characterized by formal communication from the customer to Minnesota Power, for the need of electricity plus one or more of the following: a) an Electric Service Agreement is either executed or is in negotiation; b) the change in operation is supported by customer actions, such as construction or investment that will result in additional power requirements; and/or c) a timeframe for the operation and resulting power changes is expected.

Based on the Moderate Growth scenario criteria above, and the customer activity underway in northeastern Minnesota, there is additional load from a number of new and existing customers underway that creates robust customer load growth between now and 2020. The scenario assumes a moderate, or “expected,” rate of national economic growth as the basis for the regional economic model and results in average annual energy sales growth and average annual peak demand growth of 1.1 percent and 1.1 percent, respectively, from 2014 through 2028, *after* incorporating an expected and sustained energy conservation offset of eligible electric retail sales of at least 1.5 percent annually. With customer energy and demand growth at these levels, Minnesota Power will reach approximately 2,000 MW of demand by the 2020 timeframe.

Q. Does Minnesota Power's most recent IRP also support the need for the Project?

A. Yes. The Company's 2013 IRP, MPUC Docket No. E-015/RP-13-53, was approved by the Commission in November of 2013. That IRP included the Project in all scenarios evaluated, including the Company's least cost system-wide supply plan. This Project and its associated agreements are a pillar of our long term resource strategy.

The 2013 IRP represented a significant step in Minnesota Power's **Energy*Forward*** resource strategy. This strategy is reshaping the Company's power supply from a predominantly coal-based energy mix to a diverse supply that minimizes customer costs, retains reliability, allows the Company to meet applicable air quality regulations in an economically and environmentally beneficial manner, and minimizes risks associated with potential further State or federal regulations that may restrict carbon emissions or penalize generators of those emissions. The diversification is already well underway with much of the progress attributed to the successful implementation of the Company's renewable energy plan, including the Bison wind farms, as well as the Manitoba Hydro Agreements and decisions made on thermal fleet transformation, including declining Square Butte off-take, retirement of Taconite Harbor Unit 3, and refueling of Laskin Units 1 and 2 from coal to natural gas. The combination of load growth outlooks and supply changes demonstrate the need for the carbon-free energy and capacity that the Project and associated agreements will deliver.

3. The Manitoba Hydro Agreements

Q. You have discussed the 250 MW Agreements between Minnesota Power and Manitoba Hydro. Did Minnesota Power already bring those Agreements to the Commission for approval?

A. Yes. Minnesota Power filed for approval of the 250 MW Agreements in MPUC Docket No. E-015/M-11-938 ("938 Docket") – between the Commission's consideration of our two most recent resource plans. In the 938 Docket, the Minnesota Department of Commerce ("Department") and Commission affirmed that Minnesota Power "will need a significant amount of capacity and energy" in the 2020-2035 time frame. Importantly, the Department and Commission also affirmed that the 250 MW Agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" over this time period.[1]

Q. In addition to the 250 MW Agreements, why has Minnesota Power also entered into the 133 MW Renewable Optimization Agreements with Manitoba Hydro?

A. From my perspective as Vice President – Strategy and Planning, the 133 MW Renewable Optimization Agreements advance the goals the Company has set forth in its **Energy*Forward*** strategy, while further optimizing the value to Minnesota Power and our customers of our substantial investments in wind energy. Together, the Manitoba Hydro Agreements and the Project allow Minnesota Power and our customers to benefit from a unique resource arrangement.

First, the 133 MW Renewable Optimization Agreements brings 230,000 MWh of additional annual carbon-free energy to Minnesota Power customers when the Manitoba Hydro electric system is surplus. This energy comes complete with environmental attributes and utilize available transmission made possible by the Project.

Also, under the 133 MW Renewable Optimization Agreements, upon completion of the Project, Minnesota Power would schedule additional energy from the Company's wind-generating facilities to Manitoba Hydro when wind production is

[1] *See* Appendix C to the Application for Department Comments and Commission Order in the 938 Docket, approving the 250 MW Agreements.

high and is not needed for customer load; during a typical year, this occurs in the evening or nighttime hours or otherwise known as off-peak time periods. When using Minnesota Power's wind power for their customer load, Manitoba Hydro would be able to temporarily reduce their hydropower generation by decreasing the flow of water through their hydropower plants. The water stored during that process would be used later to generate electricity to schedule to Minnesota when wind energy production is low or customer needs are high; during a typical year this occurs during daytime hours or otherwise known as on-peak time periods. This arrangement optimizes the use of both wind-generated energy and hydropower, which brings benefits to customers and allows us to further enhance the carbon-free portion of our long term supply portfolio. The delivery of energy drives the need for the Project. Mr. McMillan also discusses some of the factors which make the 133 MW Renewable Optimization Agreements, attached here as Ex. __ (AJR), Schedule 2, a unique and beneficial opportunity from Minnesota Power's perspective.

Q. Can you expand on the benefits that Minnesota Power's customers will see as a result of the 133 MW Renewable Optimization Agreements?

A. Yes. In addition to the resource optimization and resource diversification benefits, the 133 MW Renewable Optimization Agreements bring substantial economic benefits to our customers in several ways. First, the Renewable Optimization

Agreements includes an additional 750,000 MWh of annual "wind storage credit." As described by Mr. McMillan, the total wind storage credit benefit between the 250 MW agreements and the Renewable Optimization agreement is 1 million MWh each year, equivalent to approximately the anticipated annual off-peak production of our Bison wind generating facilities. Minnesota Power projects the economic benefits for customers of the wind storage provision from the 133 MW Renewable Optimization Agreement to be approximately $1.7 million annually, and could rise to $4 million annually should certain market conditions develop under terms of the agreement.

Second, the Renewable Optimization Agreement entitles Minnesota Power to take 230,000 MWh annually of surplus energy and associated environmental attributes. This energy is priced at market, and includes one environmental attribute with each megawatt-hour transacted. The energy is priced at market, providing optionality for Minnesota Power to either take the energy if needed for least cost customer supply, or resell to the market. In either case, Minnesota Power receives the environmental attributes as part of the transaction under the agreements. While it is difficult to place a value on these attributes at this time, the trends in North American energy policy would suggest the value will grow over time. For example, if the environmental attributes were valued at an illustrative renewable energy credit of $5 dollars per credit, the annual value to customers would be

$1.15 million. If a $20 renewable energy credit was the value basis, these environmental attributes would have an annual credit to customers of $4.6 million. Under certain contract provisions of the agreement, additional environmental attributes may be issued to Minnesota Power. For example, if the value or number of the environmental attributes doubles in these illustrations, the annual customer value to customers would be $2.3 million or $9.2 million, respectively.

Next, the 133 MW Energy Sale Agreement contains a "Monthly Must Take Fee" to offset the transmission costs associated with 133 MW portion of the Project for Minnesota Power customers whereby Manitoba Hydro will make monthly payments to Minnesota Power during the entire term of the agreement. The "Monthly Must Take Fee" will provide Minnesota Power's customers a revenue credit that includes all components of the transmission revenue requirements associated with this 133 MW portion of the Project.

The final, and very significant, benefit of the Project and associated agreements with Manitoba Hydro is the fact that Minnesota Power's 250 MW Agreements and 133 Renewable Optimization Agreements will be delivered along with other energy sales contemplated by Manitoba Hydro. The Project size at 500 kV delivers superior capital cost economy of scale for customers, as compared to a smaller 230 kV line. As outlined by Mr. Donahue in greater detail, our customer capital cost responsibility related to the Project has decreased from 33 percent to

28.3 percent of the capital investment, resulting in a revised capital cost range of $158 to $201 million, which is lower than the transmission estimate contemplated as part of the original 250 MW PPAs. The 133 MW Renewable Optimization Agreement brings together with a 500 kV Project solution a tremendous, unparalleled opportunity for our customers.

Q. Why can't Minnesota Power and its customers reap the benefits of these Agreements without building the Project?

A. As Mr. Winter and others will discuss in more detail, the current transmission system simply cannot support these Manitoba Hydro Agreements. In fact, both the Department and the Commission recognized the need for additional transmission capacity to facilitate energy trade between Manitoba and the United States in the 938 Docket. There, the agencies stated that both Manitoba Hydro and Minnesota Power "must construct their own new transmission facilities (in Canada and the USA respectively) to allow [Manitoba Hydro] to sell the contracted power" to the Company. Given this recognized need for new transmission facilities, the Commission required Minnesota Power to file reports on various significant milestones achieved regarding both the new hydroelectric generating stations being built in Manitoba and on the new major transmission facilities. The Project represents the Minnesota portion of these major new transmission facilities, necessary to deliver the power called for under the Agreements.

Q. But couldn't a smaller transmission line still allow Minnesota Power to take the power to be delivered by the Manitoba Hydro agreements?

A. Again, Mr. Winter will discuss the smaller transmission line alternatives in greater detail. However, from my perspective a smaller transmission line would forfeit the full range of benefits to Minnesota Power and its customers delivered by the Project and the 133 Renewable Optimization Agreements. It is my view that a smaller transmission line would not accommodate the transfer of additional energy agreed upon under the 250 MW PPA and the 133 MW of the Renewable Optimization Agreements. The Project also allows Minnesota Power customers access to a more cost effective transmission line for delivering the power associated with the Manitoba Hydro Agreements than smaller transmission line alternatives, particularly given the Must Take Fee that I discussed above, leveraging even farther the economies of scale which a 500 kV line brings.

Regulators in the Province of Manitoba agreed that a larger transmission line provides "significant benefits . . . that go beyond the pure economics of the existing contract."[2] The Manitoba PUB specifically cited the ability of the Canadian companion line, which will connect with the Project at the United States

[2] Manitoba Public Utilities Board ("PUB"), Needs For and Alternatives To ("NFAT") Final Report, June 20, 2014, p. 28. Full Report available at www.pub.gov.mb.ca/nfat/pdf/finalreport_pdp.pdf.

– Canada border, to provide increased reliability to the region and to provide for increased export of hydropower to Minnesota and regional markets.[3]

B. State and Regional Needs

Q. How does the Project also meet State and regional energy needs?

A. The Project meets State and regional needs in multiple ways, including by facilitating the type of wind-water synergy made possible by the Manitoba Hydro Agreements. Manitoba Hydro has a long history of energy trading relationships with utilities in the United States and has potential future United States customers that have requested transmission service for delivery of energy and capacity from Manitoba. The Project will have enough capacity to deliver resources included in the Manitoba Hydro Agreements, as well as additional hydropower to other utilities in the United States. Thus, the Project can help meet future State and regional energy needs with a reliable, affordable and carbon-free resource.

As Mr. McMillan discusses, Manitoba Hydro is currently implementing a significant development plan that will provide key benefits to Minnesota Power and other Minnesota and regional utilities and their customers. As part of this development plan, Manitoba Hydro is constructing the 695-megawatt Keeyask Generating Station on the Nelson River and the Manitoba transmission facilities that will meet the Project at the United States – Canada border, providing

[3] *Id.*

additional capacity for new export sales from Manitoba. The Project, in conjunction with these activities in Manitoba, will support the sales to Minnesota Power already approved by the Commission in the 938 Docket, the sales under the 133 MW Renewable Optimization Agreements, and will allow for additional capacity and energy exchanges between Manitoba and United States utilities as needed, while also enhancing regional reliability and providing new regional sources of carbon-free energy and capacity.

Not only will the Project facilitate these additional capacity and energy exchanges, it will also facilitate significant addition of renewable generation, benefitting not just Minnesota Power and its customers, but benefitting other utilities and their customers as they strive to meet aggressive renewable energy standards.

As Mr. Hoberg discusses in more detail, the Midcontinent Independent System Operator ("MISO") recently conducted its first comprehensive study that looks at the synergy between Manitoba Hydro's hydroelectric power and wind power. The Manitoba Hydro Wind Synergy Study assessed how Manitoba hydroelectric power can work with MISO wind resources to provide benefits to electric customers within MISO. The study found that a new 500 kV interconnection with Manitoba will provide "significant benefits" to the entire MISO footprint. These benefits over 20 years were valued at approximately $1.6 billion in 2012 dollars and include substantial reductions in wind curtailment in the northern MISO region.

Further, the Project will provide a highly valuable new connection to energy resources in Manitoba. Currently, the regional transmission system includes only a single tie line between Manitoba and the United States that is comparable in size to the Project. As Mr. Winter discusses, development of a second 500 kV tie line from Manitoba to the Iron Range will reduce loading on the existing 500 kV tie line and improve the performance of the transmission system during this contingency.

In addition, the Project will strengthen the transmission system in an area poised for significant economic growth, with attendant electric load growth. The bulk of this load growth is associated with planned mining and industrial expansion on the Iron Range. Minnesota Power's large industrial customers demand reliable energy for their operations. Development of a second 500 kV interconnection on the Iron Range will provide another strong source of reliable power to a growing load pocket in our service territory.

Finally, as Mr. Winter discusses in more detail, the Project will improve overall transmission system efficiency. The Project will reduce overall transmission system losses and will also relieve the main constraint associated with the North Dakota – Manitoba loop flow phenomenon discussed by Mr. Winter. This will have the long-term impact of enabling considerable levels of simultaneous transfers of hydroelectric power from Manitoba and wind power from the Dakotas. Compared to other alternatives, the Project will provide the most long-term outlet capability from Manitoba and North Dakota before requiring the development of new transmission. As the Company's transmission alternatives analysis demonstrates, the Project is the best way to improve efficiency and reliability and maximize production and delivery of clean, carbon-free renewable energy into Minnesota and the Upper Midwest.

C. Additional Factors Supporting Need

Q. What additional factors should the Commission consider in determining the need for the Project?

A. The Project brings a number of benefits to Minnesota Power, our customers and the State and region, including positive economic impacts, environmental benefits through wind-hydro synergies, and overall increased reliability of the transmission system.

Q. Please discuss the positive economic impacts made possible by the Project.

A. First, the Project enables Minnesota Power to meet a growing customer need by taking delivery under the Manitoba Hydro Agreements. As the Department and Commission already affirmed, the 250 MW Agreements are the most appropriate resource available to meet that portion of the Company's needs. In making that determination, the Department and Commission considered a number of factors, including the price of the power. Affordable and reliable power is critical to Minnesota Power and its customers, including its industrial customers who are so central to the overall economic vitality of northeastern Minnesota.

By adding the hydropower made possible by the Project, Minnesota Power is simultaneously diversifying the Company's generation portfolio and reducing the overall emissions that would otherwise be associated with its electric supply portfolio. In this manner, the Project reduces Minnesota Power's system exposure to potential future emission reduction requirements and supports future economic development in the Company's service territory.

In addition, the Project provides economic benefits in the form of property tax revenue, construction and maintenance jobs, and increased business for hotels, restaurants, and other services along the final route. As Mr. Donahue discusses, to gauge the overall economic impact of the Project on the northern Minnesota economy, Minnesota Power contracted for the Labovitz Study, included as Appendix L to the Certificate of Need Application. The Labovitz Study found that the Project will generate over $850 million in economic impact in northern Minnesota for the design and construction period of 2016 through 2020, including approximately $29 million in State and local taxes and just over $30.5 million federal taxes throughout the course of the Project. In addition, it is estimated that property taxes will be in the range of $40,000 - $60,000 per mile annually after the line is placed in service.

D. Cost and Quality Control

Q. How does Minnesota Power intend to manage the Project to control costs, quality and schedule?

A. Minnesota Power has a successful tradition of implementing large capital projects. All of our projects require planning for safety, quality, and design or performance objectives up front including effective oversight during construction and project closeout. For large projects, we typically supplement with outside engineering consultants who jointly work with Company engineers. Large capital projects are developed and evaluated against a wide range of alternatives within the utility resource-planning context. Early in the project development phase, an internal Executive Sponsorship team is identified that provides executive accountability and oversight of the project from the regulatory filing phase to the project execution phase, where a qualified and appropriately experienced cross-functional Project Management team is assembled under the guidelines outlined in a Company Project Procedure Manual to successfully implement the project. Lessons learned are applied from previous large capital projects, to drive continuous improvement. The Project oversight will include the establishment of three important external governance features: (1) an external Board of

Consultants, (2) an owners engineer independent oversight, and (3) a qualified owner's engineer, under direction of the Project construction team.

The external Board of Consultants is envisioned to be represented by a group of qualified, independent technical engineers, with direct experience in similar transmission projects such as the Project to provide a sounding board for the Project Construction team.

An owner's engineer independent oversight firm will be hired to provide an objective and periodic written opinion to the executive sponsors as to Project progress, key milestones achieved, and key risks and costs throughout the Project.

Finally, Minnesota Power will select a qualified owners engineer to provide detailed design for the Project, in concert with Company engineering, legal and other Project construction professionals.

Together, this governance structure will provide robust planning, oversight and execution, to prudently manage all aspects of the Project.

E. Impact of Delay or Denial

Q. What impact would either delay or denial of a Certificate of Need for the Project have?

A. Delay or denial of a Certificate of Need for the Project would adversely impact Minnesota Power, its customers, the State and the region. For Minnesota Power, the most direct impact of denial would be the inability to take delivery of power from Manitoba Hydro under the Commission-approved 250 MW Agreements and under the 133 MW Renewable Optimization Agreements. Delay or denial of a Certificate of Need for the Project, and the resulting inability for Minnesota Power to take delivery of the contracted hydropower, would leave Minnesota Power with significant unmet needs beginning in 2020. Loss of the contract for and ability to access hydropower would come with an economic cost, as well as a cost in diversification of generation resources and a loss of the synergies possible through the coordination of wind and hydropower contemplated by Minnesota Power and Manitoba Hydro.

Additionally, denial of a Certificate of Need would mean the loss of the State and regional benefits that can be brought about by the Project, including the additional ability to take advantage of the wind-hydro synergies, the ability to meet regional needs with emission-free hydropower, building a more reliable system by reinforcing the connections between Minnesota and Manitoba, and increasing the transfer capability between Manitoba and the United States while simultaneously reducing wind curtailments.

Projects such as the Great Northern Transmission Line represent a once-in-a-generation opportunity, as large transmission projects that provide renewable energy, regional reliability enhancements, and mutually beneficial outcomes for so many stakeholders only are developed very infrequently. Synchronized development of and long term resource need solutions with Manitoba Hydro as represented by the Project in the State of Minnesota are unique opportunities, that if not seized at this time, may be forever lost.

Minnesota Power and Manitoba Hydro have made significant commitments to the Project and have already made substantial progress toward making the Project a reality. Once in service, the Project will bring substantial benefits to Minnesota Power, our customers, the State and the region. Delay or denial of the Certificate of Need surrenders those benefits and no other significant transmission project addressing the United States – Manitoba interconnection currently exists which can recover them.

III. GENERATION ALTERNATIVES

Q. Do generation alternatives provide a reasonable alternative to Minnesota Power when compared to the Project?

A. No. As I discussed above, Minnesota Power has significant resource needs beginning in the 2020 time frame as a result of customer load increase and reducing our reliance on smaller, less efficient coal units and declining off-take from Square Butte. To meet those needs, the Company has entered into the Manitoba Hydro Agreements, but only after conducting analyses that also considered market purchases; advanced coal-fired generation, combustion gas turbines and combined cycle gas turbines; other renewable generation; and incorporating demand side management and conservation across a wide range of future energy industry assumptions and sensitivities. As discussed in the 938 Docket approving the 250 MW Agreements, using its Strategist model for screening of reasonable alternatives, the Company concluded that a combined cycle unit may be the only reasonable alternative to the 250 MW Agreements.

The Manitoba Hydro Agreements provide more price certainty and mitigate carbon risks in Minnesota Power's future power supply. Additionally, when combined with our wind supply portfolio, the Manitoba Hydro Agreements bring Minnesota Power and our customers a flexible energy supply with base load characteristics and allow Minnesota Power to achieve its one-third renewable supply component objective outlined in **Energy*Forward***. In reviewing the 250 MW Agreements, the Department and Commission agreed that those Agreements provide the most appropriate resources for Minnesota Power to meet its resource needs over the period 2020 through 2035. Since this time, Minnesota Power has advanced its **Energy*Forward*** Resource Strategy to reduce emissions and deliver a more balanced system, with both the Project and the Manitoba Hydro Agreements, as well as at least 200 MW of new combined cycle generation being added sometime beyond 2020. If the Project were not built, Minnesota Power's **Energy*Forward*** vision for a balanced power supply would not be able to be realized, and would swing to potentially being over-reliant on natural gas generation portfolio.

Q. Has Minnesota Power also considered distributed generation as a means of meeting its resource needs?

A. Yes. Minnesota Power has examined distributed generation opportunities, including opportunities with its large industrial customers in its Resource Plan filings with currently 200 MW already in place. As the Company discussed in its 2013 Plan, we are working to develop a distributed generation program that can take advantage of some of the Minnesota Power service territory's unique customer and regional attributes to deliver cost effective energy solutions for our customers. For example, Minnesota Power has through the past decade supported over 100 small solar distributed generation installations on its system today, representing approximately 500 kW of nameplate capacity. In evaluating qualified load under Minnesota's new Solar Energy Standard, Minnesota Power anticipates adding an additional four MW of small solar (less than 20 kW) and approximately 29 MW of utility scale solar between now and 2020 onto its system. The majority of the distributed generation on Minnesota Power's system today is industrial distributed generation co-located at large paper and mining sites, specifically at Silver Bay, Cloquet, Duluth, Grand Rapids and International Falls. However, any distributed generation resources we and our customers may develop cannot displace the need for the Project and the substantial renewable energy and capacity deliveries to customers and the regional system optimization it makes available.

IV. CONSERVATION AND DEMAND SIDE MANAGEMENT

Q. Can Minnesota Power more reasonably meet its resource needs through conservation and demand side management efforts, rather than pursuing the Project?

A. No. First, I want to emphasize that Minnesota Power's Conservation Improvement Program ("CIP") is integral part of its resource planning. The Company's CIP efforts are detailed in Appendix K to our Application, which I also sponsor. As shown there, our CIP programs focus on increased efficiencies that reduce the amount of energy needed for certain uses and include eligible residential, commercial, and small scale renewable programs. Since 2010, our CIP efforts have resulted in surpassing the 1.5 percent annual savings goal set by State statute, saving 77,630 MWh in 2013. Even with our sustained Power of One conservation program as an integral component of Minnesota Power's overall **Energy*Forward*** resource planning, our customer load and energy supply outlook continue to demonstrate a need for the Project. By enabling the delivery of carbon free hydroelectric power provided by the Manitoba Hydro Agreements, this Project delivers critical resources to meet our customers' energy supply needs and advances Minnesota Power's **Energy*Forward*** resource strategy while delivering on State and federal public policy objectives. In parallel path, through Power of One, our continued strong conservation programs will improve our customers' efficient use of electricity.

Q. Does that conclude your direct testimony?

A. Yes it does.

9382804v1

minnesota power

AN ALLETE COMPANY

July 1, 2014

Minnesota Department of Commerce
85 – 7th Place East
St. Paul, MN 55101

RE: Docket No. E-999/PR-14-11

Re: MINNESOTA POWER'S 2014 ANNUAL ELECTRIC UTILITY FORECAST REPORT
Minnesota laws and reporting rules governing electric utilities require that electric utilities with Minnesota service areas submit to the Minnesota Department of Commerce an annual report. This report is to be submitted by July 1 of each year. Attached is a copy of Minnesota Power's 2014 Annual Electric Utility Forecast Report that contains all of the forms and information necessary to meet this requirement.

Trade Secret information is included in the "2014ElectricUtilityDataReport_68.xlsx" and "2014Forecast_68.xlsx" Excel workbooks as well as the methodology document "METHOD14.pdf."

Minnesota Power has excised material from the public version of the attached report documents as they identify and contain confidential, competitive information regarding Minnesota Power's methods, techniques and process for supplying electric service to its customers. The energy usage by specific customers and generation by fuel type has been consistently treated as Trade Secret in individual filings before the Minnesota Public Utilities Commission. Minnesota Power follows strict internal procedures to maintain the privacy of this information. The public disclosure of this information would have severe competitive implications for customers and Minnesota Power.

Minnesota Power is providing this justification for the information excised from the attached report and why the information should remain trade secret under Minn. Stat. 13.37. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the Trade Secret designation provided herein.

The following documents have been uploaded to the Minnesota Department of Commerce and Public Utilities Commission eDockets/eFiling system: METHOD14.pdf, 2014Forecast.xls, 2014ElectricUtilityDataReport.xls, MP System Map.pdf, and MP Ratebook.pdf. As of this date, the report form EIA 861 has not been filed with the US Department of Energy and cannot be submitted with Annual Electric Utility Report. The report form EIA 861 will be filed with the Minnesota Department of Commerce and Public Utilities Commission eDockets system as soon as possible. If you need additional paper copies or have any questions, please contact myself or the Minnesota Power Resource Planning area.

Ben Levine
Utility Load Forecaster
Minnesota Power
218-355-3120 - Direct
Blevine@mnpower.com

Cc: Julie Pierce
David Moeller
Lori Hoyum

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0120 REGISTRATION

ENTITY ID#	68
REPORT YEAR	2013

Number of Power Plants	18

UTILITY DETAILS

UTILITY NAME	Minnesota Power
STREET ADDRESS	30 West Superior Street
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	218-722-5642
* UTILITY TYPE	Private

CONTACT INFORMATION

CONTACT NAME	Julie Pierce
CONTACT TITLE	Manager - Resource Planning
CONTACT STREET ADDRESS	30 West Superior Street
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	(218) 722-5642 x 3829
CONTACT E-MAIL	Jpierce@Mnpower.com

UTILITY OFFICERS

NAME	TITLE
Alan R. Hodnik	Chairman, President, and Chief Executive Officer
David J. McMillan	Senior Vice President, External Affairs
Deborah A. Amberg	Senior Vice President, General Counsel and Secretary
Steven Q. DeVinck	Senior Vice President and Chief Financial Officer
Allan S. Rudeck, Jr.	Vice President, Strategy & Planning
Robert J. Adams	Vice President,Energy Centric Businesses and ALLETE Chief Risk Officer
Donald W. Stellmaker	Vice President, Corporate Treasurer
Timothy J. Thorp	Vice President, Investor Relations
Bonnie A. Keppers	Vice President, Human Resources
Patrick K. Mullen	Vice President, Marketing & Corporate Communications
Margaret L. Hodnik	Vice President, Regulatory & Legislative Affairs
Jeffrey J. Paulseth	Vice President, Generation
Christopher E. Fleege	Vice President, Transmission and Distribution
Bethany Owen	Vice President, Information Technology Solutions
Bradley W. Oachs	Chief Operating Officer
Steve Morris	Controller

PREPARER INFORMATION

PERSON PREPARING FORMS	
PREPARER'S TITLE	
DATE	

COMMENTS

ALLOWABLE UTILITY TYPES

Code

Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0150 FEDERAL OR STATE DATA SUBSTITUTION

FEDERAL AGENCY	FORM NUMBER	FORM TITLE	FILING CYCLE (enter an "X" in the cell) MONTHLY	YEARLY	OTHER
FERC	FERC-1	Annual FERC Report		X	
FERC	FERC-5	Statement of Electric Operating Revenue and Income	X		
FERC	FERC-45	Part 45 Informational Report			X
FERC	FERC-67	Steam Electric Plant, Air and Water Survey		X	
FERC	FERC-80	Licensed Projects Recreation Report			X
FERC	FERC-82	Retail Rate Level Change			X
DOE/EIA	EIA-411	Coordinated Bulk Power Supply Program		X	
DOE/EIA	EIA-412	Annual Electric Industry Financial Report (Unregulated)		X	
DOE/EIA	EIA-423	Report of Cost and Quality of Fuels for Electric Plant (Unregulated)	X		
FERC	FERC-423	Fuel Data			X
FERC	FERC-469	Statement of Gross Generation by Licensed Projects		X	
FERC	FERC-472	Regulation Number 582 - Assessment Calculation		X	
DOE/EIA	DOE-510	Response to FERC Operation Report		X	
		(Written Communication for each Licensed Project)			
FERC	FERC-561	Interlocking Directors and Officers		X	
FERC	FERC-566	Twenty Largest Customers		X	
DOE/EIA	EIA-714	Electric Power System Report		X	
DOE/EIA	EIA-767	Steam Electric Plant Air and Water Quality Control Data		X	
DOE/EIA	EIA-906	Power Plant Report (Regulated Facilities)	X		
DOE/EIA	EIA-906	Power Plant Report (Unregulated Facilities)	X		
DOE/EIA	FE781R	Report of International Electric Import/Export		X	
DOE/EIA	EIA-826	Electric Utility Sales and Revenue Report with Distributions	X		
DOE/EIA	EIA-860	Electric Generator Report (Regulated Facilities)		X	
DOE/EIA	EIA-860	Electric Generator Report (Unregulated Facilities)		X	
DOE/EIA	EIA-861	Electric Utility Report (Regulated)		X	
DOE/EIA	EIA-861	Electric Utility Report (Unregulated)		X	
DOE/EIA	EIA-886	Alternative Fueled Vehicles/Transportation Fuels Report		X	
DOE/EIA	EIA-196	Order Authorizing Electricity Exports to Canada		X	
FERC	FERC-69	PURPA Avoided Capacity Cost Filing			X
FRB		NAICS/SIC Listing of Electricity Delivered	X		
SEC	Form 10-K	Annual SEC Report		X	
SEC	Form 10-Q	Quarterly SEC Report			X
SEC	Form 8-K	Current SEC Report			X
SEC	Form S-8	SEC Registration Statement S-8			X
SEC	Form S-3	SEC Registration Statement S-3			X
SEC	Form 3	Initial Statement of Beneficial Ownership of Securities			X
SEC	Form 4	Statement of Changes of Beneficial Ownership of Securities			X
SEC	Form 5	Annual Statement of Beneficial Ownership of Securities		X	
SEC	Proxy	Definitive Proxy Statement		X	
SEC	U-3A-2	Statement by Holding Company Claiming Exemption Under		X	
		Rule U-3A-2 from the Provisions of the Public Utility			
		Holding Company Act of 1935			
SEC	Form 11-K	Annual Report for RSOP		X	
SEC	Form 15	Certification and Notification of Termination of Registration			X
SEC	Form S-1	SEC Registration Statement			X

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

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

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

If applicable, the Largest Customer List must be submitted either in electronic or paper format. If information is Trade Secret, note it as such.

See "LargestCustomers" worksheet for data entry.

C. MINNESOTA SERVICE AREA MAP

The referenced map must be submitted either in electronic or paper format.

See Instructions for details of the information required on the Minnesota Service Area Map.

D. PURCHASES AND SALES FOR RESALE

UTILITY NAME	INTERCONNECTED UTILITY	MWH PURCHASED	RESALE ONLY MWH SOLD FOR RESALE
Dahlberg Light & Power			115,816
Superior Water Light & Power			701,845
City of Aitkin			38,878
City of Biwabik			7,259
City of Brainerd			202,882
City of Buhl			8,183
City of Ely			40,422
City of Gilbert			11,671
City of Grand Rapids			177,955
City of Keewatin			6,069
City of Mountain Iron			14,803
City of Nashwauk			11,005
City of Pierz			10,754
City of Proctor			26,834
City of Randall			5,242
City of Two Harbors			29,859
City of Hibbing			162,239
City of Virginia			129,277
Other Non-Required Sales			2,278,253
Non-Associated Utilities/Other		348,045	
Municipals			
Other Cooperatives		20,173	
Square Butte Electric Power		1,254,622	
Non-Utilities		86,300	
Power Marketers		47,250	
Other Public Authorities		1,905,070	
Utility		3	
Foreign		268,564	
City of Wadena	Western Area Power Administration	72,983	72,983
City of Staples	Western Area Power Administration	23,905	23,905
Great River Energy	Great River Energy	2,545,857	2,462,598
ES&AO	Minnkota Power	1,255,445	1,255,445

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

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

E. RATE SCHEDULES

The rate schedule and monthly power cost adjustment information must be submitted in electronic or paper format.

See Instructions for details of the information required on the Rate Schedules and Monthly Power Cost Adjustments.

Billing Month	Retail Fuel Adjustments
Jun-13	$0.0103
Jul-13	$0.0110
Aug-13	$0.0098
Sep-13	$0.0098
Oct-13	$0.0106
Nov-13	$0.0122
Dec-13	$0.0121
Jan-14	$0.0112
Feb-14	$0.0128
Mar-14	$0.0139
Apr-14	$0.0118
May-14	$0.0105
Jun-14	$0.0015

F. REPORT FORM EIA-861

A copy of report form EIA-861 filed with the US Dept. of Energy must be submitted in electronic or paper format.

A copy of the report form EIA-861 filed with the Energy Information Administration of the US Dept. of Energy must be submitted.

G. FINANCIAL AND STATISTICAL REPORT

If applicable, a copy of the Financial and Statistical Report filed with the US Dept. of Agriculture must be submitted in electronic or paper format.

For rural electric cooperatives, a copy of the Financial and Statistical Report to the US Dept of Agriculture must be submitted.

H. GENERATION DATA

If the utility has Minnesota power plants, enter the fuel requirements and generation data on the Plant1, Plant2, etc. worksheets.

I. ELECTRIC USE BY MINNESOTA RESIDENTIAL SPACE HEATING USERS

See Instructions for details of the information required for residential space heating users.

COL. 1 NO. OF RESIDENTIAL ELECTRICAL SPACE HEATING CUSTOMERS	COL. 2 NO. OF RESIDENTIAL UNITS SERVED WITH ELECTRICAL SPACE HEATING	COL. 3 TOTAL MWH USED BY THESE CUSTOMERS AND UNITS
13,897	13,897	193,320

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY COUNTY FOR THE LAST CALENDAR YEAR

ENERGY DELIVERED TO ULTIMATE CONSUMERS BY COUNTY

COUNTY CODE	COUNTY NAME	MWH DELIVERED	COUNTY CODE	COUNTY NAME	MWH DELIVERED
1	Aitkin		46	Martin	
2	Anoka		47	Meeker	
3	Becker		48	Mille Lacs	
4	Beltrami		49	Morrison	293675
5	Benton	25329	50	Mower	
6	Big Stone		51	Murray	
7	Blue Earth		52	Nicollet	
8	Brown		53	Nobles	
9	Carlton	462260	54	Norman	
10	Carver		55	Olmstead	
11	Cass	123623	56	Otter Tail	529
12	Chippewa		57	Pennington	
13	Chisago		58	Pine	74562
14	Clay		59	Pipestone	
15	Clearwater		60	Polk	
16	Cook		61	Pope	
17	Cottonwood		62	Ramsey	
18	Crow Wing	134722	63	Red Lake	
19	Dakota		64	Redwood	
20	Dodge		65	Renville	
21	Douglas		66	Rice	
22	Faribault		67	Rock	
23	Fillmore		68	Roseau	
24	Freeborn		69	St. Louis	7206995
25	Goodhue		70	Scott	
26	Grant		71	Sherburne	
27	Hennepin		72	Sibley	
28	Houston		73	Stearns	7738
29	Hubbard	98866	74	Steele	
30	Isanti		75	Stevens	
31	Itasca	297340	76	Swift	
32	Jackson		77	Todd	205321
33	Kanabec		78	Traverse	
34	Kandiyohi		79	Wabasha	
35	Kittson		80	Wadena	97386
36	Koochiching	175843	81	Waseca	
37	Lac Qui Parle		82	Washington	
38	Lake	80627	83	Watonwan	
39	Lake of the Woods		84	Wilkin	
40	Le Sueur		85	Winona	
41	Lincoln		86	Wright	
42	Lyon		87	Yellow Medicine	
43	McLeod				
44	Mahnomen			GRAND TOTAL (Entered)	9284816
45	Marshall				
				GRAND TOTAL (Calculated)	9284816

<= (Should equal "Megawatt-hours" column total on ElectricityByClass worksheet)

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY MONTH FOR THE LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Past Year Entire System		A Non-Farm Residential	B Residential With Space Heat	C Farm	D Small Commercial & Industrial	E Irrigation	F Large Commercial & Industrial	G Street & Highway Lighting	H Other (Include Municipals)	I Total (Columns A through H)
January	No. of Customers	104,962	13,891	2,408	22,020	8	395	7,433	287	151,404
	MWH	93,138	29,681	6,544	107,176	422,039	170,543	1,872	4,263	835,256
February	No. of Customers	104,745	13,895	2,403	21,907	8	396	7,536	285	151,175
	MWH	64,815	30,944	6,475	104,617	384,876	155,608	1,575	4,445	753,354
March	No. of Customers	104,774	13,869	2,405	21,869	8	395	7,622	286	151,228
	MWH	63,385	25,689	5,986	112,689	418,241	178,460	1,477	4,407	810,334
April	No. of Customers	104,775	13,846	2,397	21,898	8	394	8,060	288	151,666
	MWH	63,527	22,243	5,867	94,990	353,641	167,441	1,222	4,241	713,172
May	No. of Customers	105,012	13,896	2,404	21,905	8	393	8,918	289	152,825
	MWH	55,005	15,677	5,217	95,218	416,509	154,783	1,186	2,899	746,493
June	No. of Customers	105,901	13,935	2,405	21,781	8	393	9,436	286	154,145
	MWH	49,131	8,578	5,538	100,630	399,285	175,244	862	4,690	743,957
July	No. of Customers	105,116	13,832	2,397	21,936	8	395	9,443	288	153,415
	MWH	74,417	5,630	5,054	104,618	423,037	178,814	822	4,246	796,638
August	No. of Customers	105,050	13,891	2,397	21,876	8	395	9,439	288	153,344
	MWH	65,704	4,869	5,323	111,749	413,133	184,303	1,125	4,710	790,916
September	No. of Customers	105,213	13,927	2,389	21,919	8	394	12,900	289	157,039
	MWH	67,604	5,359	5,782	113,337	401,128	176,142	1,269	4,623	775,244
October	No. of Customers	104,938	13,919	2,382	21,958	8	396	13,023	290	156,914
	MWH	52,815	5,937	4,815	90,803	386,830	176,799	1,451	3,807	723,256
November	No. of Customers	104,913	13,921	2,390	21,958	8	393	13,076	287	156,946
	MWH	82,835	13,635	5,012	103,246	418,679	146,010	1,466	3,987	774,870
December	No. of Customers	104,832	13,947	2,386	21,956	8	390	13,142	285	156,946
	MWH	93,239	25,077	5,934	117,468	413,603	158,848	1,738	5,419	821,326
	Total MWH	825,615	193,320	67,547	1,256,540	4,850,998	2,022,995	16,066	51,736	9,284,816

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

ELECTRICITY DELIVERED TO ULTIMATE CONSUMERS IN MINNESOTA SERVICE AREA IN LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Exclude station use, distribution losses, and unaccounted for energy losses from this table altogether.

Classification of Energy Delivered to Ultimate Consumers (include energy used during the year for irrigation and drainage pumping)	In this column report the number of farms, residences, commercial establishments, etc., and not the number of meters, where different. Number of Customers at End of Year	This column total should equal the grand total in the worksheet labeled "ElectricityByCounty" which provides deliveries by county. Megawatt-hours (round to nearest MWH)	This column total will be used for the Alternative Energy Assessment and should not include revenues from sales for resale (MN Statutes Sec. 216B.62, Subd. 5). Revenue ($)
Farm	2,386	67,547	6,449,028
Nonfarm-residential	118,779	1,018,934	94,054,285
Commercial	21,956	1,256,540	103,685,175
Industrial	390	6,873,992	370,024,629
Street and highway lighting	13,142	16,066	2,118,210
All other	285	51,736	4,052,775
Entered Total	153,921	9,284,816	580,384,102
CALCULATED TOTAL	156,938	9,284,816	580,384,102

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

PLEASE PROVIDE THE FOLLOWING INFORMATION FOR THOSE CUSTOMERS USING IN EXCESS OF 10,000 MWH. BE SURE TO INCLUDE YOUR LARGE CUSTOMERS LOCATED IN AND OUTSIDE MINNESOTA.

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

Trade Secret Data Excised

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	MWH

COMMENTS

	REMEMBER TO SEND THE FOLLOWING ATTACHMENTS:
1	If applicable, the Largest Customer List (Attachment ELEC-1), if the LargestCustomers worksheet was not used (pursuant to MN Rules Chapter 7610.0600 B.)
2	Minnesota service area map (pursuant to MN Rules Chapter 7610.0600 C.)
3	Rate schedules and monthly power cost adjustments (pursuant to MN Rules Chapter 7610.0600 E.)
4	Report form EIA-861 filed with US Dept. of Energy (pursuant to MN Rules Chapter 7610.0600 F.)
5	If applicable, for rural electric cooperatives, the Financial and Statistical Report filed with US Dept. of Agriculture (pursuant to MN Rules Chapter 7610.0600 G.)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Boswell Energy Center	PLANT ID	68003
STREET ADDRESS	1210 NW 3rd Street		
CITY	Cohasset		
STATE	MN	UNITS	4
ZIP CODE	55721		
COUNTY	Itasca		
CONTACT PERSON	William Boutwell		
TELEPHONE	218-328-5036 x4433		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1958	COAL	440,045	
2	USE	ST	1960	COAL	472,273	
3	USE	ST	1973	COAL	2,552,577	
4	USE	ST	1980	COAL	3,404,497	MP share
					6,869,392	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	67.125	67.125	74.98	91.65	1.39	
2	67.325	67.325	80.46	96.68	0.39	
3	357.225	357.225	82.78	92.54	3.34	
4	466.974	466.974	83.83	92.53	1.45	
	958.649	958.649	80.51	93.35	1.64	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)					
Unit ID #	Fuel Type ***	Quantity		BTU Content (for coal only)			Unit of Measure ****	GAS***	QUANITY	UNITS OF MEASURE****
1	SUB	270,082	TONS	8,938	FO2	0	GAL	NG	29046	Mbtu's
2	SUB	294,417	TONS	8,944	FO2	0	GAL	NG	15991	Mbtu's
3	SUB	1,513,720	TONS	8,970	FO2	0	GAL	NG	54425	Mbtu's
4	SUB	2,453,874	TONS	9,055	FO2	0	GAL	NG	65642	Mbtu's

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Laskin Energy Center	PLANT ID	68015
STREET ADDRESS	PO Box 166		
CITY	Aurora		
STATE	MN	NUMBER OF UNITS	2
ZIP CODE	55705		
COUNTY	Saint Louis		
CONTACT PERSON	William Boutwell		
TELEPHONE	218-328-5036 x4433		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1953	COAL	241,385	
2	USE	ST	1953	COAL	230,386	
					471,771	

C. UNIT CAPABILITY DATA — CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	48.8	48.8	57.28	88.04	1.16	
2	49.4	49.4	52.53	84.99	4.37	
	98.2	98.2	54.91	86.52	2.77	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity		BTU Content (for coal only)			Unit of Measure ****	
1	SUB	179,354		8735	FO2	21	GAL	
2	SUB	170,803		8735		21		
					NG	21,016	Mbtu's	
						21,016		

NOTE: Fuels are not metered separately for these units

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage): Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage): 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage): Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	M.L. Hibbard	PLANT ID	68009
STREET ADDRESS	4913 Main Street		
CITY	Duluth		
STATE	MN	NUMBER OF UNITS	2
ZIP CODE	55807		
COUNTY	Saint Louis		
CONTACT PERSON	David Pessenda		
TELEPHONE	218-628-3627 x5713		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
3	USE	ST	1949	SUB/WOOD	5,155	
4	USE	ST	1951	SUB/WOOD	20,061	
					25,216	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
3	25.603	25.603	1.84	83.26	73.54	
4	32.85	32.85	8.30	88.51	0.02	
	58.5	58.5	5.07	85.89	36.78	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity		BTU Content (for coal only)			Unit of Measure ****	BTU Content (for coal only)
3	SUB	37		8,930	NG	32,311	MCF	
	WOOD	17,493		8,983				
4	SUB	37		8,930				
	WOOD	17,493		8,983				

ALLOWABLE CODES

Cell Heading	**Code**	**Code Definition**	**Cell Heading**		**Code Definition**
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source &**	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Rapids Energy Center	PLANT ID	68025
STREET ADDRESS	502 NW 3rd Street		
CITY	Grand Rapids		
STATE	MN	UNITS	4
ZIP CODE	55744		
COUNTY	Itasca		
CONTACT PERSON	Frank Frederickson		
TELEPHONE	218-326-6083 x6990		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
6	USE	ST	1969	GAS/WOOD/COAL	42,699	
7	USE	ST	1980	WOOD/COAL	62,280	
4	USE	HC	1917	HYD	2,809	
5	USE	HC	1948	HYD	5,569	
					113,357	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
6	11.4	11.4	46.87	90.26	0.99	
7	13.0	13.0	54.69	84.49	1.81	
4	0.75	0.75	40.50	99.0	1.00	
5	1.5	1.5	41.60	76	14	
	26.7	26.7	45.92	87.4	4.5	

D. UNIT FUEL USED

PRIMARY FUEL USE

Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)
6	NG	36,933	MCF					
6	SUB	11,527	TONS					9,313
6	WOOD	42,393	TONS					
7	SUB	6,181	TONS					
7	WOOD	21,123	TONS					

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)	Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce	Note: Failure of a unit to be available does not include down time for scheduled maintenance.
Operating Availability (percentage)	100 - Maintenance percentage - Forced Outage percentage	Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.
Capacity Factor = (percentage)	Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760	

	#7 TG	#6 TG	#5 Hydro	#4 Hydro
Total Hours Down	380	2672	2560	2123
Sched Maint	236	844	0	0
Forced Outage	144	1828	2560	2123
Maint Percentage	0.026940639	0.09634703	0	0
Forced Outage Rate	1.643835616	20.8675799	29.22374429	24.23515982
Operating factor	98.32922374	79.0360731	70.77625571	75.76484018
Capacity factor	50.456621	22.2688313	30.31018737	65.84221208

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	SAPPI Cloquet Turb Genr #5	PLANT ID	68020
STREET ADDRESS	2201 Avenue B		
CITY	Cloquet		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE	55720		
COUNTY	Carlton		
CONTACT PERSON	Rochon Kinney		
TELEPHONE	218-722-5642 x3297		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
5	USE	ST	2001	WOOD/GAS	98,022	
					98,022	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
5	22.785	22.785	50.78%	81.11%	6.62%	
	22.785	22.785	51.46%	81.11%	6.62%	

D. UNIT FUEL USED

PRIMARY FUEL USE					ECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)
5	WOOD	22,372	tons		Gas	201,351	MCF	

LOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate :rs Unit Failed to be Available X 100
(percentage) ours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability ance percentage - Forced Outage percentage
(percentage)

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = Annual MWH of Production X 100
(percentage) Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Taconite Harbor	PLANT ID	68026
STREET ADDRESS	PO Box 64		
CITY	Schroeder		
STATE	MN	NUMBER OF UNITS	3
ZIP CODE	55705		
COUNTY	Cook		
CONTACT PERSON	William Boutwell		
TELEPHONE	218-370-0650		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1953	COAL	277,704	
2	USE	ST	1953	COAL	338,381	
3	USE	ST	1954	COAL	448,349	
					1,064,434	

*THEC unit figures may not total net figures due to station service

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	78.7	78.7	45.18	72.39	3.51	
2	76.05	76.05	55.39	91.20	1.89	
3	83	83	71.09	91.87	4.02	
	237.75	237.75	57.22	85.15	3.14	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity		BTU Content (for coal only)			Unit of Measure ****	
1	SUB	180,741	TONS	9,044	FO2	64,228	GAL	
2	SUB	220,489	TONS	9,034	FO2	30,068	GAL	
3	SUB	267,268	TONS	9,024	FO2	51,161	GAL	

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) urs Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce — Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 00 - Maintenance percentage - Forced Outage percentag — Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
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Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Thomson Hydroelectric Station	PLANT ID	68016
STREET ADDRESS	180 St, Hwy 210		
CITY	Carlton		
STATE	MN	UNITS	6
ZIP CODE	55718		
COUNTY	Carlton		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1907	HYD	0.0	Flood Damage
2	USE	HC	1907	HYD	0.0	Flood Damage
3	USE	HC	1907	HYD	0.0	Flood Damage
4	USE	HC	1914	HYD	0.0	Flood Damage
5	USE	HC	1918	HYD	0.0	Flood Damage
6	USE	HC	1949	HYD	0.0	Flood Damage
					0.0	

Unit net figures may not add up to the station net figurs due to station service.

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	11.5	11.5	0.00%	0.00%	100.00%	
2	11.5	11.5	0.00%	0.00%	100.00%	
3	11.5	11.5	0.00%	0.00%	100.00%	
4	11.9	11.9	0.00%	0.00%	100.00%	
5	10.4	10.4	0.00%	0.00%	100.00%	
6	13.6	13.6	0.00%	0.00%	100.00%	
	70.4	70.4	0.00%	0.00%	0.00%	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage): Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage): 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage): Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
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Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Blanchard Hydroelectric Station	PLANT ID	68001
STREET ADDRESS	PO Box 157		
CITY	Little Falls		
STATE	MN	NUMBER OF UNITS	3
ZIP CODE	56345		
COUNTY	Morrison		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1925	HYD	32,059.3	
2	USE	HC	1925	HYD	35,691.3	
3	USE	HC	1988	HYD	19,211.6	
					86,962.2	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	3.427	3.427	61.00%	99.52%	0.31%	
2	4.013	4.013	67.91%	90.46%	9.41%	
3	3.26	3.26	36.55%	99.50%	0.07%	
	10.70	10.7	55.15%	96.49%	3.26%	

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity			SECONDARY FUEL USE (START UP)		Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Pillager Hydroelectric Station	PLANT ID	68011
STREET ADDRESS	13449 Pillager Dam Road		
CITY	Pillager		
STATE	MN	UNITS	2
ZIP CODE	56473		
COUNTY	Cass		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1917	HYD	4,929.5	
2	USE	HC	1917	HYD	3,546.9	
					8,476.4	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.65	0.65	70.34%	99.89%	0.11%	
2	0.65	0.65	50.61%	98.28%	1.72%	
	1.30	1.29	60.48%	99.09%	0.92%	

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity			SECONDARY FUEL USE (START UP)		Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$
Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage
Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Little Falls Hydroelectric Station	PLANT ID	68007
STREET ADDRESS	1 Hydro Street		
CITY	Little Falls		
STATE	MN	NUMBER OF UNITS	6
ZIP CODE	56345		
COUNTY	Morrison		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1919	HYD	4542.8	
2	USE	HC	1919	HYD	5480.8	
3	USE	HC	1920	HYD	7850.8	
4	USE	HC	1979	HYD	10157.8	
5	USE	HC	1906	HYD	2133.8	
6	USE	HC	1906	HYD	2437.8	
					32603.8	

THOM unit totals may not equal the total due to station service calculations.

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.60	0.60	64.82%	99.86%	0.14%	
2	0.60	0.60	78.21%	100.00%	0.00%	
3	0.60	0.60	81.47%	99.94%	0.06%	
4	0.60	0.60	105.42%	98.64%	1.36%	
5	0.60	0.60	60.90%	95.60%	4.40%	
6	0.60	0.60	69.57%	98.57%	1.43%	
	3.60	3.60	76.73%	98.77%	1.23%	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage)

100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA			
PLANT NAME	Scanlon Hydroelectric Station	PLANT ID	68013
STREET ADDRESS			
CITY	Scanlon		
STATE	MN	UNITS	4
ZIP CODE	55720		
COUNTY	Carlton		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1923	HYD	1,454.9	
2	USE	HC	1923	HYD	2,329.4	
3	USE	HC	1923	HYD	1,351.6	
4	USE	HC	1923	HYD	1,992.1	
					7,128.0	

Unit net figues may not total station net figures due to station service calculations.

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.02	0.02	39.13%	97.83%	2.17%	
2	0.02	0.02	64.09%	96.42%	0.00%	
3	0.02	0.02	36.18%	97.12%	0.55%	
4	0.02	0.02	53.89%	88.71%	7.67%	
	0.08	0.08	48.32%	95.02%	2.60%	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity		BTU Content (for coal only)			Unit of Measure ****	

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)
Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage)
100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)
Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Sylvan Hydroelectric Station	PLANT ID	68014
STREET ADDRESS	13753 Sylvan Dam Road		
CITY	Pillager		
STATE	MN	UNITS	3
ZIP CODE	56473		
COUNTY	Cass		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1913	HYD	3,366.8	
2	USE	HC	1913	HYD	3,068.0	
3	USE	HC	1915	HYD	1,867.7	
					8,302.5	

Unit net figures may not total the station net due to station service calculations

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.4	0.4	61.60%	99.92%	0.00%	
2	0.4	0.4	55.92%	99.92%	0.00%	
3	0.4	0.4	33.07%	95.82%	4.10%	
	1.2	1.2	50.20%	98.55%	1.37%	

D. UNIT FUEL USED

PRIMARY FUEL USE | SECONDARY FUEL USE (START UP)

Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA			
PLANT NAME	Winton Hydroelectric Station	PLANT ID	68019
STREET ADDRESS	PO Box 156		
CITY	Winton		
STATE	MN	NUMBER OF UNITS	2
ZIP CODE	55796		
COUNTY	Lake		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
2	USE	HC	1923	HYD	9,413.0	
3	USE	HC	1923	HYD	12,145.0	
					21,558.0	

Unit net figures may not total the station net figures due to station service calculations.

C. UNIT CAPABILITY DATA — CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
2	1.10	1.10	53.73%	99.90%	0.10%	
3	1.20	1.20	69.32%	100.00%	0.00%	
	2.30	2.30	61.53%	99.95%	0.05%	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Knife Falls Hydroelectric Station	PLANT ID	68006
STREET ADDRESS			
CITY	Cloquet		
STATE	MN	NUMBER OF UNITS	3
ZIP CODE	55720		
COUNTY	Carlton		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1922	HYD	2,635.5	
2	USE	HC	1922	HYD	3,191.9	
3	USE	HC	1922	HYD	3,807.3	
					9,634.7	

Unit net figures may not total the station net figures due to station service calculations.

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.3	0.3	35.10%	96.00%	0.47%	
2	0.3	0.3	43.04%	94.52%	5.48%	
3	0.3	0.3	51.82%	95.91%	0.00%	
	0.9	0.9	43.32%	95.48%	1.98%	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT:2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Fond Du Lac Hydroelectric Station	PLANT ID	68005
STREET ADDRESS	14302 Oldenberg Parkway		
CITY	Duluth		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE	55808		
COUNTY	Saint Louis		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1924	HYD	14312.2	online 6/28/13
					14312.2	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	11.1	11.1	14.46	37.71	8.18	
	11.1	11.1	14.46	37.71	8.18	

D. UNIT FUEL USED

PRIMARY FUEL USE Unit ID #	Fuel Type ***	Quantity			SECONDARY FUEL USE (START UP)		Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Prairie River Hydroelectric Station	PLANT ID	68012
STREET ADDRESS			
CITY	Grand Rapids		
STATE	MN	NUMBER OF UNITS	2
ZIP CODE	55734		
COUNTY	Itasca		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1921	HYD	612.1	
2	USE	HC	1921	HYD	681.0	
					1,293.1	

C. UNIT CAPABILITY DATA — CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.5	0.5	9.98	50.22	49.78	
2	0.5	0.5	19.43	47.75	52.25	
	1	1	14.71	48.99	51.02	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source & Fuel Type**	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquified Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage): Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage): 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage): Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Taconite Ridge 1	PLANT ID	(leave this cell blank)
TREET ADDRESS	Co Rd 102		
CITY	Mountain Iron		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE	55768		
COUNTY	St. Louis		
ONTACT PERSON	Todd Simmons		
TELEPHONE	218-722-5642 x 6102		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	Use	WI	2008	Wind	55,891	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	25.0	25.0	26.5	87.7	10.9	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	of Measure	BTU Content (for coal only)
1	Wind	n/a	n/a	n/a	n/a	n/a	n/a	n/a

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source**	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

orced Outage Rate (percentage)	Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce	Note: Failure of a unit to be available does not include down time for scheduled maintenance.
erating Availabilit (percentage)	100 - Maintenance percentage - Forced Outage percentage	Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.
Capacity Factor = (percentage)	Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760	

Note: Per Julie Pierce Tac Ridge is to be reported as a single entity

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA			
PLANT NAME	Bison 1	PLANT ID	(leave this cell blank)
STREET ADDRESS	5198 30th Street		
CITY	New Salem		
STATE	ND	NUMBER OF UNITS	1
ZIP CODE	58563		
COUNTY	Morton		
CONTACT PERSON	Todd Simmons		
TELEPHONE	218-843-6102		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	Use	WI	2010	Wind	780,799	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	81.8	291.8	30.50	96.22	3.73	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	of Measure	BTU Content (for coal only)
1	Wind	n/a	n/a	n/a	n/a	n/a	n/a	n/a

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear

*** Energy Source & **Fuel Type**	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)	Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce	Note: Failure of a unit to be available does not include down time for scheduled maintenance.
Operating Availability = (percentage)	100 - Maintenance percentage - Forced Outage percentage	Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.
Capacity Factor = (percentage)	Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760	

Contents

Introduction

The utility customer load forecast is the initial step in electric utility planning. Capacity and energy resource commitments are based on forecasts of energy consumption, and seasonal peak demand requirements. Minnesota Power's forecast process combines sound econometric methodology and data from reputable sources to produce a reasonable long-term outlook suitable for planning.

Minnesota Power is committed to continuous forecast process improvement, process transparency, forecast accuracy, and gaining customer insight. This 2014 forecast methodology document demonstrates Minnesota Power's continued efforts to meet these goals through comprehensive documentation, implementation of more systematic and replicable processes, and thorough analysis of results.

A history of increasing accuracy in load forecasting also speaks to Minnesota Power's commitment to innovate and enhance its forecast processes. Since 2000, year-ahead forecast error has decreased by an average 0.04 percent per-year; current-year forecast error has decreased at an average rate of 0.16 percent per-year.[1] Minnesota Power owes its record of forecast accuracy to a combination of close cooperation with customers, continuous validation of forecast model inputs, and steady improvements in statistical analytic capabilities.

The range of scenarios developed for the 2014 Advance Forecast Report (AFR 2014) address the uncertainty in the national and regional economic environments and the unique potential for local additions or losses to the Resale and Industrial customer classes, including the development of substantial mining operations in the region. This scenario approach to forecasting can then be integrated into Minnesota Power's proactive and flexible planning to better inform the critical electric resource decisions ahead. Minnesota Power's forecasting approach helps keep the potential demand and energy outcomes transparent and robust.

2014 Forecast Results Overview

This year, Minnesota Power has identified the "Moderate Growth" scenario as its expected case outlook and has submitted this in its 2014 Annual Electric Utility Report filing. This scenario is similar to last year's submittal and assumes steady underlying growth with new and existing large customers adding about 215 MW by 2020.

Table 1 below shows the Moderate Growth scenario forecast for annual energy sales and seasonal peak demand. Annual energy sales and peak demand are both projected to grow at about 1.1 percent per year (on average) from 2014 through 2028. The large increase in projected sales and demand in the 2015-2016 timeframe is due to the start-up of a new mining customer's facility in Nashwauk, Minnesota.

[1] Both error figures are Mean Absolute Percent Error (MAPE) of the energy sales forecast, and were calculated excluding the recessionary years of 2009 and 2010, in which there's significant and unpredictable fluctuations in large industrial loads.

Table 1: Moderate Growth Energy Sales and Seasonal Peak Demand Outlook

	Total Energy Sales		Peak Demand			
	MWh	Y/Y Growth	Summer (MW)	Y/Y Growth	Winter (MW)	Y/Y Growth
2007	10,680,509		1,758		1,763	
2008	10,839,446	1.5%	1,699	-3.3%	1,719	-3.3%
2009	8,065,090	-25.6%	1,350	-20.6%	1,545	-20.6%
2010	10,417,422	29.2%	1,732	28.3%	1,789	28.3%
2011	10,988,200	5.5%	1,746	0.8%	1,779	0.8%
2012	11,107,358	1.1%	1,790	2.5%	1,774	2.5%
2013	10,985,809	-1.1%	1,782	-0.5%	1,751	-0.5%
2014	11,005,984	**0.2%**	1,727	**-3.0%**	1,772	**-3.0%**
2015	11,455,560	**4.1%**	1,807	**4.6%**	1,931	**4.6%**
2016	12,210,706	**6.6%**	1,923	**6.4%**	1,958	**6.4%**
2017	12,139,526	**-0.6%**	1,941	**0.9%**	1,973	**0.9%**
2018	12,226,004	**0.7%**	1,954	**0.7%**	1,979	**0.7%**
2019	12,282,442	**0.5%**	1,962	**0.4%**	1,988	**0.4%**
2020	12,373,073	**0.7%**	1,970	**0.4%**	1,996	**0.4%**
2021	12,383,656	**0.1%**	1,976	**0.3%**	2,003	**0.3%**
2022	12,428,847	**0.4%**	1,982	**0.3%**	2,010	**0.3%**
2023	12,483,154	**0.4%**	1,990	**0.4%**	2,019	**0.4%**
2024	12,565,416	**0.7%**	1,997	**0.4%**	2,028	**0.4%**
2025	12,587,817	**0.2%**	2,004	**0.4%**	2,035	**0.4%**
2026	12,645,886	**0.5%**	2,011	**0.4%**	2,044	**0.4%**
2027	12,706,022	**0.5%**	2,019	**0.4%**	2,053	**0.4%**
2028	12,802,330	**0.8%**	2,027	**0.4%**	2,063	**0.4%**

Document Structure

This report has been constructed to provide the energy sales and demand forecast for Minnesota Power for the 2014-2028 timeframe. Each section is designed to convey the report requirements per MN Rules Chapter 7610, and give insight into Minnesota Power's forecasting process and results.

Section 1: *Forecast Methodology, Data Inputs, and Assumptions* details the development of customer count, peak demand, and energy sales forecasts. This section contains a step-by-step description of Minnesota Power's forecasting process and details the development of databases and models.

Other information included in Section 1:

- Descriptions of all forecast models used in the development of this year's forecasts, including:
    - Model specifications
    - Model statistics
    - Resulting forecast's growth rates
    - A discussion of each model's econometric merits and potential issues as well as an explanation/ justification of each variable
- Additional steps taken in 2014 to improve the forecast process and product
- Strengths and weaknesses of Minnesota Power's methodology
- All data inputs and sources, including an overview of key economic assumptions
- A description of all changes made to the forecast database since last year's forecast
- A discussion of Minnesota Power's sensitivity to Large Industrial customer contracts
- Minnesota Power's confidence in the forecast

Section 2: *Forecast Results* presents the six forecast scenarios Minnesota Power developed for the AFR 2014 forecast. Each scenario's forecast is the product of a robust econometric modeling process and careful consideration of potential industrial and resale customer load developments. These Industrial and Resale assumptions were organized into scenarios based on the criteria outlined below:

- **Moderate Growth Scenario (AFR 2014 Expected Case):** includes additional loads served by Minnesota Power and its wholesale customers that are likely but not yet certain. This scenario's assumptions were formed through close communication with customers on their planned expansions and utilize any publicly-communicated schedules from prospective customers.

- **Moderate Growth Scenario with Deferred Resale:** includes additional loads served by Minnesota Power and its wholesale customers that are likely but not yet certain. This scenario's assumptions are identical to those in the Moderate Growth scenario except the start of a new mining customer's facility in Nashwauk is delayed by one year. This scenario demonstrates the sensitivity of Minnesota Power's demand and energy outlook to the timing of this prospective customer's start-up.

- **Current Contract Scenario:** includes additional loads served by Minnesota Power and its wholesale customers that are highly likely, i.e. the customer has a signed service agreement or is otherwise bound by contract to change its load.
- **Potential Upside Scenario:** includes specific industrial expansions, in addition to those in the Moderate Growth Scenario, that are plausible within the next five years.
- **Best Case Scenario:** includes specific additional industrial expansions, combined with those in scenarios above and simultaneous stronger national economic growth. These expansions may be in the initial review stages and are the most speculative, occurring at any point in the next 15 years.
- **Potential Downside Scenario:** includes permanent production slowdowns at specific customer facilities within the next five years and slower national economic growth. Projects deemed to be highly likely under moderate economic conditions are delayed, and added later in the forecast timeframe.

This section also includes several sensitivities to identify the range of possible outcomes due to non-economic factors such as extreme weather, disruptive technologies, and non-renewal of customer contracts.

Section 3: *Other Information* presents other report information required by Minnesota law and cross-references the specific requirements to specific sections in this document.

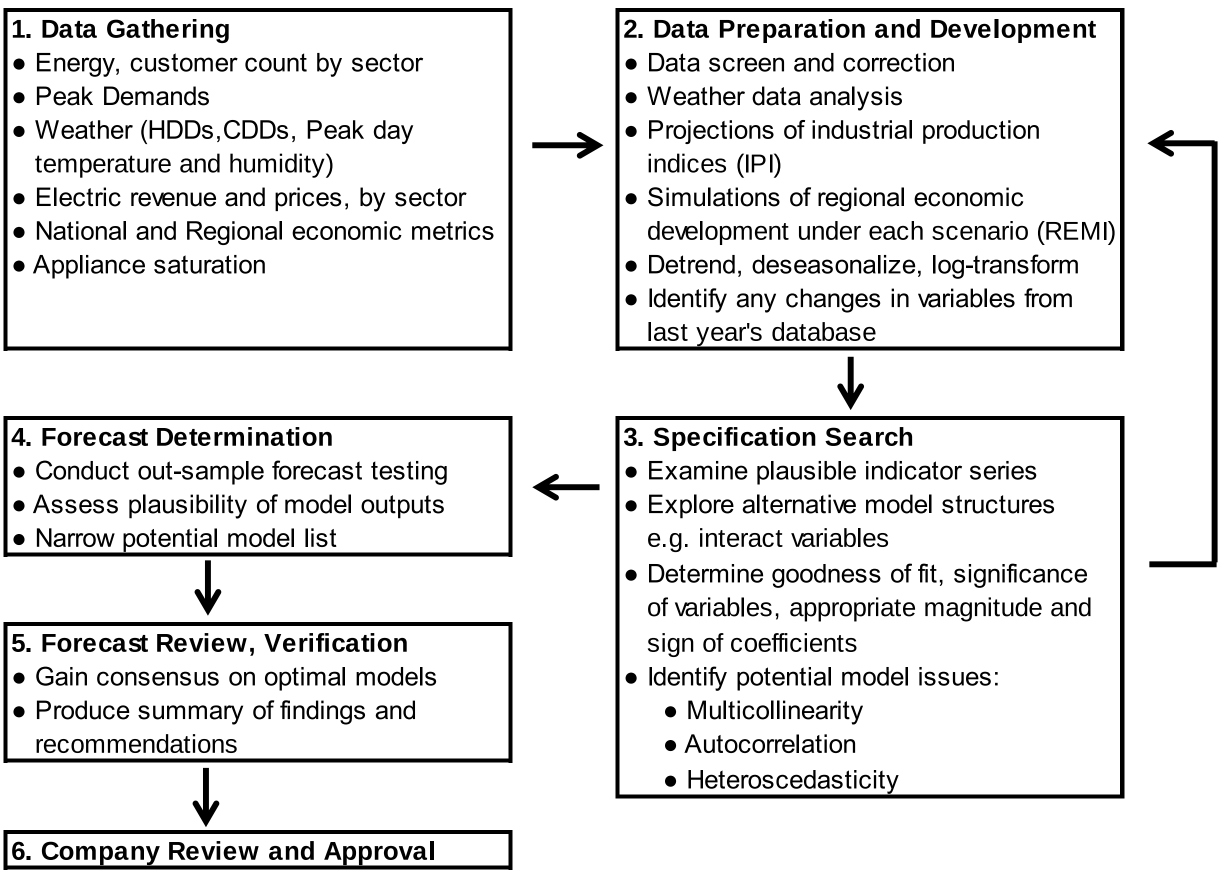
1. Forecast Methodology, Inputs, and Assumptions

A. Overall Framework

Minnesota Power's forecast models are the result of an analytical econometric methodology, extensive database organization, and quality economic indicators. Forecast models are structural, defined by the mathematical relationship between the forecast quantities and explanatory factors. The forecast models assume a normal distribution and are "50/50"; given the inputs, there is a 50 percent probability that a realized actual will be less than forecast and a 50 percent probability that the realized actual will be more than forecast.

The Minnesota Power forecast process involves several interrelated steps: 1) data gathering, 2) data preparation and development, 3) specification search, 4) forecast determination, 5) initial review and verification, and 6) internal company review and approval. The steps of the forecast process are sequential; although, because of the research dimension, the process involves feedback loops between steps 2 and 3. The process is diagrammed in Figure 1 below and discussed in more detail in Section B.

Figure 1: Minnesota Power's Forecast Process



B. Minnesota Power's Forecast Process

i. Process Description

1. *Data Gathering* involves updating or adding to the forecast database. The data used in estimation can be broadly categorized as follows:
   - *Historical quantities of the variables to be forecast,* which consists of energy sales and customer counts for Minnesota Power's defined customer classes, energy sales, and peak demand.
   - *Demographic and Economic data for the 13-County Minnesota Power service territory and Duluth Metropolitan Statistical Area (MSA)* consists of population, households, sector-specific employment, income metrics, regional product, and other local indicators.
   - *Indicators of National economic activity* such as the Industrial Production Indexes or Macroeconomic indicators such as U.S. GDP (Gross Domestic Product) or Unemployment.
   - *Weather and related data* including heating degree days, cooling degree days, temperature, humidity, dew point, and wind speed.
   - *Appliance saturation data* including air-conditioning, electric space heating, and electric water heating.
   - *Electricity and Alternative Fuel prices,* which includes the price of electricity, natural gas, and heating oil by sector for the Minnesota Power service territory.

   After gathering these data, Minnesota Power compares all series to the previous year's database to identify any changes. The cause of any change to the historical data should be explained and justified. This is explained further in Section C: *Inputs and Sources*.

2. *Data Preparation and Development* involves adjusting raw data inputs and then reviewing the data through diagnostic testing. The purpose of this step is to develop consistently defined and formatted data series for use in regression analysis. Adjustments made to specific raw data inputs are described in the "Inputs and Source" section of this document. General data preparation techniques such as *Data Transformation* and *Interpolation* are described in the *Specific Analytical Techniques* section of this document.

3. *Specification Search* involves selecting an appropriate set of variables that serve as explanatory factors for the customer count, energy sales, and peak demand series being modeled[2]. Minnesota Power does this through a formalized two-step modeling and documentation process:

   Preliminary Model Generation – involves systematically generating all models that satisfy a set of basic criteria. Model generation is conducted using a VBA (Visual Basic for Application) tool designed and programmed by Minnesota Power.

[2] Specific analytical techniques applied during this step are detailed in Section D.

The user first identifies the model's basic structure, including: binary variables, trend, verified weather variables, etc. The software then models every combination of economic variables[3] using the specified binary variable structure, and retains all models that meet a predefined set of statistical criteria. This step produced nearly three million plausible regression models[4]. The program then identifies extremely similar models and removes inferior redundancies to reduce the pool of models for consideration to about 220,000 models[5]. All models generated as part of the *Preliminary Model Generation* step of AFR 2014 are archived for later review.

Model diagnosis – involves in-depth analysis of the top 50 models[6] for each dependent variable generated by the *Preliminary Model Generation* process. During model diagnosis, another custom-programed VBA tool is leveraged to calculate and compare the models' critical statistics. At this stage, review of the model results may show an alternative binary variable structure or interaction variable could add value and both *Preliminary Model Generation* and *Model Diagnosis* are repeated. If alternative specifications cannot improve model quality, the process moves on to Step 4: *Forecast Determination*.

During *Model Diagnosis*, Minnesota Power's custom-programed VBA tool identifies the following statistical metrics:

- Goodness of fit: Adjusted R-Squared and MAPE (Mean Absolute Percent Error).
- Model simplicity and efficiency: AIC and SIC[7]
- Heteroscedasticity: Breusch-Pegan F, Breusch-Pegan ChiSq, and White's F tests.
- Multicollinearity: Variance Inflation Factor (VIF) of each input variable
- Autocorrelation: Breusch-Godfrey F & Chi-Squared, Durban-Watson, and Durban-H
- Specification tests of non-linear variable combinations: Ramsey's RESET F
- Out-sample forecast error: RMSE (Root-Mean Squared Error), MAE, and MAPE

4. <u>*Forecast Determination*</u> narrows the list of potential models via a thorough review. Minnesota Power evaluates and compares model statistics, plausibility of the model's outputs (i.e. the forecast), and model structure. This step involves the utilization of objective metrics as far as is possible to inform judgment on the part of the forecaster.

   The forecast determination process begins by identifying the apparent statistically-superior model. If the model's forecast growth rate is implausible or predictor variables are unintuitive, Minnesota Power moves on to the second most statistically-superior model. This continues until Minnesota Power identifies a plausible model. This top-ranked model is then selected as a preferred or preliminary AFR model for the specified dependent variable (customer count, energy sales, peak demand).

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[3] Only two economic variables are modeled at a time because 1) a third or fourth economic variable is unlikely to add considerable predictive value, and 2) three or more variables is computationally intensive.

[4] This figure is the total of all preliminary models generated for all dependent variables.

[5] This figure is the total of all filtered preliminary models generated for all dependent variables.

[6] Models are ranked by a 2-year Out-sample Root-Mean-Squared Error (RMSE)

[7] Akaike information criterion and Schwarz information criterion

However, the difference in statistical quality among top models is usually negligible and there are reasons to dismiss the top-ranked model in favor of a lower ranking model. For example, having a weather variable for each month is ideal because it allows for accurate after-the-fact weather normalization later by the company. If the top-ranked model lacks a specific month's weather variable, it may be passed-over in favor of one that has a full complement of weather variables, and is nearly identical in statistical quality.

This step narrows the model list further; from fifty to just two or three select models for each dependent variable.

5. *Forecast Review and Verification* produces a list containing a single, preliminary model for each of the dependent series. During this step, analysts compare and debate the quality of models to reach a consensus around a final set of optimal models. Where a consensus cannot be immediately reached because two models may be highly comparable in statistical quality and plausibility of outputs, out-sample forecast accuracy determines the model put forward for *Company Review and Approval.*

6. *Company Review and Approval:* All forecasts are vetted internally to ensure that consistent use of forecast information was employed and that the forecasts are reasonable.

ii. Specific Analytical Techniques

Data Transformation Schema for Economic Variables: Transformations are used to maintain consistency among variables or to identify non-linear relationships between predictor variables and the dependent variable within the confines of simple linear regression. Minnesota Power uses several data transformations in data development: constant-dollar deflating/inflating, per-day conversion, de-trending/ de-seasonalizing, first difference, natural log de-trending, and first difference of natural log.

Constant-dollar Deflating/Inflating - is the process of deflating/inflating all dollar-denominated series to the same base year to maintain consistency of definition. Minnesota Power utilized 2009 as its base year in the 2014 forecast. The 2009 base year is the current standard among public and private data providers such as IHS Global Insight and the Bureau of Economic Analysis (BEA).

Per-day Conversion – divides monthly billed energy use or monthly Heating/Cooling Degree Days by the number of days in the specified month. This transformation normalizes for the effect of varying days-per-month on a monthly aggregate like energy use or Heating/Cooling Degree Days. This results in consistently defined series that are more appropriate for linear regression modeling.

De-trend and De-seasonalize – is the process of removing the historical trend/ seasonality from a data series. This reduces the potential for the spurious, or *false*, correlation that often results from mistaking similarity of *trends* with similarity of *variation* between a predictor and the dependent variable.

Natural Log De-trend – takes the natural log (ln) of each observation in the series and then removes the historical trend/ seasonality from the series. This transformation allows a linear regression processes to identify non-linear relationships between variables. For example: a 10 *percent* increase in X causes a 1 *unit* increase in Y.

First Difference – changes the definition of the series from *level* (e.g. the number of customers in a month) to *change* (e.g. the customers gained or lost from one month to the next) by subtracting the previous value from the current. The *first difference* transformation reduces the series to only *variation* (change) so there is no trend of potential to mistake similarity of *trend* with similarity of *variation*.

First Difference of Natural Log – calculates the month-to-month change in the natural log series.

<u>*Interpolation Technique*</u> – Minnesota Power collects and utilizes raw monthly-frequency data whenever possible. However, some data series are not available at a monthly-frequency (e.g. U.S. GDP is only available in Quarterly and Annual frequencies). Interpolation allows annual or quarterly data to be used in monthly-frequency regression modeling by converting it to a monthly variable.

The specific interpolation function utilized in Minnesota Power's 2014 forecast process is known as a "Cubic Spline" interpolation. This technique is widely used because it produces a smooth monthly series by constraining the first and second derivatives of the variable to be continuous on the entire time interval.

The cubic spline interpolation function is in piecewise cubic polynomial form:[8]

$$Y_i(t) = a_i + b_i t + c_i t^2 + d_i t^3$$

Where: $0 \leq t \leq 1$

$i = 1, 2, \ldots, n - 1$

$Y_i = i^{th}$ piece of the spline

a_i, b_i, c_i, and d_i are estimated polynomial coefficients

Annual-to-monthly interpolation assumes the annual value as June, and July through May are interpolated points. Quarterly-to-monthly interpolation assumes Quarter 1 as February, Quarter 2 as May, Quarter 3 as August, and Quarter 4 as November; all other months are interpolated points.

Utilization of a cubic spline function for interpolation is new to the AFR 2014 process and is an improvement over previous interpolation methods. In previous forecasts, Minnesota Power used some variant of a simple "straight-line" interpolation function. The change in the interpolation methods will cause the historical monthly data in the forecast database to differ slightly from the previous years.

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[8] http://mathworld.wolfram.com/CubicSpline.html

Modeling Techniques - As a rule, all models are ordinary least squares (OLS) and all input variables' coefficients must be significant at a 90 percent level (as indicated by p-values less than 10 percent). OLS models are simple, transparent, explainable, and produce optimal estimates of the coefficients. Confidence in the significance of these coefficients is maintained as long as the model is not negatively affected by autocorrelation or heteroscedasticity.

Each dependent variable (14) is modeled in both levels and logs, but is not de-trended. If a trend is present in the historical count or sales data, it should be accounted for with a trend variable. The trend variable explains general, underlying growth, whereas the de-trended or differenced independent (indicator) variables explain variation around this trend.

During the *Specification Search* and *Forecast Determination* steps each model is subject to the criteria below:

1. Test for autocorrelation using:
    a. ACF and PACF Plots
    b. Breusch-Godfrey test - Low p-value (below 5 percent) rejects the initial hypothesis and indicates presence of potentially problematic autocorrelation.
    c. Durban-Watson and Durban-H

    If autocorrelation is present:
    a. Include ARMA[9] terms to solve for autocorrelation and obtain accurate estimates of coefficient's t-stats and p-values
    b. Remove truly insignificant economic variables (as indicated by high p-values). Seasonal binaries, trends, and constants are not subject to this rule because their apparent insignificance results from the ARMA terms appropriating their role in the model and not from autocorrelation
    c. Remove ARMA terms to revert to a corrected OLS model

    ARMA terms are only used to assess or un-bias the P-values of the OLS models. Autocorrelation may still be present in the final OLS, but it's been shown to have minimal impact on model coefficients and has not biased P-values.

2. Test for multicollinearity using VIFs (Variance Inflation Factors) - multicollinearity is generally unacceptable in the final models but is assessed in the context of other variables and model statistics. The VIF of a variable is a measurement of its correlation with every other variable in the model whereas a correlation matrix would only identify the correlation of two variables to each other at each point in the matrix. Thus, VIFs are superior to a correlation matrix as a method of identifying multicollinearity. VIFs are assessed according to these criteria:

    a. VIF less than 3 is optimal - correlation with the remaining variables is less than 82 percent.
    b. VIF of 3-5 is acceptable, but is assessed in context with other diagnostics.

[9] Autoregressive Integrated Moving Average

c. VIF of 5-10 is generally unacceptable, but is assessed in context with other diagnostics. A VIF > 5 implies correlation with remaining variables is greater than 90 percent.
d. VIF greater than 10 is unacceptable correlation for any economic variable. In this case the correlation with the remaining variables is greater than 95 percent.

VIFs on all economic and demographic variables in all models are well within acceptable limits. Minnesota Power considers high VIFs on seasonal binaries variables inconsequential since the cause of this correlation is clear; it's interacting with the intercept, weather variables, or other binaries. Because these binaries are important to the structure of the model, they are not excluded in the same way an economic variable would be if found to have high multicollinearity with other variables.

3. Test for heteroscedasticity using:
    a. Breusch-Pegan F and Chi-squared
    b. White's F tests.

Presence of heteroscedasticity cannot bias the estimates of the coefficients. However, heteroscedasticity can affect the measured standard errors of the estimates, which may bias the estimates of t-statistics and P-values.

When heteroscedastic conditions are present in the preferred OLS model, Minnesota Power follows the same process as with autocorrelation. ARMA terms are added in an attempt to solve heteroscedasticity and examine the unbiased P-values. Occasionally, heteroscedasticity cannot be solved for and plausible alternative models cannot be identified. In these cases, Minnesota Power had no choice but to accept that estimates of P-values in these models may be biased.

Models that meet the above criteria, have plausible outputs (forecasts), and have an intuitive econometric interpretations are put forward as potential final models for review during the *Forecast Determination* and *Forecast Review and Verification* steps (AFR 2014 Forecast Process pg. 5).

Once forecast models are verified and finalized, they form the basis of the "econometrically-determined" outlook for energy sales, peak demand, and customer count. Assumptions for future load additions/ losses and adjustments to account for recent customer expansions are applied to the econometric outlook to produce Minnesota Power's final energy sales, peak demand, and customer count outlook.

iii. Methodological Adjustments for the 2014 Forecast

Minnesota Power is continuously improving its forecast methodologies to better model and predict customer energy requirements. This year's forecast features an expansion of the forecast database, an enhanced *Specification Search* process, and key methodological enhancements.

Adjustment of the Historical Energy Sales and Peak Demand Data to Account for Recent Customer Expansions: To avoid biasing estimates due to structural breaks in the historical timeframe, Minnesota Power removes the impact of recent large load additions/ losses from historical energy sales and peak demand prior to regression modeling. The adjusted series is then modeled, an econometric forecast is produced, and then projected sales to these large customers are added back to the econometric forecast.

In the past, Minnesota Power modeled raw historical sales data and made no adjustments to the raw sales data prior to regression. Instead, post-regression arithmetic adjustments were applied to the econometric forecast to account for large load additions in the forecast timeframe. This is no longer a suitable approach to forecasting given the sizable impact of recent load additions/ losses on the *historical timeframe* used for estimation; there's a high potential for double-counting or understating the impact of recent load additions or losses.

In econometrics, clear definitional shifts affecting the historical series (such as the recent addition of a large customer) are referred to as "Structural Breaks," and, if left unaccounted for, can lead to large forecasting errors and unreliability of the model in general[10].

Ideally, structural breaks are modeled with a binary variable that denotes the sudden break, but this requires abundant observations both before and after the break. Minnesota Power's large additions/ losses are so recent that there are not enough observations for a binary variable to effectively account for any structural breaks. Thus, the only option for avoiding the negative effects of structural breaks is to adjust the historical data. Minnesota Power will evaluate this approach each year and revert to use of raw (unadjusted) data if and when structural breaks can be accurately accounted for using a binary variable.

For consistency of application, a structural break is defined as the addition or loss of a customer that comprises more than one percent of sales to its respective customer class in any given historical year. Adjustments for structural break are only made when metered sales data is available[11]. These adjustments are described in detail in the *Data Revisions Since Previous AFR* section.

Use of Binary Variables Account for Shift in Customer Count Growth: Since the recession, Minnesota Power has observed a divergence of economic indicators and energy sales. Although economic conditions have improved, employment has rebounded, and population growth in the region has resumed, there has been little to no growth in electricity use by several customer classes.

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[10] Structural Breaks should not be confused with sizeable shifts that results from a measurable change in the economy. For example: The change in the composition of the Mining and Metals sector due to the closing of LTV, while sudden and sizeable, had a clear economic cause and economic metrics can be used to accurately model this loss of energy sales and load.

[11] Minnesota Power has a number of resale customers that have experienced recent load additions and losses, but these data are not available to Minnesota Power. In this case, a post-regression adjustment is still applied to account for the load addition in the forecast timeframe. When it's evident that this load addition or loss is reflected in the econometric forecast, Minnesota Power will cease the post-regression adjustment.

For example, Residential customer count has grown by just 97 customers or 0.08 percent (net) since 2009 and sales have stagnated as well. However, key economic and demographic indicators continued to grow in this timeframe. A model using these indicators would over-forecasts in the later years of the estimation timeframe (2012-2013) and, presumably, the first period in the forecast timeframe (2014). To account for this divergence, Minnesota Power utilizes binary variables in several customer count models to effectively shift the first forecast year (2014) to align with the last historical year (2013). Although the forecast is shifted by the binary viable (a constant), the trajectory (growth rate) of the forecast is still determined by the economic variables.

Refined Temperature Range Stratification Approach (Peak Demand Model): Last year, Minnesota Power adopted a stratified temperature variable approach to better estimate temperature's impact on demand ("weather effect"). This approach involved stratifying temperature variables according to temperature range rather than by month (via a *Monthly Interaction*). This weather variable specification improved the significance of coefficients and prevented some statistical issues such as multicollinearity; however, the specific method of stratification created variables that were not mutually exclusive, which complicated the interpretation of the coefficient.

This year, each temperature series (high, low, and average temperature for the day) is stratified based only on the average temperature for the day. Stratification based on a single series produces mutually exclusive variables and eliminates the possibility for overlap to clarify the definition/ interpretation of the coefficients.

For consistency with this change, the temperature humidity index and the wind chill index are also based on the average temperature for the day.

iv. Treatment of Demand-Side Management (DSM) and Conservation Improvement Programs (CIP)

DSM programs represent activities that a utility undertakes to change the configuration or magnitude of the load shape of individual customers or a class of customers in the interest of reducing environmental impact and postponing construction of new capital.

Minnesota Power has engaged in several different types of DSM:

- *Conservation* - Conservation results in a reduction in total electric energy consumed by a customer and the potential to reduce both on-peak and off-peak demand. Conservation generally results in a reduction in the overall rate of growth of electric energy demand. Conservation, in the context of Minnesota Power conservation programs, may also include process efficiency, which results in the potential to reduce the total electric energy consumed by a customer as well as to decrease on-peak and/or off-peak demand. Process efficiency reduces the overall growth rate of electric demand because it results in greater production, through more efficient equipment or processes, from a facility for the same energy inputs. If the facility failed to implement process efficiency projects, more electric energy would be required to meet production requirements. Process efficiency generally results in avoided energy production and capacity additions over the long-term.

- *Peak Shaving* - Peak shaving reduces peak demand without affecting off-peak demand. Minnesota Power's dual-fuel load control and Large Power (LP) interruptible programs are peak shaving programs.

- *Load Shifting* - Electric demand is shifted from on-peak to off-peak hours.

Minnesota Power excluded any exogenous DSM/CIP data adjustment to the energy sales and demand forecasts. The impact of conservation and DSM/CIP programs are present in the historical data upon which all AFR 2014 models were constructed, and are therefore implicit in the forecasts. An exogenous adjustment on top of the embedded impacts will double count the effects of conservation and misstate energy consumption.

v. Methodological Strengths and Weaknesses

Minnesota Power's forecast process combines econometric modeling with a sensible approach to modifying model outputs for assumed changes in large customer loads. An econometric approach, utilizing regression modeling, is optimal for estimating a baseline projection with a given economic outlook. However, a fully econometric process would not imply any of the substantial industrial expansions that are likely in the Minnesota Power service territory. A combined "econometric/ large customer load addition" approach produces the most reasonable forecast.

Minnesota Power's econometric modeling process has two key strengths; it's both highly replicable, and adept at narrowing the list of potential models to only those that are most likely to produce quality results which allows more time for in-depth statistical testing and critical review of each model.

That said, there are some weaknesses to a combined "econometric/ large customer load addition" approach. For instance, there is some subjectivity in the perceived likelihood of individual large customer load addition/ losses since their magnitude or timing is difficult to estimate in a probabilistic way. To minimize subjectivity on the part of Minnesota Power, the Company utilizes any information that has been publicly communicated by prospective customers in its scenario planning.

Minnesota Power is highly sensitive to large industrial customer decisions as large taconite, paper, and pipeline customers represent more than half of Minnesota Power's system demand and energy sales at any given point in time. Minnesota Power addresses this potential for error by maintaining close contact with existing and potential customers to identify their plans, and then creating a range of plausible scenarios to address the uncertainty.

C. Inputs and Sources

Minnesota Power draws on a number of external data sources and vendors for its indicator variables. Each year, the forecast database is updated with the most current economic and demographic data available. This involves an update of the entire historical timeframe since these data are frequently revised. Special attention is given to identifying any changes from previous years' data and data sources. Changes from last year's database are clarified later in this section.

i. AFR 2014 Forecast Database Inputs

<u>Weather</u>

Weather data for Duluth, MN was collected for historical periods from the National Oceanic and Atmospheric Administration (NOAA) and from Weather Underground (WU)[12]. Minnesota Power utilizes Monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) in energy sales forecasting and peak-day weather conditions in peak demand forecasting.

Monthly total HDD and CDD are sourced from NOAA. The monthly total HDD and CDD values are normalized for the number of days in a month by dividing the monthly HDD or CDD count by the number of days in the month. This result in the "per-day" series HDDpd and CDDpd. For example:

The "per-day" value of 46.1 HDDpd in January 1990 was calculated as follows:

> Duluth Minnesota's HDD count for January 1990 (1428) is divided by the number of days in January (31) to produce an HDDpd value of 46.1.

Normalizing the series by transforming to a per-day unit allows for a more accurate estimate of the weather's impact on energy sales. The forecast assumes a 20-year historical average for each month (Apr 1994 – Mar 2014). January's forecast assumption (for example) is an average of Jan-95, Jan-96,…, Jan-14.

Temperature, humidity, and wind-chill data used to model peak demand are derived from WU. This source has been in use for daily-frequency weather data over the last two forecasting cycles instead of NOAA data. WU's weather data rarely differs from NOAA, and the WU online tools and data format are more conducive to variable development.

Development of the historical weather series begins by establishing the date of historical monthly peaks. Weather data for these dates is then gathered and organized into monthly-frequency peak-day weather series.

Calculating a 20-year historical average of peak-day weather for use as a forecast assumption requires recorded peak dates for the timeframe prior to the establishment of the current electronic

[12] http://www.wunderground.com/

database (1994-1999). Minnesota Power uses the Federal Energy Regulatory Commission (FERC) Form 1 to identify the dates for peaks prior to 1999 and then gathers the corresponding weather data. Forecast assumptions for peak-day weather can be calculated from the completed 20-year history.

A Temperature-Humidity Index[13] (THI) is utilized to take into account the effect of heat and, when applicable, humidity on summer peaks. The THI is only applicable when temperatures exceed 80 degrees and relative humidity exceeds 40 percent. If both conditions are not met, humidity's impact is assumed to be minimal and is excluded. A Wind-chill index[14] (WC) was also utilized to capture the cold temperatures and, when applicable, the cooling effect of wind speed.

IHS Global Insight

Since 2009, Minnesota Power has utilized IHS Global Insight estimates of historical and forecast economic activity in Northeast Minnesota[15] as key inputs to energy and customer count models. This year's forecast process features an expansion of IHS Global Insight data use.

Duluth Metropolitan Statistical Area (Duluth MSA)[16] economic indicators were added to the forecast database, along with the 13-County economic indicators. The more geographically-granular indicators were expected to add predictive power by more closely aligning with the area containing Minnesota Power's customer base. This database expansion also simply adds to the pool of potential predictor variables during modeling.

National-level economic indicators from IHS Global Insight replace Blue Chip Economic Indicators[17] as inputs to Industrial Production Index (IPI) modeling. IHS Global Insight provides access to more national-level variables and allowed Minnesota Power to expand the IPI forecast database. The data source change also maintains consistency of assumption in all areas of Minnesota Power's forecast process and among all levels of geographic granularity.

IHS Global Insight County-level data for Northeast Minnesota[13] is calculated through a "Top-down/ Bottom-up" approach; the Minnesota Power area economy is modeled independently, considering unique local conditions, and is then linked to the national economy to ensure consistency across the national, regional, state, and MSA levels. IHS Global Insight utilizes the most current historical data available from public data sources, which is updated frequently. These updates flow through IHS Global Insight's process to ultimately effect historical series used in Minnesota Power's forecast database. Thus, the historical regional employment and income data has changed from last year's database.

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[13] http://www.srh.noaa.gov/images/ffc/pdf/ta_htindx.PDF
[14] http://www.nws.noaa.gov/os/windchill/index.shtml
[15] Minnesota Power's 13-County Planning Area is defined as: Carlton, Cass, Crow Wing, Hubbard, Itasca, Koochiching, Lake, Morrison, Pine, Saint Louis, Todd, and Wadena counties in MN, and Douglas county WI
[16] The Duluth MSA is defined as St. Louis Co. MN, Carlton Co MN, and Douglas Co. WI
[17] Blue Chip Economic Indicators was the only source of national economic indicators used in previous forecasts

The frequency of the raw Duluth MSA and National-level economic data is quarterly, and interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

Regional Economic Models, Inc. (REMI)

Minnesota Power subscribes to the latest REMI Policy Insight version (PI+) for northeastern Minnesota. This input/output econometric simulation software combines a national economic outlook[18] with specified regional economic conditions to produce a forecast for a 13-County Planning Area such as employment by sector, population, economic output by sector, and gross regional product (GRP).

For the 2014 AFR, REMI was used to quantify the indirect economic effects of known and expected changes in regional employment (i.e. expansions and layoffs/ closures) to produce an expected economic outlook for the region.

Minnesota Power also simulates alternative regional outlooks utilizing different employment scenarios; each employment scenario corresponds to a forecast scenario. The forecast scenarios described in Section 2 of this document are developed in two ways: 1) direct, post-regression load adjustments to the econometric output, and 2) indirect, simulated economic impacts incorporated through the predictor variables. Utilization of REMI to develop these economic impacts for each scenario allows Minnesota Power to maintain consistency of assumption across customer classes.

IHS Global Insight economic indicators for both 13-County Planning Area and the Duluth MSA are calibrated using the results of REMI's economic simulations. As the REMI outlook is adjusted for alternative planning scenarios, the monthly employment and income outlooks are changed accordingly.

Some indicators such as population and Gross Regional Product are not provided by IHS Global Insight Inc. for the 13-County Planning area. These series are derived directly from REMI outputs, and are of annual frequency. Interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

Like IHS Global Insight, REMI relies on data from public sources that is subject to revision. These revised data inputs result in revised historical values for the economic and demographic indicators used in Minnesota Power's database.

Indexes of Industrial Production (IPI series)

The indexes of industrial production are measures of sector-specific production in a given month relative to a base year, 2007 in this case (that is, 2007 = 100). The indexes exhibit a high degree

[18] Prior to simulation, REMI is calibrated to the IHS Global Insight National Economic Outlook

of correlation with Minnesota Power's historical industrial energy sales and are therefore ideal for forecasting future energy sales to the class.

The historical IPI data were obtained from the Board of Governors of the Federal Reserve. The historical data is regularly revised to incorporate better data, better methods, and to update the base year. To capture these revisions, Minnesota Power updates the entire historical data series each year. These revisions are explained on the Federal Reserve's website[19].

Forecasts for each IPI were developed from the projections of National-level economic indicators from IHS Global Insight, and are therefore consistent with all other AFR 2014 forecast assumptions. These macroeconomic drivers are used model and forecast the IPI series.

Minnesota Power de-trends and de-seasonalizes all input variables prior to modeling and opted to utilize an already de-seasonalized series from the external source rather than applying its own de-seasonalizing function. Both the seasonally-adjusted and unadjusted series are available from the Board of Governors of the Federal Reserve. The 2014 forecast database utilizes the seasonally adjusted historical indexes whereas last year's AFR used the un-seasonally adjusted series. Differences between the seasonally-adjusted and unadjusted series at the annual level are very small.

Energy Prices

Estimates of future Minnesota Power rate changes are incorporated into the average electric price forecasts as generally indicative of the intention and anticipation of changes in Minnesota Power's rate structure and prices.

Average energy prices, history and forecast data, are from the Department of Energy (DOE) and Energy Information Administration (EIA). The fuel types considered are electricity and natural gas. End-use class energy price data is categorized by DOE/EIA into residential, commercial, and industrial. DOE's Annual Energy Outlook (AEO) is used for the forecast period. DOE provides historical energy price data for Minnesota, forecast energy price data for the West North Central (WNC) region, and the national total. Minnesota Power's historical average electric price data are from the Company's FERC Form 1 and represent annual class revenue divided by annual class energy. All energy prices are deflated by the 2009 base year GDP implicit price deflator (IPD).

Appliance Saturation

Residential appliance saturation rates are key determinants of residential energy use. Minnesota Power leverages customer survey data, EIA survey data, and key economic indicators to approximate the level of historical and forecast appliance ownership. Historical Central Air Conditioning, Electric Space Heat, and Electric Water Heat ownership rates were constructed from survey respondents' answers regarding age of appliances, dwelling age, etc. Forecasts of appliance saturation rates are produced by modeling the historical series using economic and demographic indicator variables such as Duluth MSA Housing Starts.

[19] http://www.federalreserve.gov/releases/g17/revisions/Current/g17rev.pdf

ii. Data Revisions Since Previous AFR

Minnesota Power made a number of adjustments to internally developed data for the 2014 AFR, which fall into four general categories:

1. Revisions of count, sales, and peak demand data
2. Adjustments to raw customer count data for billing anomalies
3. Adjustments to raw sales and peak demand data for large load additions and losses
4. Revision of customer appliance saturation rate estimates

Revisions of count, sales, and peak demand data - Constructing a monthly-frequency database for an extensive historical timeframe requires reconciliation of different records and data sources. Billing practices and customer class composition change over time, and sources occasionally disagree or differ in definition. Minnesota Power reviews and revises its forecast database each year if inaccuracies are identified. Only three substantive (more than a rounding error) changes were identified:

Change #1 – Energy sales to Mining customers in 2000 were lowered by about 55,000 MWh (1.2 percent) and sales to Other Industrial customers were increased by this amount. Total Industrial energy sales were unchanged. Two customers [**Trade Secret Data Excised**] were incorrectly classified as mining customers in Minnesota Power's historical records for this year. The difference in customer class composition was corrected. This small, isolated adjustment had minimal effect on the forecast.

Change #2 – The historical sales series for each industrial sector (Mining, Paper, Other) was limited to 1996. In previous AFR databases the data extended to 1994. Post-1996 data is of higher quality and customer-level detail is available so class composition can be verified. Pre-1996 data does not have this level of detail and class composition could not be verified; it was therefore excluded from the forecast database.

Change #3 – The historical count of lighting customers was reduced in the 2009-2013 timeframe by about 1000 per year. Minnesota Power changed billing practices in mid-2009 to count each service point as its own customer; this expanded the customer count by an unmanageable 2500 percent. For the 2014 AFR database, Minnesota Power used the old billing practices to identify and revise lighting customer counts in the 2009-2013 timeframe to create a constantly-defined series that can be accurately forecasted.

Adjustments to raw customer count and energy sales data for billing anomalies – Minnesota Power's historical customer count and energy sales data contain a number of anomalous or missing observations that can affect modeling and resulting forecasts.

Employing a binary variable during modeling or adjusting the raw data prior to modeling are two common techniques used to avoid biasing models with anomalous observations. In previous years, Minnesota Power used both techniques, but their application was not entirely consistent. The 2014 database policy is as follows:

Where there is a systemic shift (e.g. seasonal billing in residential customers count), Minnesota Power does not adjust the raw data and instead utilizes a binary variable in modeling. When there are less than 3 consecutive anomalous observations, Minnesota Power adjusts the raw data prior to regression using straight-line interpolation. In general, an observation was considered anomalous if it varied by more than 0.5 percent from a straight-line-interpolated value.

The 2014 customer count and energy sales database contains 115 monthly points (about 2.4 percent of all monthly points) that have been adjusted in this way.

Adjustments to raw sales and peak demand data to account for large load additions and losses – All adjustments to the historical database are described below in detail and organized by sector. The impact of this methodological change on the forecast for each customer class is discussed in the *Model Documentation* section.

[Trade Secret Data Excised]

Revision of customer appliance saturation rates – Air-conditioning and electric heat ownership are estimated based primarily on survey data. In recent years, Minnesota Power has used economic and demographic indicators to refine its estimations of historical saturation rates, and has been able to improve the predictive ability of weather variables as a result. This year, Minnesota Power leveraged survey results from the EIA for several geographic regions[20] to test and improve its historical estimation method. This had the effect of increasing Air-conditioning saturation in the early historical timeframe (1990-2003) by about 3 percent per year and reduced saturation in the later historical timeframe (2004-2013) by about 2 percent per year. Electric heat saturation was increased by about 2 percent per year in the years 1990-1998 and 2007-2013, and was reduced by about 2 percent per year in the 1999-2006 timeframe.

Regarding externally derived data, Minnesota Power noted several small changes between the AFR 2014 forecast database and the AFR 2013 database. None of the changes are unexplainable or implausible, and Minnesota Power is confident in moving forward with the database updates. Table 2 shows the series that were utilized in both the AFR 2013 and the AFR 2014 forecasts.

Table 2: Changes to Forecast Database

Economic and Demographic Variables	Changes to Database 2013 to 2014
MP Area Population	Change #1
MP Area Employment in Education and Health	Change #2
MP Area Employment in Manufacturing	Change #2
MP Area Employment in Trade, Transport, Utilities	Change #2
MP Area Employment in Finance	Change #2
MP Area Employment in Public Sector	Change #2
MP Area Employment in Construction, Natural Resources, and Mining	Change #2
MP Area Wage Disbursements	Change #3
Industrial Production Index: Iron Ore Mining	Change #4
Industrial Production Index: Paper	Change #4
Central Air Conditioning Saturation	Change #5
Electric Heat Saturation	Change #5

Change #1 (Minnesota Power Area Population) – Annual data for the post 2010 timeframe was updated by REMI per updates to other economic and demographic series used as inputs in the REMI model. Population in years 2011 and 2012 were reduced by about 6,000 (1 percent) and 9,000 (1.6 percent), respectively. Differences in the Population variable in the pre-2010 timeframe are due to the use of an alternate interpolation technique as noted in the *Specific Analytical Techniques* section.

[20] Very Cold/ Cold climate region, West North Central census region, Midwest census division, and the entire U.S.

Change #2 (IHS Global Insight Employment Data) – When aggregated to annual values, the income and employment series show minimal variation from the last year's historical data. Differences in employment series prior to 2011are fairly small. The largest difference was in 2010 financial sector employment, which was about 0.5 percent lower in the AFR 2014 database than it was in the AFR 2013 database. All historical data utilized in the forecast database was provided by IHS Global Insight and was not adjusted by Minnesota Power in any way.

Change #3 (IHS Global Insight Income Data) – For consistency with all other dollar denominated series in this year's forecast database, Area Wage and Salary Disbursements was deflated to 2009$. In AFR 2013, this series was denominated in 2005$. Utilization of a different base year (2009$ instead of 2005$) is a simple constant transformation and cannot substantively affect regression results.

Change #4 (Industrial Production Indexes) – As noted in the *Inputs and Sources* section, Minnesota Power transitioned to a seasonally adjusted series from an un-seasonally adjusted series. Historical Industrial Production Indexes (IPI) series were downloaded from the Federal Reserve Board's Data Download Program and were not adjusted by Minnesota Power.

Generally, the seasonal adjustment had the effect of increasing the index in quarter 1 of each year and reducing the index in quarters 2-4. Adjusting for seasonality had almost no impact when the series are aggregated to an annual frequency. There was little to no change in the Iron IPI in all years except in 2009 where the annual values differ by about 1.5 percent. The Paper IP index was unchanged at any significant decimal place.

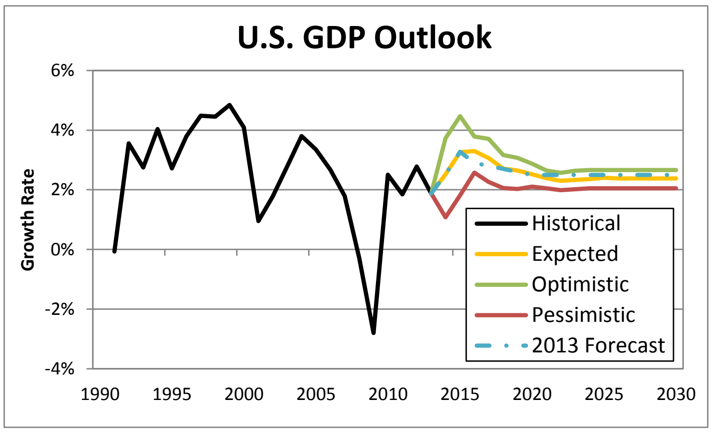
Temperature variables used in the peak demand model have been redefined and will therefore differ from those in last year's database. This change is described in the *Methodological Adjustments for the 2014 Forecast* section because it's not necessarily a revision of historical data; the method of incorporating this indicator variable into the forecast model has been adapted but is still based on the same historical temperature data for Duluth, MN.

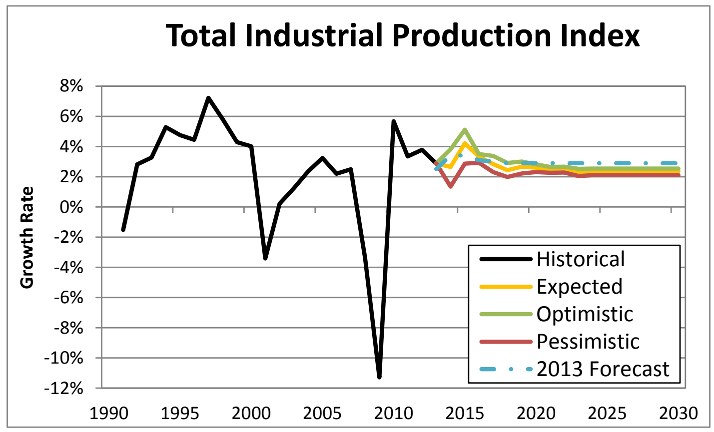
D. Overview of Key Inputs/Assumptions

i. National Economic Assumptions

The national economic outlook is derived from IHS Global Insight and serves as the basis for Minnesota Power's regional economic model simulations. Some of the key outputs of the national economic forecast are GDP, IPI, unemployment rates, and auto sales. These variables are shown in Figures 2-5 below, for the Expected, Optimistic, and Pessimistic cases.

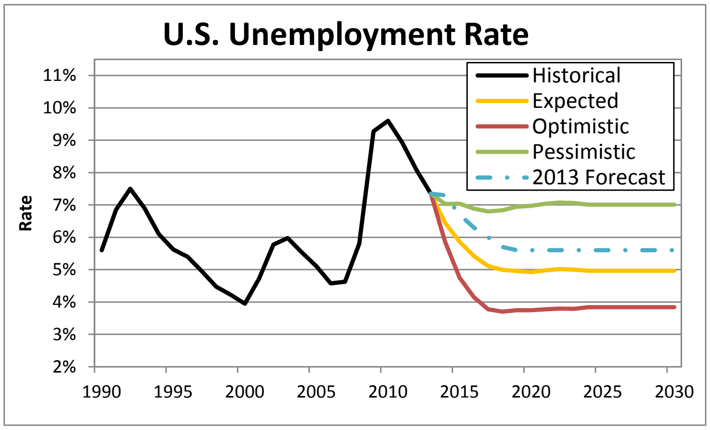
Figures 2 and 3: National Economic Outlook (GDP and Industrial Production)





In the Expected case, U.S. GDP and IPI growth average 2.6 percent per year from 2014-2028. The Expected case (yellow) macroeconomic outlook serves as the underlying assumption for the Current Contract, Moderate Growth, and Potential Upside scenarios. The Pessimistic case macroeconomic assumptions serve as the basis for the Potential Downside scenario; in this case, GDP growth averages just 2 percent per year and IPI growth averages just 2.2 percent per year in the forecast timeframe. The Optimistic macroeconomic outlook drives the Best Case scenario; in the Optimistic outlook GDP and IPI growth average 3.0 percent per year.

Figures 4 and 5: National Economic Outlook (Unemployment Rate and Auto Sales)



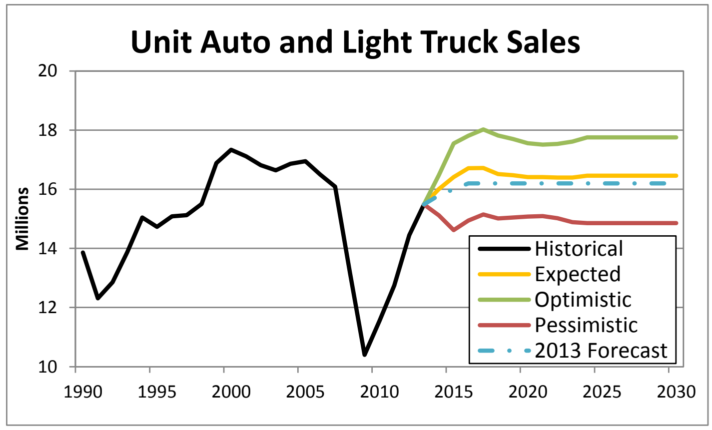
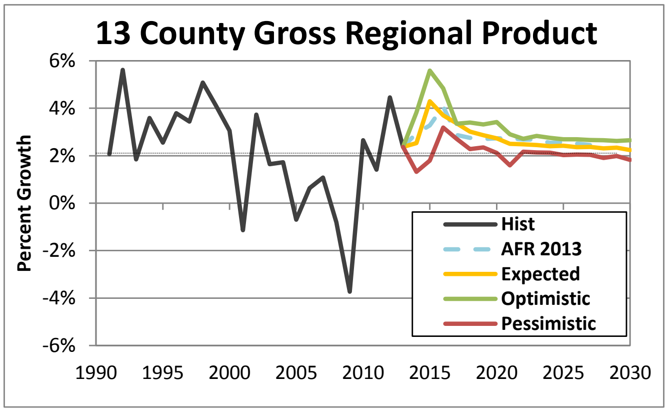


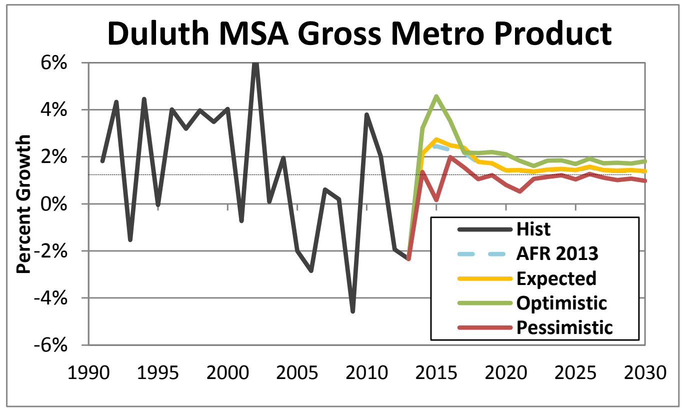
Figure 4 show the unemployment rates in the three national outlooks all fall steadily in the first few years of the forecast timeframe before reaching long term labor market stability consistent with the assumed rate of GDP growth. Assumptions of unit auto and light truck sales in Figure 5 show similar pattern in the forecast timeframe with substantial improvement in the medium-term and stabilization in the long term.

ii. Regional Economic Assumptions

The Regional Economic Model provided by REMI is calibrated to the geographic area additively defined as 13 counties, 12 counties in Minnesota (Carlton, Cass, Crow Wing, Hubbard, Itasca, Koochiching, Lake, Morrison, Pine, Saint Louis, Todd, and Wadena) and one county in Wisconsin (Douglas). This is referred to as the “13-County Planning Area.” Minnesota Power expanded its database to include economic and demographic indicators at the Metropolitan Statistical Area level (this includes St. Louis and Carlton counties in Minnesota and Douglas county Wisconsin). The graphs below show alternative economic outlooks for both regions based on the, high, and low outlooks for the nation. The regional economic outlooks are further specified by incorporating scenario-specific inputs into REMI, as described in Section 1.C. Figures 6 and 7 compare the historical and projected growth rate of both regions’ product.

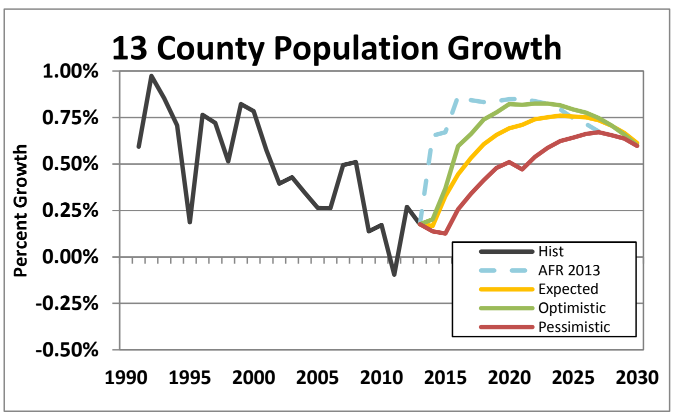
Figures 6 and 7: Regional Economic Outlooks (13-County Product and Duluth MSA Product)

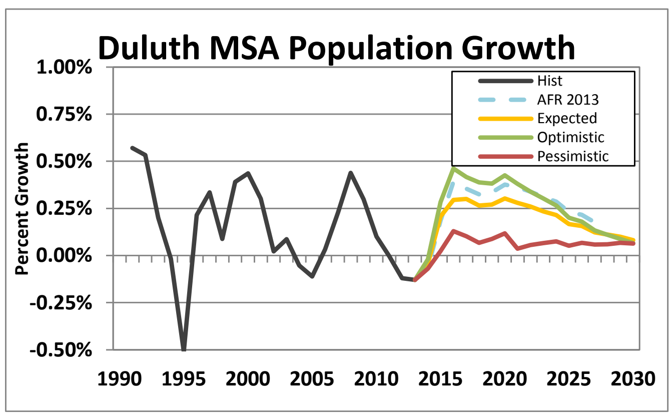




The 13-County Planning Area's Gross Regional Product (GRP) averages 2.7 percent per year growth in the forecast timeframe whereas the Duluth MSA product averages just 1.5 percent per year in the forecast timeframe. Population growth rates show a similar trend: the 13-County Planning Area grows at about 0.6 percent in the forecast timeframe and the Duluth MSA area population grows at just 0.2 percent per year. The difference in the two regions' historical and projected growth, shown below in Figures 8 and 9, demonstrates why Minnesota Power expanded its database.

Figures 8 and 9: Regional Economic Outlooks (13-County Population and Duluth MSA Population)





E. Econometric Model Documentation

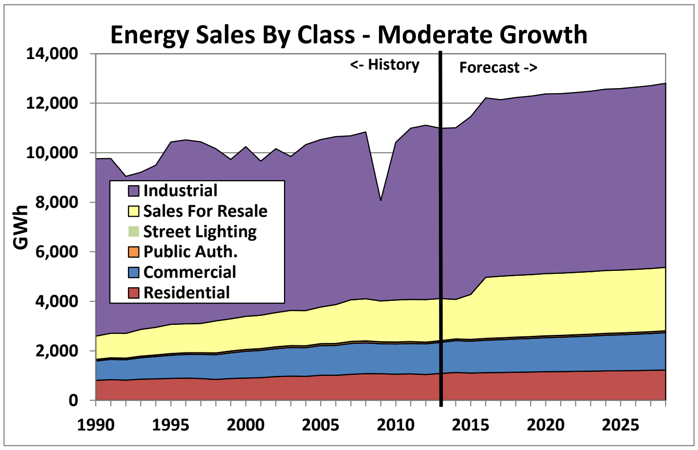
This section presents the statistical detail of all models utilized in the development of the AFR 2014 forecast. The model's structure, key diagnostic statistics, forecast results, and a discussion of the model are provided for added transparency.

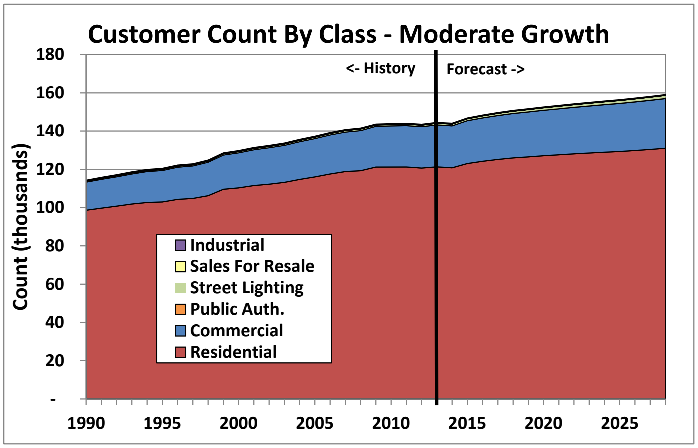
Models are shown with each variable's coefficient, t-stat, p-value, and VIF. A graph displays the historical series, growth rates for time-frames of interest, and compares this year's forecast to last year's forecast. A table shows a more focused view of the forecast with a shorter historical timeframe to examine year-over-year growth rates. Key diagnostic statistics for both the final OLS model and its ARMA-corrected corollary are shown in a table in the bottom left corner of each page. Specific diagnostic criteria and modeling techniques discussed in this section are described in detail in Section B. Minnesota Power's Forecast Process under the heading *Specific Analytical Techniques.*

Minnesota Power offers a discussion of the modeling approach, econometric interpretations of key variables, and potential model issues for each model. This portion of the model documentation also compares this year's model with last year's model and notes any interesting findings or insights gained.

All forecast values shown in this section are the 2014 expected case "Moderate Growth" scenario. The forecast values shown in the chart and tables for each model combine the econometric output with specific load, energy, and customers count additions. The total energy sales outlook is shown below (left) with the total customer count outlook (right).

Figures 10 and 11: Moderate Growth Scenario Projection of Energy Sales and Customer Count by Class





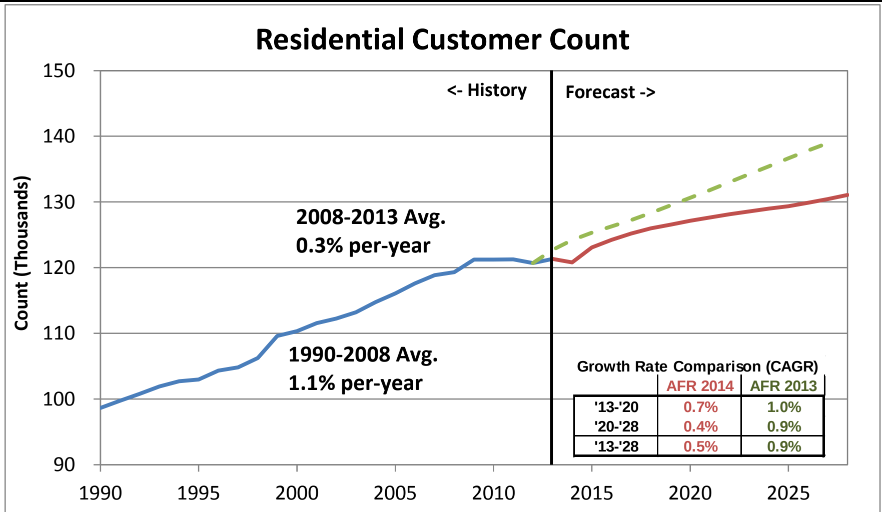
Minnesota Power did not develop a model to forecast Sales for Resale customer count. Minnesota Power currently has 17 resale customers, each of which has signed a service agreement. The loss or gain of a resale customer is therefore better accounted for by reviewing these agreements and communicating with customers. Econometric models are not appropriate for estimating future resale customer counts.

Residential Customer Count - Moderate Growth

Estimation Start/End:	7/1990 - 3/2014
Unit Modeled/Forecast:	Monthly Customer Count

	OLS Model			ARMA Test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	67,222.98	0.00%		0.00%
Trend	92.57	0.00%	2.09	0.00%
Binary_Billing_1	(2,214.61)	0.00%	1.24	0.00%
Binary_Billing_2	(3,420.87)	0.00%	1.46	0.00%
Binary_2012	(925.69)	0.00%	2.04	15.55%
Binary_2013	(2,116.80)	0.00%	2.10	14.07%
Binary_2014-2030	(2,704.59)	0.00%	1.34	12.62%
13co_Edu_Health_lead_6	0.57	0.00%	2.65	0.99%
MSA_Retail_Trade_lag_6	689.62	0.00%	2.11	9.87%

	OLS Model	
	Count	Y/Y Growth
2007	118,870	
2008	119,300	0.4%
2009	121,217	1.6%
2010	121,235	0.0%
2011	121,251	0.0%
2012	120,697	-0.5%
2013	121,314	0.5%
2014	120,818	**-0.4%**
2015	123,065	**1.9%**
2016	124,243	**1.0%**
2017	125,202	**0.8%**
2018	125,997	**0.6%**
2019	126,542	**0.4%**
2020	127,136	**0.5%**
		5 yr CAGR
2025	129,353	***0.3%***



Model Discussion

The AFR 2014 forecast of residential customer count growth moderated due to persistently low growth in the recent historical timeframe. Key economic drivers of customer growth include Employment in the Education & Health sector (13 county) and Employment in Retail Trade (Duluth MSA). This differs from last year's model which utilized Area Households (13 county) as the sole economic driver of customer count growth. Nearly all of the top models for residential customer count contained Employment in the Education and Health sector, which affirms this model's selection.

Minnesota Power's econometric interpretation of the key drivers is as follows: For each job added to the Education & Health sector, the customer count should increase by about 0.57. For each job added to the Retail Trade sector, the customer count should increase by about 0.69 (note that this variable's unit was in Thousands, so the coefficient should be divided by 1,000 to reveal the level impact on count). These impacts are in addition to a general upward trend over time. These variables are plausible and intuitive. Retail Trade employment seems to indicate the variation around the more prominent underlying growth trends indicated by Education and Health employment.

Education and Health sector accounts for 20% of the 13 county planning area employment and has been a strong driver of overall employment growth in the area. From 2000 to 2013, the 13 county area has seen total non-farm employment grow by approximately 5,000. Employment in Education and Health has grown by about 15,000; this more than makes up for substantial losses in Construction, Natural Resource Extraction, and Manufacturing. Employment in Retail Trade at the Duluth MSA level has declined about 1,500 since 2000, but its periods of growth and contraction correlate well with periods of customer growth or stagnation.

Binary variables for 2012, 2013, and 2014-2030 effectively shift the first forecast year (2014) to align with the last historical year (2013). Without these corrective binary variables, a small but growing divergence between actual and predicted customer growth in the late historical timeframe suggests the economic indicators alone would overstate customer count, and the 2014 forecast values from models without corrective binary variables confirm this. Without these binary variables, the model would project an increase of over 2,000 customers from 2013 to 2014 (a 1.5% increase). The corrective binary variables shift the forecast down to avoid improbable increases in customer counts, but do not impact the forecast trajectory; this is determined by the economic variables.

Two binary variables (Binary_Billing) account for seasonal billing between 1994 and 2001. Due to accounting practices, during this timeframe the recorded customer counts from November to May are 2,000-6,000 lower than from June to October. Last year's residential customer count model also utilized these variables.

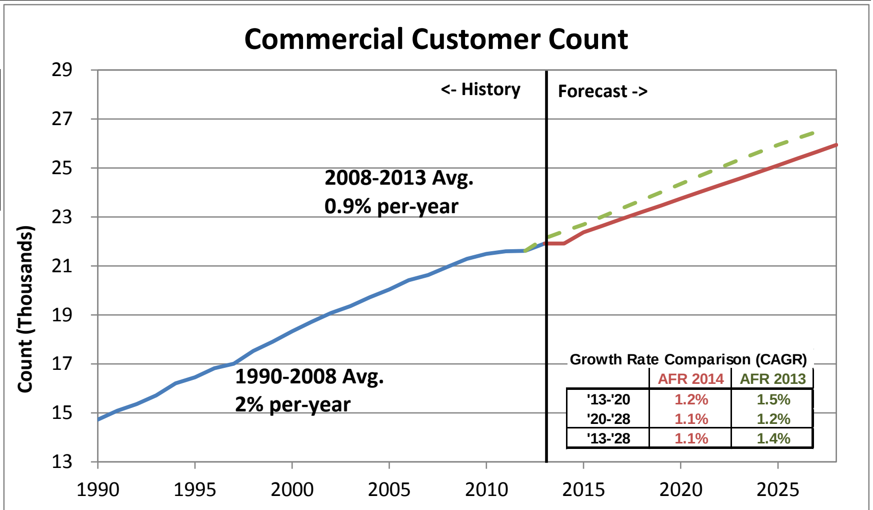
This year's model reduced out-sample forecast error (MAPE) to 0.43% from 0.57% in last year's model and improved other key metrics such as SIC, R-Squared, and in-sample forecast error (traditional MAPE). ARMA testing of the OLS model was able to resolve heteroskedasticity and autocorrelation to confirm the significance (P-values) of the economic variables' coefficients. The very low VIF of each variable proves there is no significant multicollinearity.

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	99.8%		99.9%	
AIC	11.90		11.41	
SIC	12.01		11.57	
MAPE	0.3%		0.2%	
Model F Test	15543.7	0.0%	18519.5	0.0%
Estimates Residual S.D.	377		295	
SSres	39,224,856		23,703,886	
Degrees of Freedom	276		273	
Breusch-Pegan F	3.1	0.2%	1.5	15.2%
Breusch-Pegan ChiSq	23.7	0.3%	12.0	15.2%
White's F	8.9	0.0%	2.2	11.0%
Breusch-Godfrey AIC F	74.5	0.0%	0.5	46.2%
Breusch-Godfrey AIC ChiSq	100.2	0.0%	10.6	0.1%
Breusch-Godfrey SIC F	74.5	0.0%	0.5	46.2%
Breusch-Godfrey SIC ChiSq	100.2	0.0%	10.6	0.1%
Durban-Watson	1.0		2.0	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	21.3	0.0%	15.8	0.0%
FIT^3 Ramsey's RESET F	12.9	0.0%	11.4	0.0%
FIT^4 Ramsey's RESET F	13.4	0.0%	9.8	0.0%
Out-of-Sample RMSE	709		709	
Out-of-Sample MAE	491		491	
Out-of-Sample MAPE	0.43%		0.43%	

Commercial Customer Count - Moderate Growth

Estimation Start/End:	1/1991 - 3/2014
Unit Modeled/Forecast:	Monthly Customer Count

	OLS Model			ARMA Test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(114,944)	0.00%		0.00%
Trend	27	0.00%	1.46	0.00%
Binary_Jun_2013_2030	(165)	0.01%	1.24	0.50%
13co_Edu_Health_LN_t_lead_9	3,205	0.00%	2.09	0.00%
13co_Population_LN_lag_12	15,278	0.00%	1.34	0.00%



	OLS Model	
	Count	Y/Y Growth
2007	20,630	
2008	20,969	1.6%
2009	21,287	1.5%
2010	21,491	1.0%
2011	21,603	0.5%
2012	21,614	0.1%
2013	21,915	1.4%
2014	21,921	**0.0%**
2015	22,376	**2.1%**
2016	22,644	**1.2%**
2017	22,928	**1.3%**
2018	23,205	**1.2%**
2019	23,469	**1.1%**
2020	23,749	**1.2%**
		5 yr CAGR
2025	25,107	***1.1%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	99.8%		99.8%	
AIC	9.34		9.23	
SIC	9.41		9.32	
MAPE	0.4%		0.4%	
Model F Test	30443.7	0.0%	22911.0	0.0%
Estimates Residual S.D.	106		100	
SSres	3,064,263		2,695,405	
Degrees of Freedom	274		272	
Breusch-Pegan F	1.0	38.9%	2.8	2.6%
Breusch-Pegan ChiSq	4.2	38.6%	11.0	2.6%
White's F	1.7	18.5%	4.6	1.1%
Breusch-Godfrey AIC F	5.5	0.0%	3.9	0.0%
Breusch-Godfrey AIC ChiSq	82.4	0.0%	46.8	0.0%
Breusch-Godfrey SIC F	20.1	0.0%	0.2	64.4%
Breusch-Godfrey SIC ChiSq	36.0	0.0%	0.4	52.4%
Durban-Watson	1.4		2.0	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	0.2	63.8%	-15.6	#NUM!
FIT^3 Ramsey's RESET F	5.1	0.7%	1.5	22.7%
FIT^4 Ramsey's RESET F	3.6	1.3%	2.3	7.7%
Out-of-Sample RMSE	109		109	
Out-of-Sample MAE	79		79	
Out-of-Sample MAPE	0.42%		0.42%	

Model Discussion

The AFR 2014 forecast of commercial customer count growth moderated due to persistently low growth in the recent historical timeframe. Key economic drivers of customer growth include Employment in the Education & Health sector (13 county) and Population (13 county). This differs from last year's model which utilized Area Households (13 county) as the sole economic driver of customer count growth. Nearly all of the top models for Commercial customer count contained Employment in the Education and Health sector, which affirms this model's selection.

Minnesota Power's econometric interpretation of the key drivers is as follows: For each 1% increase in Education & Health sector employment, the customer count should increase by about 32 (about 0.15%). As area Population increases by 1%, the customer count should increase by about 152 (about 0.69%). These impacts are in addition to a general upward trend over time.

A binary variable starting in June 2013 effectively shifts the first forecast year (2014) to align with the last historical year (2013). Without this corrective binary variable, a small but growing divergence between actual and predicted customer growth (beginning in June, 2013) suggests the economic indicators alone would overstate customer count, and the 2014 forecast value confirms this. Without these binary variables, the model would project an increase of 300 customers from 2013 to 2014 (a 1.4% increase). The corrective binary variables shift the forecast down to avoid improbable increases in customer counts, but do not impact the forecast trajectory; this is determined by the economic variables.

This year's model reduced out-sample forecast error (MAPE) to 0.43% from 1% last year's model and improved other key metrics such as SIC and R-Squared, and halved in-sample forecast error (traditional MAPE). The OLS model passed all tests for Heteroskedasticity. ARMA testing of the OLS model for autocorrelation confirmed the significance (P-values) of the economic variables' coefficients and solve Ramsey's RESET F tests suggest exponential transformations were unlikely to improve the model's statistical measures. The very low VIF of each variable proves there is no significant multicollinearity.

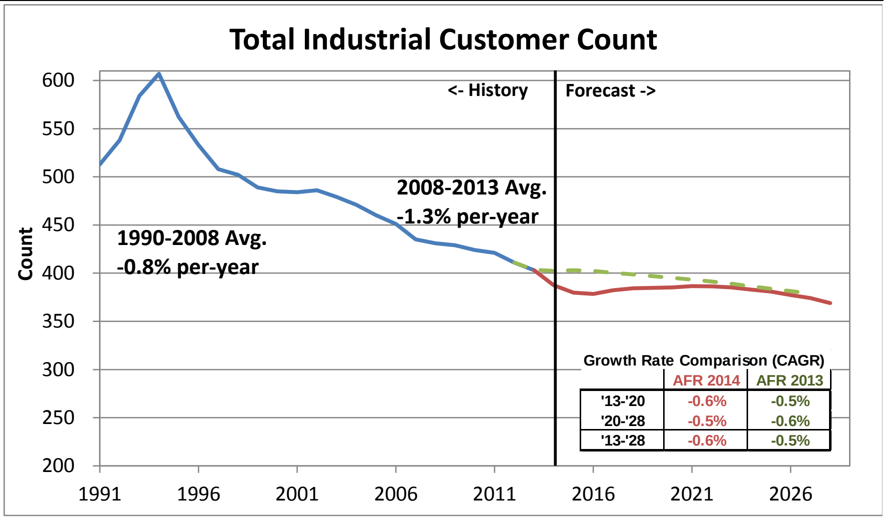
Industrial Customer Count - Moderate Growth

Estimation Start/End:	1/1991 - 3/2014
Unit Modeled/Forecast:	Monthly Customer Count

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(3.05)	0.00%		0.11%
Trend	(0.001)	0.00%	1.59	0.00%
Binary_05_2012-2030	0.020	0.08%	1.37	75.66%
MSA_Population_t_lag_12	0.032	0.00%	1.08	0.00%
MSA_RetailTrd_t_lead_12	0.035	0.00%	1.22	0.00%

	OLS Model	
	Count	Y/Y Growth
2007	435	
2008	431	-0.9%
2009	429	-0.5%
2010	424	-1.2%
2011	421	-0.7%
2012	411	-2.4%
2013	403	-1.9%
2014	387	**-3.9%**
2015	380	**-2.0%**
2016	378	**-0.3%**
2017	382	**1.0%**
2018	384	**0.5%**
2019	385	**0.1%**
2020	385	**0.1%**
2025	381	*5 yr CAGR -* ***0.2%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	95.8%		99.2%	
AIC	-7.55		-9.23	
SIC	-7.48		-9.07	
MAPE	0.3%		0.1%	
Model F Test	1598.2	0.0%	3310.9	0.0%
Estimates Residual S.D.	0		0	
SSres	0		0	
Degrees of Freedom	274		267	
Breusch-Pegan F	13.0	0.0%	0.7	59.3%
Breusch-Pegan ChiSq	44.4	0.0%	2.8	58.9%
White's F	32.5	0.0%	3.6	2.9%
Breusch-Godfrey AIC F	103.7	0.0%	2.9	0.0%
Breusch-Godfrey AIC ChiSq	226.6	0.0%	57.6	0.0%
Breusch-Godfrey SIC F	654.5	0.0%	0.1	80.7%
Breusch-Godfrey SIC ChiSq	229.7	0.0%	5.7	1.7%
Durban-Watson	0.2		2.0	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	307.3	0.0%	16.4	0.0%
FIT^3 Ramsey's RESET F	183.9	0.0%	18.2	0.0%
FIT^4 Ramsey's RESET F	122.2	0.0%	12.6	0.0%
Out-of-Sample RMSE	0		0	
Out-of-Sample MAE	0		0	
Out-of-Sample MAPE	0.38%		0.38%	



Model Discussion

The AFR 2014 forecast of Industrial customer count growth is similar to last year's. Key economic drivers of customer growth include Population (Duluth MSA) and Employment in Retail Trade (Duluth MSA). This differs from last year's model which utilized Employment in Manufacturing (13 county) as the sole economic driver of customer count growth.

The selection of Employment in Retail Trade as an indicator of Industrial customer count may seem incongruent, but this variable was selected repeatedly for inclusion by Minnesota Power's model generation tool and many of the top ranked models included this as an indicator. This variable most likely serves as a proxy for general economic conditions and supplements the Population variable, which predicts the underlying growth of the series.

Minnesota Power's econometric interpretation of the key drivers is as follows: As the Duluth MSA's Population increases by 1,000, Industrial customer count should increase by 3.3% (about 13 customers). As Duluth MSA's employment in Retail Trade increases by 1,000 the customer count should increase by 3.5% (about 14 customers). These impacts are in addition to a general downward trend over time.

A binary variable starting in May of 2012 effectively shifts the first forecast year (2014) to align more closely with the last historical year (2013). This corrective shift reduced the 2013-to-2014 decrease in customer count is limited to 16 (4%) instead of 18 (4.5%). The difference in the first forecast year is not substantial but by 2020, the decrease is limited to 20 (5%) instead of 28 (7%). The corrective binary variable shifts the forecast up slightly to avoid improbable decreases in customer counts, but does not impact the forecast trajectory; this is determined by the economic variables.

This year's model utilizes a logged form of the dependent variable so comparison of statistical quality should be done using forecast errors instead of SIC or R-squared. The AFR 2014 model reduced out-sample forecast error (MAPE) to 0.38% from 1.6% in last year's model, and reduced in-sample forecast error (traditional MAPE) to 0.3% from 0.8% in last year's model.

ARMA testing of the OLS model resolved heteroscedasticity and lower-order autocorrelation to confirm the significance (P-values) of the economic variables' coefficients. Low VIF for each variable proves there is no significant multicollinearity.

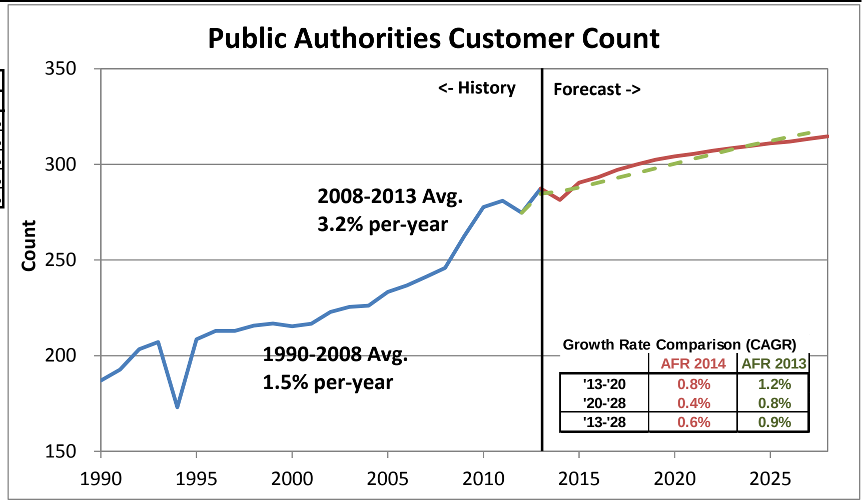
Public Authorities Customer Count - Moderate Growth

Estimation Start/End:	1/1991 - 3/2014
Unit Modeled/Forecast:	Monthly Customer Count

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	5.00	0.00%		0.00%
Trend	0.001	0.00%	2.09	0.00%
Binary_Aug_2009-2030	0.103	0.00%	2.05	0.00%
MSA_Edu_Health_lag_12	0.011	0.00%	1.03	0.00%
MSA_Empl-to-Pop_LN_diff_lead_12	1.81	0.01%	1.09	9.38%

	OLS Model	
	Count	Y/Y Growth
2007	241	
2008	246	1.9%
2009	262	6.7%
2010	278	5.8%
2011	281	1.2%
2012	275	-2.3%
2013	287	4.6%
2014	281	**-2.1%**
2015	290	**3.2%**
2016	293	**1.0%**
2017	297	**1.3%**
2018	300	**0.9%**
2019	302	**0.8%**
2020	304	**0.6%**
		5 yr CAGR
2025	311	***0.4%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	98.1%		99.1%	
AIC	-8.22		-8.90	
SIC	-8.15		-8.76	
MAPE	0.2%		0.2%	
Model F Test	3555.3	0.0%	2910.1	0.0%
Estimates Residual S.D.	0		0	
SSres	0		0	
Degrees of Freedom	274		268	
Breusch-Pegan F	5.3	0.0%	2.3	6.0%
Breusch-Pegan ChiSq	20.2	0.0%	9.0	6.1%
White's F	6.9	0.1%	1.6	19.4%
Breusch-Godfrey AIC F	22.8	0.0%	4.7	0.0%
Breusch-Godfrey AIC ChiSq	135.9	0.0%	45.3	0.0%
Breusch-Godfrey SIC F	78.1	0.0%	5.8	0.0%
Breusch-Godfrey SIC ChiSq	149.3	0.0%	37.1	0.0%
Durban-Watson	0.6		1.9	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	2.2	13.6%	5.5	2.0%
FIT^3 Ramsey's RESET F	3.7	2.5%	3.3	3.9%
FIT^4 Ramsey's RESET F	62.1	0.0%	3.6	1.4%
Out-of-Sample RMSE	0		0	
Out-of-Sample MAE	0		0	
Out-of-Sample MAPE	0.29%		0.29%	



Model Discussion

The AFR 2014 forecast of Public Authorities customer count growth is similar to last year's. Key economic drivers of customer growth include Employment in the Education & Health sector (Duluth MSA) and the Employment-to-Population ratio (Duluth MSA). The employment-to-population ratio metric is similar to an employment rate, but makes no adjustments for labor force participation. These drivers differ from last year's model which utilized Area Households (13 county) as the sole economic driver of customer count growth.

Minnesota Power's econometric interpretation of the key drivers is as follows: For every 1,000 jobs added in the Education & Health sector at the Duluth MSA level, the customer count should increase by about 1.2% (about 3 customers). A 1% increase in the Duluth MSA's month-to-month percent change in the Employment-to-Population ratio should increase customer count by about 1.8% (about 5 customers). These impacts are in addition to a general upward trend over time.

A binary variable starting in August of 2009 effectively shifts the first forecast year (2014) to align with the last historical year (2013). Without this corrective binary variable the economic indicators alone would understate customer count, The corrective binary variables shift the forecast up slightly to avoid improbable decreases in customer counts, but do not impact the forecast trajectory; this is determined by the economic variables.

This year's model reduced out-sample forecast error to 0.3% from 2.3% in last year's model, reduced in-sample forecast error to 0.2% from 2% in last year's model, and improved other key metrics such as SIC and R-Squared.

ARMA testing of the OLS model was able to resolve heteroscedasticity. However the model was only able to resolve first, second, and third-order autocorrelation. It's possible that the P-values of the coefficients are over-estimated due to some higher-level autocorrelation. Other top model shared this characteristic. Low VIF for each variable proves there is no significant multicollinearity.

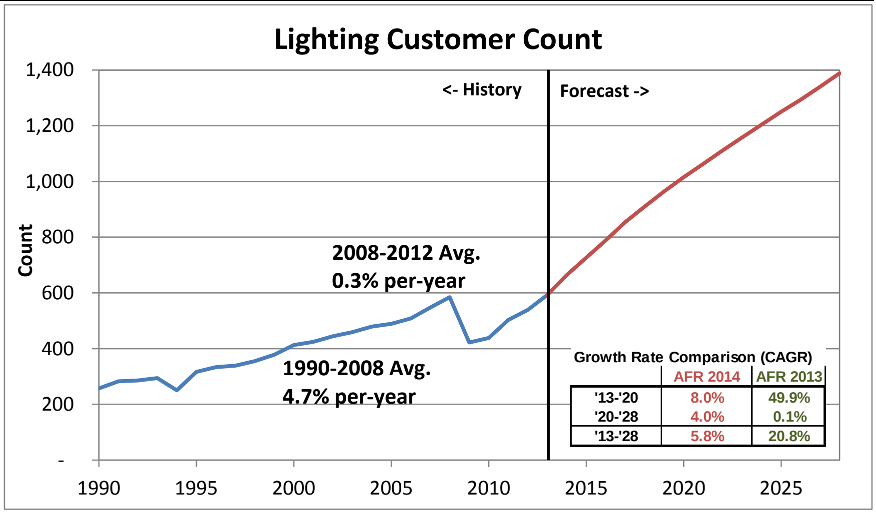
Street Lighting Customer Count - Moderate Growth

Estimation Start/End:	2/1991 - 3/2014
Unit Modeled/Forecast:	Monthly Customer Count

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(212.28)	0.00%		5.26%
Trend	1.51	0.00%	2.06	0.00%
Binary_Jul_2009_2030	(989.05)	0.00%	278.94	0.00%
Trend_Jul_2009_2030	3.44	0.00%	279.60	0.00%
MP_13_Edu_Health_lag_12	0.012	0.00%	1.42	0.00%
MSA_Population_diff_lag_12	81.04	0.00%	1.17	0.01%

	OLS Model	
	Count	Y/Y Growth
2007	548	
2008	585	6.8%
2009	422	-27.8%
2010	438	3.8%
2011	503	14.8%
2012	539	7.2%
2013	592	9.8%
2014	664	**12.2%**
2015	726	**9.4%**
2016	789	**8.6%**
2017	854	**8.3%**
2018	910	**6.5%**
2019	964	**6.0%**
2020	1,015	**5.2%**
		5 yr CAGR
2025	1,250	***4.3%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	99.1%		99.8%	
AIC	4.65		3.37	
SIC	4.72		3.56	
MAPE	1.9%		0.9%	
Model F Test	6037.9	0.0%	8589.4	0.0%
Estimates Residual S.D.	10		5	
SSres	27,751		7,330	
Degrees of Freedom	272		264	
Breusch-Pegan F	4.1	0.1%	1.8	8.7%
Breusch-Pegan ChiSq	19.6	0.2%	12.4	8.8%
White's F	8.1	0.0%	4.9	0.8%
Breusch-Godfrey AIC F	650.0	0.0%	0.0	91.6%
Breusch-Godfrey AIC ChiSq	195.7	0.0%	15.1	0.0%
Breusch-Godfrey SIC F	650.0	0.0%	0.0	91.6%
Breusch-Godfrey SIC ChiSq	195.7	0.0%	15.1	0.0%
Durban-Watson	0.3		1.9	
Durban-H	#NA	N/A	0.6	N/A
FIT^2 Ramsey's RESET F	83.2	0.0%	-44.6	#NUM!
FIT^3 Ramsey's RESET F	41.6	0.0%	13.4	0.0%
FIT^4 Ramsey's RESET F	49.6	0.0%	9.0	0.0%
Out-of-Sample RMSE	13		16	
Out-of-Sample MAE	10		10	
Out-of-Sample MAPE	2.46%		2.40%	



Model Discussion

The AFR 2014 forecast of Street Lighting customer count growth is notably different than last year's forecast. As noted in the section on Data Revisions Since Previous AFR, Minnesota Power used the an older billing practices to revise lighting customer counts in the 2009-2013 timeframe. This creates a constantly-defined series that can be accurately forecasted.

The key drivers of this year's model differ from last year's model which utilized no economic variables. Last year's model was driven by lagged-dependent variables and a binary to indicate a step change. More than half of all top models for Street Lighting customer count contained Employment in the Education and Health sector, which affirms this model's selection.

Key economic drivers of customer growth include Employment in the Education & Health sector (13 county) and Population (Duluth MSA). The Population variable is differenced to show month-to-month change in population rather than the level. As noted in the section on "Data Revisions Since Previous AFR," starting in 2009, a change in billing practices caused the street lighting customer count to increase from around 600 to nearly 6,000 in 2010. For AFR 2014, the historical count in the 2009-2013 timeframe was adjusted for consistency with pre-2009 account practices.

Minnesota Power's econometric interpretation of the key drivers is as follows: For every 1,000 jobs added in the Education & Health sector in the 13 county planning area, the customer count should increase by about 12. As the month-to-month change in Duluth MSA population increases by 1,000, street lighting customer count should increases by about 81. These impacts are in addition to a general upward trend over time.

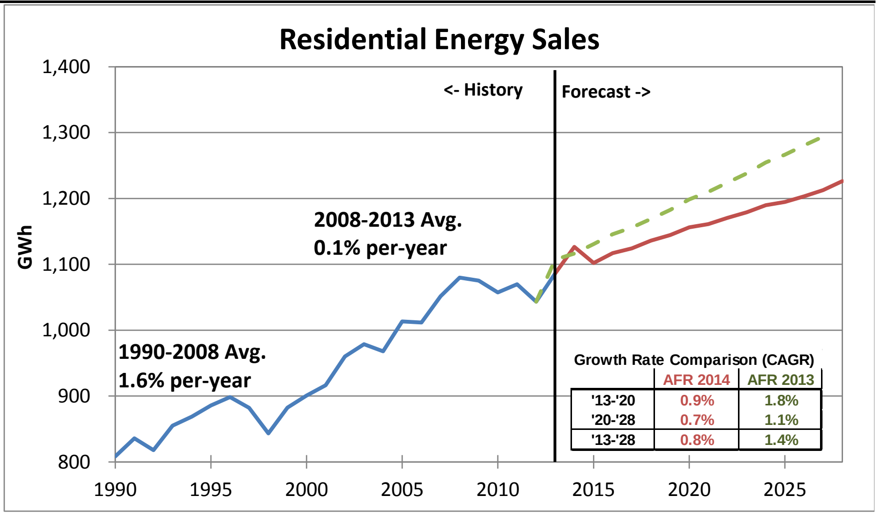
A binary variable starting in July of 2009 accounts for a step change in the historical. Although, Minnesota Power did its best to replicate the previous billing practices and construct a consistent histrionical customer count series to model, there is an obvious break in the series. This binary variable accounts for this break.

This year's model reduced out-sample forecast error (MAPE) to 2.46% (from 62% in last year's model), halved the SIC, and reduced in-sample MAPE forecast error to 1.9% from 2.2% in last year's model. ARMA testing of the OLS model was able to resolve heteroscedasticity and autocorrelation to confirm the P-values of each variables

Residential Energy Use - Moderate Growth

Estimation Start/End:	8/1990 - 3/2014
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (KWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	18.394	0.00%		0.00%
Binary_Aug	1.689	0.13%	2.51	0.11%
Trend_Jan	0.028	0.00%	3.72	0.00%
Trend_Mar	0.010	0.84%	3.92	0.99%
Trend_Jul	0.009	5.00%	5.00	8.56%
Trend_Nov	0.012	0.06%	3.21	0.22%
Trend_Dec	0.030	0.00%	4.05	0.00%
HDD_ElecHeat_Jan	1.356	0.00%	4.03	0.00%
HDD_Feb	0.202	0.00%	1.51	0.00%
HDD_ElecHeat_Mar	1.124	0.00%	4.30	0.00%
HDD_Apr	0.151	0.00%	1.49	0.00%
HDD_ElecHeat_May	0.730	0.55%	1.53	0.52%
CDD_Jul	0.493	1.12%	4.87	0.62%
CDD_CAC_Aug	1.454	1.70%	2.01	5.96%
HDD_ElecHeat_Sep	0.870	1.37%	1.49	1.02%
HDD_Oct	0.077	0.01%	1.50	0.01%
HDD_Nov	0.105	0.00%	3.63	0.00%
HDD_Dec	0.133	0.00%	4.60	0.00%
13co_WageDisb_diff_lag_5	0.005	0.08%	1.10	0.37%
13co_Gov_LN_diff_lag_6	22.431	1.53%	1.09	9.98%



	OLS Model	
	MWh	Y/Y Growth
2007	1,051,453	
2008	1,079,837	2.7%
2009	1,075,116	-0.4%
2010	1,057,476	-1.6%
2011	1,069,856	1.2%
2012	1,043,281	-2.5%
2013	1,086,481	4.1%
2014	1,126,533	**3.7%**
2015	1,101,872	**-2.2%**
2016	1,117,148	**1.4%**
2017	1,124,315	**0.6%**
2018	1,135,933	**1.0%**
2019	1,144,295	**0.7%**
2020	1,156,269	**1.0%**
		5 yr CAGR
2025	1,194,569	***0.7%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	89.0%		89.4%	
AIC	0.93		0.90	
SIC	1.18		1.17	
MAPE	5.1%		5.0%	
Model F Test	121.9	0.0%	120.0	0.0%
Estimates Residual S.D.	2		2	
SSres	623		602	
Degrees of Freedom	264		263	
Breusch-Pegan F	2.6	0.0%	2.5	0.1%
Breusch-Pegan ChiSq	44.7	0.1%	43.8	0.1%
White's F	9.8	0.0%	10.2	0.0%
Breusch-Godfrey AIC F	3.7	0.0%	3.0	0.1%
Breusch-Godfrey AIC ChiSq	43.3	0.0%	33.9	0.0%
Breusch-Godfrey SIC F	0.1	72.3%	1.5	21.5%
Breusch-Godfrey SIC ChiSq	0.2	63.6%	2.1	14.3%
Durban-Watson	2.0		2.1	N/A
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	1.1	28.9%	-7.9	#NUM!
FIT^3 Ramsey's RESET F	3.8	2.5%	1.9	14.5%
FIT^4 Ramsey's RESET F	2.6	5.6%	1.9	12.4%
Out-of-Sample RMSE	2		2	
Out-of-Sample MAE	1		1	
Out-of-Sample MAPE	5.61%		5.61%	

Model Discussion

The AFR 2014 forecast of residential use-per customer is similar to last year's. The graph shown above combines the output of the use-per-customer per day model with the outputs of the customer count model to show total energy sales to Residential customers. The decrease in the total energy use forecast for the residential class is primarily due to the change in the customer count projection and not a substantive change in projected use-per-customer.

This year's model found Wage Distribution in the 13 county area and Employment in the Public sector for the 13 county area to be significant indicators of per-customer use. This differs from last year's model which used only weather, appliance saturation, and seasonal trend variables to predict residential customer use.

Minnesota Power's econometric interpretation of the key drivers is as follows: As the month-to-month change in wage distribution increases by $1 Million (about 0.1% of the current level), monthly use-per-customer should increase by about 0.156 KWh (0.005 KWh x 31 days). A 1% increase in Public Sector employment will increase monthly use-per-customer by about 7 KWh (0.223 x 31 days).

When modeling residential use-per-customer, monthly/seasonal binaries and trend variables occasionally appropriated the role of weather variables due to high collinearity and the model identifying the binary as the more indicative variable. In this case, the binary variable is dropped in favor of maintaining weather a predictor because it allows for accurate after-the-fact weather normalization later by the company.

Seasonal trend variables (denoted by "Trend_month") are used to identify months where usage has shown significant trending over time. These trends suggest that monthly usage patterns are evolving independent of weather, appliance saturation, and economic conditions. Summer and winter month trending is positive and significant. Shoulder month trends were found to be either insignificant or interacted with weather to produce colliniartiy issues, and therefore excluded. These findings are consistent with last year's results.

This year's model is highly comparable to last year's in terms of statistical quality. SIC, R-Squared, in-sample forecast error (traditional MAPE), and out-sample (RMSE) are all fairly close. The OLS model passes several of the tests for Autocorrelation, but heteroscedasticity is present and ARMA testing of the OLS model was unable to resolve this. However, given that no alternative models with quality statistics and plausible growth rates could solve for heteroscedasticity, Minnesota Power considers this model the optimal choice despite the potential for bias in the P-values.

Low VIF of each variable proves there is no significant multicollinearity and the Ramsey's RESET F tests suggest that the model is properly specified and transformations of variables would not yield additional predictive power.

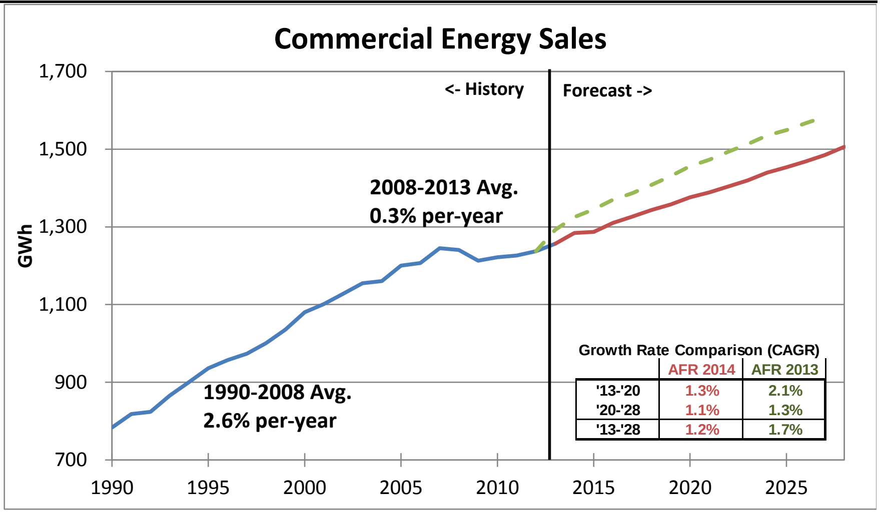
Commercial Energy Use - Moderate Growth

Estimation Start/End:	1/1991 - 3/2014
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (KWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(145.26)	2.59%		0.00%
Trend	0.03	0.02%	1.05	0.00%
Binary_Nov	(46.14)	0.21%	49.53	0.27%
HDD_Jan	0.30	0.00%	1.16	3.17%
HDD_Feb	0.50	0.00%	1.16	0.00%
HDD_Mar	0.43	0.00%	1.16	0.92%
CDD_Jun	5.49	0.06%	1.12	1.27%
CDD_Jul	3.58	0.00%	1.13	0.00%
CDD_Aug	7.97	0.00%	1.13	0.00%
HDD_Sep	1.62	0.00%	1.14	0.32%
HDD_Nov	1.45	0.06%	49.37	0.02%
HDD_Dec	0.54	0.00%	1.16	0.00%
13co_Finance_t_lag_12	0.0035	0.24%	1.50	0.00%
13co_MFG_LN_t_lag_5	25.74	0.03%	1.49	0.00%

	OLS Model	
	MWh	Y/Y Growth
2007	1,244,930	
2008	1,240,324	-0.4%
2009	1,212,778	-2.2%
2010	1,221,754	0.7%
2011	1,226,174	0.4%
2012	1,237,386	0.9%
2013	1,256,540	1.5%
2014	1,284,024	**2.2%**
2015	1,287,245	**0.3%**
2016	1,310,008	**1.8%**
2017	1,326,212	**1.2%**
2018	1,343,242	**1.3%**
2019	1,357,620	**1.1%**
2020	1,375,938	**1.3%**
		5 yr CAGR
2025	1,453,153	***1.1%***

	OLS Model		ARMA Test	
Model Statistics	**Magnitude**	**P-Value**	**Magnitude**	**P-Value**
Adjusted R^2	55.5%		70.5%	
AIC	4.59		4.21	
SIC	4.77		4.52	
MAPE	4.8%		3.8%	
Model F Test	27.7	0.0%	29.5	0.0%
Estimates Residual S.D.	10		8	
SSres	24,806		15,499	
Degrees of Freedom	265		251	
Breusch-Pegan F	2.3	0.8%	1.5	10.4%
Breusch-Pegan ChiSq	27.9	0.9%	22.0	10.8%
White's F	0.3	73.1%	0.2	85.9%
Breusch-Godfrey AIC F	9.1	0.0%	0.1	76.2%
Breusch-Godfrey AIC ChiSq	84.0	0.0%	4.8	2.8%
Breusch-Godfrey SIC F	32.9	0.0%	0.1	76.2%
Breusch-Godfrey SIC ChiSq	56.2	0.0%	4.8	2.8%
Durban-Watson	2.7		2.0	N/A
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	0.7	41.3%	5.1	2.5%
FIT^3 Ramsey's RESET F	2.2	11.3%	2.6	7.5%
FIT^4 Ramsey's RESET F	2.4	6.6%	2.2	9.2%
Out-of-Sample RMSE	10.0		10.2	
Out-of-Sample MAE	7.9		7.9	
Out-of-Sample MAPE	5.06%		5.10%	



Model Discussion

The AFR 2014 forecast of commercial use-per customer is a bit lower than last year's outlook. The graph shown above combines the output of the use-per-customer per day model with the outputs of the customer count model. The decrease in the total energy use forecast for the commercial class is due to a change in the customer count forecast and in the use-per-customer outlook. Employment in the Finance sector in the 13 county area and Employment in the Manufacturing sector for the 13 county area were found to be significant indicators of per-customer use.

Minnesota Power's econometric interpretation of the key drivers is as follows: For every 100 jobs added in the 13 county area Financial sector, monthly commercial use-per-customer should increase by about 11 KWh (0.0035 x 31 x 100). A 1% increase in the 13 county manufacturing sector employment should increase monthly commercial use-per-customer by about 8 KWh (0.26 x 31).

Weather's impact in shoulder months such as April or October was found to be insignificant and variables for these months were excluded from the model due to low P-value. This implies that, for the commercial class, there is a baseline of usage in these months that's largely unaffected by variations in weather. It's likely that weather does influence use in these months, but at an aggregated monthly level these impacts are indiscernible. Last year's model was very similar in its weather variable selection. These findings are consistent with last year's where shoulder month weather was also found to be insignificant

This year, commercial use-per-customer was modeled as KWh per customer whereas last year was modeled on a MWh per customer basis. This change has no material impact on the forecast. The change was made for consistency with residential energy sales which is also modeled as KWh per customer per day.

The AFR 2014 model is highly comparable to last year's in terms of statistical quality. R-Squared, in-sample forecast error (traditional MAPE), and out-sample (RMSE) are all fairly close (after accounting for the difference in the dependent variable). ARMA testing of the OLS model resolves heteroscedasticity and autocorrelation to confirm the significance of the coefficients.

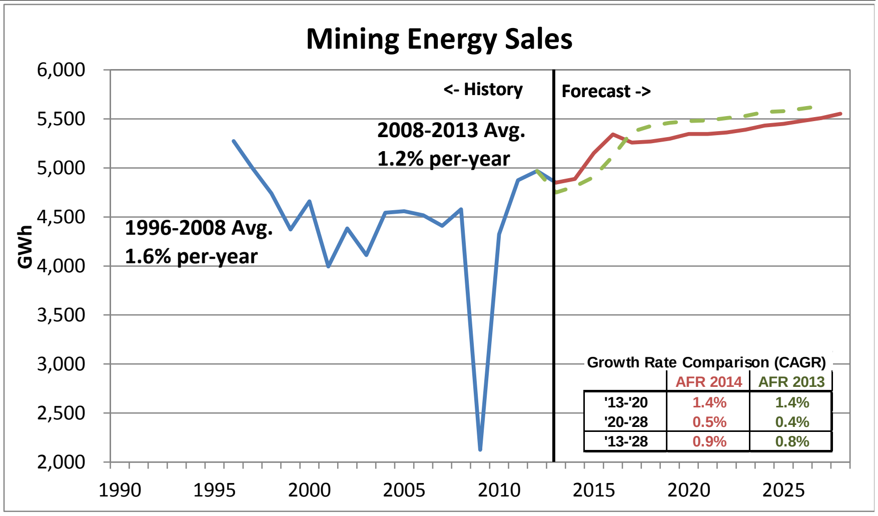
Low VIF of each variable proves there is no significant multicollinearity and the Ramsey's RESET F tests suggest that the OLS model is properly specified; transformations would not improve the predictive ability of this model.

Mining and Metals Energy Use - Moderate Growth

Estimation Start/End:	1/1996 - 3/2014
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(21,079.13)	0.00%		0.00%
Trend	(4.17)	0.00%	1.05	0.00%
IPI_Iron_LN	7,278	0.00%	49.53	0.27%

	OLS Model	
	MWh	Y/Y Growth
2007	4,408,337	
2008	4,579,234	3.9%
2009	2,124,675	-53.6%
2010	4,324,450	103.5%
2011	4,874,331	12.7%
2012	4,968,517	1.9%
2013	4,851,094	-2.4%
2014	4,888,265	**0.8%**
2015	5,152,115	**5.4%**
2016	5,343,277	**3.7%**
2017	5,259,033	**-1.6%**
2018	5,269,835	**0.2%**
2019	5,298,345	**0.5%**
2020	5,346,458	**0.9%**
		5 yr CAGR
2025	5,450,764	***0.4%***



Model Discussion

The outlook for Mining and Metals energy sales is a bit higher than last year's in the short-term and slightly lower in the long-term. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions. The underlying econometric forecasts are highly similar; the AFR 2014 forecast is just 0.4% higher (on average over the forecast timeframe) than AFR 2013's forecast. The change in assumptions for large customer load additions is the primary reason for the difference between this and last year's energy sales forecast.

The dependent variable being modeled differs from last year. AFR 2013's model utilized raw historical sales to Mining and Metals customers whereas the AFR 2014 is modeled on an adjusted Mining and Metals sales history which backs out recent customer load additions. This methodology is explained in the "Methodological Adjustments for the 2014 Forecast" section and specific adjustments made to the historical series are detailed in the "Data Revisions Since Previous AFR" section.

The AFR 2014 model differs from last year's in its limited use of explanatory variables. This year's model uses only the Industrial Production Index (IPI) for Iron and a trend variable, whereas last year's model incorporated some monthly binaries and a lagged dependent variable. Monthly binaries were found to be insignificant in this year's model; likely due to the exclusion of the lagged dependent variable and the use of an already seasonally-adjusted IPI series. The IPI Iron variable in the AFR 2014 model is in logged form so its econometric interpretation is as follows: for each 1% increase in the IPI for Iron, Minnesota Power's Mining and Metals customers should increase monthly use by about 2,256 (73 x 31).

The AFR 2014 model is highly comparable to last year's in terms of statistical quality. R-Squared, in-sample forecast error (traditional MAPE), and out-sample (RMSE) are all fairly close. ARMA testing of the OLS model resolves autocorrelation but could not conclusively eliminate heteroscedasticity. As a result, there is the potential that the P-values of the coefficients are bias. However, autocorrelation or heteroscedasticity cannot bias the coefficients, so the only question is whether the IPI for Iron is a significant predator of Mining and Metals customer energy use. All of this year's top mining and metals models utilized IPI for Iron and it has been in use by Minnesota Power to forecast customer use since 2009, so it's clear this variable is significant.

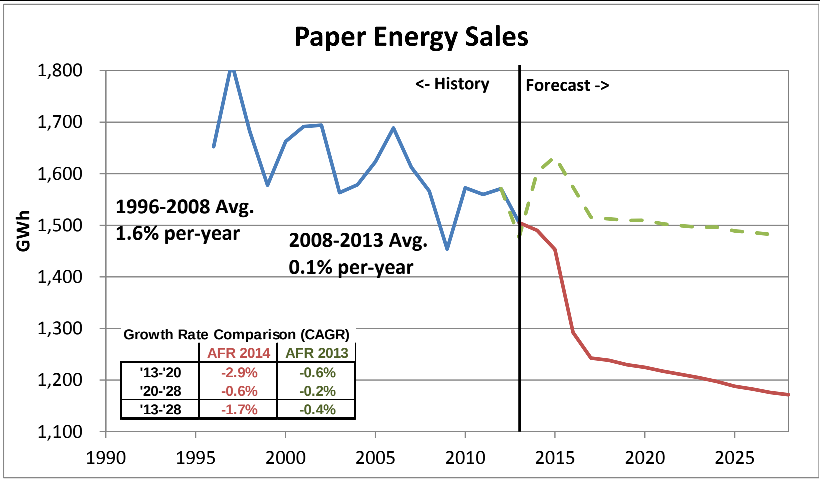
ARMA testing also suggested that the true P-value of the trend variable is 96%, which would be considered insignificant. However, the only reason this occurs in the ARMA model is because AR and MA terms have adopted the role of trend variable. Therefore, this variable is not dropped from the model due to a high ARMA tested P-value.

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	80.7%		90.4%	
AIC	13.54		12.84	
SIC	13.59		12.98	
MAPE	6.7%		4.2%	
Model F Test	457.9	0.0%	240.9	0.0%
Estimates Residual S.D.	866		600	
SSres	161,884,382		70,573,379	
Degrees of Freedom	216		196	
Breusch-Pegan F	35.0	0.0%	5.1	0.2%
Breusch-Pegan ChiSq	53.7	0.0%	14.5	0.2%
White's F	29.7	0.0%	7.7	0.1%
Breusch-Godfrey AIC F	58.5	0.0%	0.1	71.4%
Breusch-Godfrey AIC ChiSq	77.3	0.0%	0.8	36.9%
Breusch-Godfrey SIC F	58.5	0.0%	0.1	71.4%
Breusch-Godfrey SIC ChiSq	77.3	0.0%	0.8	36.9%
Durban-Watson	0.8		1.9	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	22.4	0.0%	-14.2	#NUM!
FIT^3 Ramsey's RESET F	18.0	0.0%	7.5	0.1%
FIT^4 Ramsey's RESET F	14.2	0.0%	5.4	0.1%
Out-of-Sample RMSE	976		735	
Out-of-Sample MAE	727		552	
Out-of-Sample MAPE	7.51%		5.44%	

Paper and Wood Products Energy Use - Moderate Growth

Estimation Start/End:	1/1996 - 3/2014
Unit Modeled/Forecast:	Natural Log of Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	5.75	0.00%		0.00%
Binary_Mar	0.05	0.08%	1.15	0.11%
Binary_Apr	0.04	0.77%	1.14	0.64%
Binary_Jun	0.07	0.00%	1.14	0.00%
Binary_Jul	0.04	0.30%	1.15	0.19%
Binary_Aug	0.09	0.00%	1.15	0.00%
Binary_Sep	0.09	0.00%	1.14	0.00%
Binary_Oct	0.09	0.00%	1.14	0.00%
Binary_Nov	0.04	1.33%	1.14	0.01%
IPI_Paper_LN	0.55	0.00%	1.29	0.00%
13co_ProductPerCap_LN_diff_lead_12	12.35	0.00%	1.27	0.05%
MSA_PerCapita_TPI_LN_diff_lead_3	3.95	0.04%	1.05	8.70%



	OLS Model	
	MWh	Y/Y Growth
2007	1,612,560	
2008	1,566,402	-2.9%
2009	1,453,928	-7.2%
2010	1,572,565	8.2%
2011	1,559,519	-0.8%
2012	1,570,852	0.7%
2013	1,505,113	-4.2%
2014	1,492,657	**-0.8%**
2015	1,450,643	**-2.8%**
2016	1,287,813	**-11.2%**
2017	1,243,115	**-3.5%**
2018	1,237,921	**-0.4%**
2019	1,229,691	**-0.7%**
2020	1,224,624	**-0.4%**
		5 yr CAGR -
2025	1,187,916	***0.6%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	43.2%		58.1%	
AIC	-5.79		-6.09	
SIC	-5.61		-5.89	
MAPE	0.5%		0.4%	
Model F Test	16.1	0.0%	26.1	0.0%
Estimates Residual S.D.	0		0	
SSres	1		0	
Degrees of Freedom	207		205	
Breusch-Pegan F	1.7	7.3%	1.1	33.2%
Breusch-Pegan ChiSq	18.2	7.6%	12.5	32.7%
White's F	1.1	33.6%	0.6	54.5%
Breusch-Godfrey AIC F	70.9	0.0%	0.5	46.5%
Breusch-Godfrey AIC ChiSq	56.0	0.0%	2.7	9.9%
Breusch-Godfrey SIC F	70.9	0.0%	0.5	46.5%
Breusch-Godfrey SIC ChiSq	56.0	0.0%	2.7	9.9%
Durban-Watson	1.0	BAD	2.1	N/A
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	0.0	93.4%	2.0	15.7%
FIT^3 Ramsey's RESET F	1.0	37.6%	1.1	32.6%
FIT^4 Ramsey's RESET F	0.6	58.7%	0.7	52.4%
Out-of-Sample RMSE	0		0	
Out-of-Sample MAE	0		0	
Out-of-Sample MAPE	0.57%		0.57%	

Model Discussion

The AFR 2014 outlook for Paper and Wood Products energy sales is lower than last year's. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions. The underlying econometric forecast reflects a weakening of the domestic paper industry as a whole; by 2025, the AFR 2014's econometric forecast is about 3% lower than last year's. Load addition/ loss assumptions have also been updated to reflect expected changes in customer operation plans. These updates reduce expected sales in the forecast timeframe.

The dependent variable being modeled differs from last year. AFR 2013's model utilized raw historical sales to Paper and Wood customers whereas the AFR 2014 is modeled on an adjusted history which backs out the historical energy sales of customers that were recently lost. This methodology is explained in the "Methodological Adjustments for the 2014 Forecast" section and specific adjustments made to the historical series are detailed in the "Data Revisions Since Previous AFR" section.

The AFR 2014 model for Paper and Wood differs from last year's in its inclusion of regional economic variables. In past forecast models for this sector, Minnesota Power utilized the Industrial Production Index for Paper as the sole economic driver of energy sales to this customer class. The comprehensive specification search process and internally developed software enabled Minnesota Power to identify regional economic indicators that added predictive value to the forecast model.

The AFR 2014 model uses the Industrial Production Index (IPI) for Paper, Product-per-Capita (Gross Regional Product divided by Population) for the 13 county area, and Per-capita Total Personal Income for the 13 county area. Minnesota Power's econometric interpretation of the key drivers is as follows: A 1% increase in the Paper IPI should increase monthly Paper and Wood customer use by about 0.5% (about 600 MWh). A 1% increase in the rate of change in Regional Product-per-Capita and Total Personal Income per-Capita would cause a 13% and 4% (respectively) increase in monthly Paper customer usage.

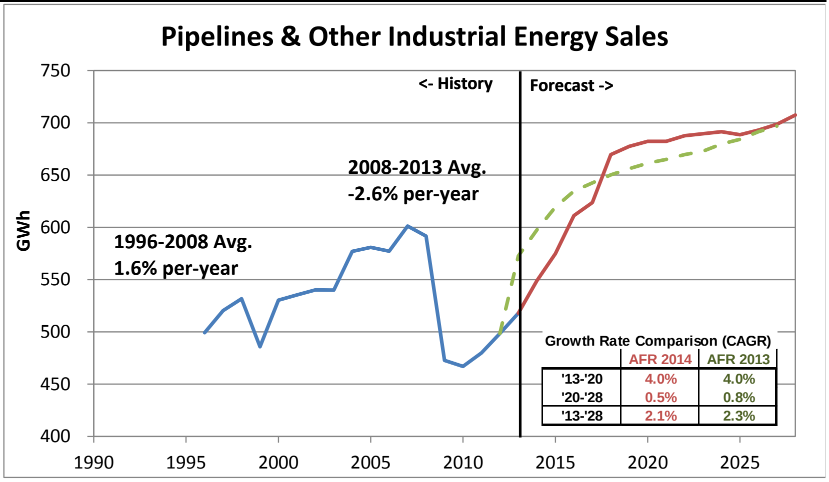
This year's model utilizes a logged form of the dependent variable so comparison of statistical quality should be done using forecast errors instead of SIC or R-squared. Review of the in-sample and out-sample MAPE show this model is a vast improvement over last year in terms of forecast accuracy: in-sample MAPE decreased to 0.5% from 3.7% in last year's model, and the out-sample MAPE decreased to 0.57% from 4.3% in last year's model.

Pipelines and Other Industrial Energy Use - Moderate Growth

Estimation Start/End:	1/1996 - 3/2014
Unit Modeled/Forecast:	Natural Log of Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	5.01	0.00%		0.00%
Trend	0.0012	0.00%	2.84	6.67%
13co_Trd_Trns_Util_lag_5	0.000045	0.00%	2.84	1.15%

	OLS Model	
	MWh	Y/Y Growth
2007	601,155	
2008	591,697	-1.6%
2009	472,749	-20.1%
2010	467,065	-1.2%
2011	479,798	2.7%
2012	498,474	3.9%
2013	517,786	3.9%
2014	548,827	**6.0%**
2015	574,883	**4.7%**
2016	611,277	**6.3%**
2017	623,627	**2.0%**
2018	669,531	**7.4%**
2019	677,462	**1.2%**
2020	682,225	**0.7%**
		5 yr CAGR
2025	688,571	***0.2%***



Model Discussion

The outlook for Pipelines and Other Industrial energy sales is very comparable to last year's. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions. The underlying econometric forecast is fairly similar to last year's forecast, and differences are due to utilizing an adjusted historical sales series in modeling this year.

The dependent variable being modeled differs from the variable modeled in last year's AFR. AFR 2013's model utilized raw historical sales to Pipelines and Other Industrial Customers whereas the AFR 2014 is modeled on an adjusted history which backs out the historical energy sales of recent customer load additions and any customers that were lost in the early historical timeframe. This methodology is explained in the "Methodological Adjustments for the 2014 Forecast" section and specific adjustments made to the historical series are detailed in the "Data Revisions Since Previous AFR" section.

Load addition/ loss assumptions have been updated to reflect expected changes in customer operation plans. These updated assumptions lower the forecast in the 2014-2017 timeframe, but increase the forecast after 2017.

The AFR 2014 econometric model for Pipelines and Other Industrial is very similar to last year's model. Both utilized Employment in Trade, Transportation, and Utilities as the primary economic variable. Last year's model also utilized area population, but the 2014 AFR analysis indicated that this variable added little value to the model and was excluded. The forecast for employment in Trade, Transportation, and Utilities hasn't changed substantively since last year, and this explains the similarity in the econometric forecasts between this year and last.

Minnesota Power's econometric interpretation of the key drivers is as follows: For every 100 jobs added to the Trade, Transportation, and Utilities sector in the 13 county area, the energy sales to this customer class should increase by about 0.5%.

This year's model utilizes a logged form of the dependent variable so comparison of statistical quality should be done using forecast errors instead of SIC or R-squared. The in-sample and out-sample MAPE show this model is a vast improvement over last year in terms of forecast accuracy: in-sample MAPE decreased to 0.9% from 7.5% in last year's model, and the out-sample MAPE decreased to 1.1% from 14.1% in last year's model.

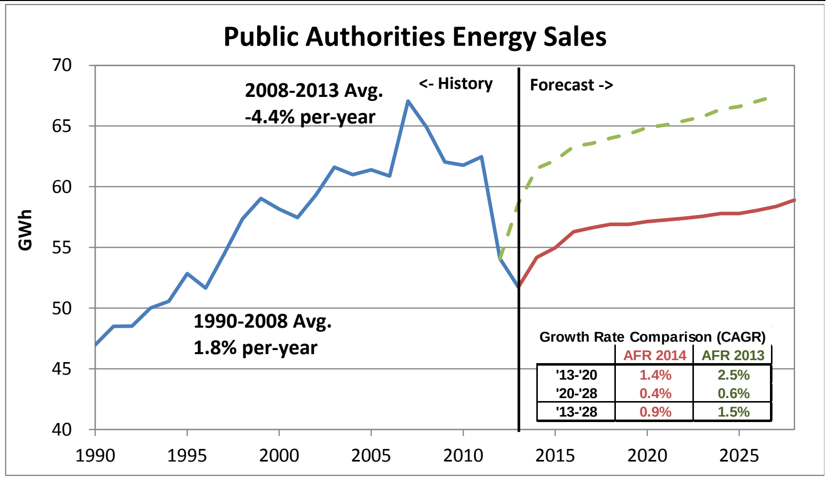
Tests of the OLS model show it has no significant heteroscedasticity, but suggest autocorrelation could potentially bias the P-values. ARMA testing was able to conclusively solve for autocorrelation and confirm the significance of the predictor variables.

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	31.1%		53.0%	
AIC	-4.92		-5.27	
SIC	-4.88		-5.16	
MAPE	0.9%		0.7%	
Model F Test	50.2	0.0%	39.2	0.0%
Estimates Residual S.D.	0		0	
SSres	2		1	
Degrees of Freedom	216		197	
Breusch-Pegan F	2.1	12.0%	0.5	63.4%
Breusch-Pegan ChiSq	4.3	11.9%	0.9	63.1%
White's F	1.0	36.5%	1.5	23.5%
Breusch-Godfrey AIC F	20.2	0.0%	0.0	92.9%
Breusch-Godfrey AIC ChiSq	60.8	0.0%	0.7	40.5%
Breusch-Godfrey SIC F	35.8	0.0%	0.0	92.9%
Breusch-Godfrey SIC ChiSq	55.3	0.0%	0.7	40.5%
Durban-Watson	1.1		2.0	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	18.5	0.0%	0.9	33.3%
FIT^3 Ramsey's RESET F	10.9	0.0%	1.1	34.9%
FIT^4 Ramsey's RESET F	7.3	0.0%	1.1	36.4%
Out-of-Sample RMSE	0		0	
Out-of-Sample MAE	0		0	
Out-of-Sample MAPE	1.08%		0.96%	

Public Authorities Energy Use - Moderate Growth

Estimation Start/End:	7/1990 - 3/2014
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(81.20)	4.91%		0.77%
Trend	0.19	0.00%	1.33	0.00%
Binary_04_2012-2030	(35.73)	0.00%	1.53	0.00%
Binary_Jan	41.93	0.55%	16.15	0.90%
Binary_Mar	47.34	0.18%	16.14	0.19%
Binary_May	38.02	1.18%	15.57	1.56%
Binary_Jun	45.67	0.26%	15.59	0.33%
Binary_Jul	58.03	0.01%	16.16	0.01%
Binary_Aug	54.32	0.04%	16.16	0.03%
Binary_Sep	50.85	0.08%	16.17	0.08%
Binary_Oct	45.68	0.25%	16.16	0.40%
HDD_Feb	0.97	0.14%	15.95	0.12%
HDD_Apr	1.58	0.71%	15.37	0.97%
HDD_Nov	1.23	0.36%	15.92	0.47%
HDD_Dec	1.12	0.03%	15.99	0.02%
MSA_Service_lead_5	2.04	0.00%	1.18	0.00%
13co_Con_Rsrcs_Mine_diff_lag_5	0.011	0.26%	1.06	2.84%



	OLS Model	
	MWh	Y/Y Growth
2007	67,056	
2008	64,912	-3.2%
2009	62,036	-4.4%
2010	61,768	-0.4%
2011	62,458	1.1%
2012	54,074	-13.4%
2013	51,736	-4.3%
2014	54,172	**4.7%**
2015	54,967	**1.5%**
2016	56,293	**2.4%**
2017	56,630	**0.6%**
2018	56,906	**0.5%**
2019	56,903	**0.0%**
2020	57,131	**0.4%**
		5 yr CAGR
2025	57,797	***0.2%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	45.8%		50.7%	
AIC	5.78		5.70	
SIC	6.00		5.97	
MAPE	8.6%		8.3%	
Model F Test	16.0	0.0%	15.2	0.0%
Estimates Residual S.D.	17		17	
SSres	81,807		71,010	
Degrees of Freedom	268		256	
Breusch-Pegan F	0.5	92.8%	0.7	82.1%
Breusch-Pegan ChiSq	8.8	92.1%	11.0	81.0%
White's F	2.5	8.8%	0.7	50.3%
Breusch-Godfrey AIC F	11.3	0.0%	0.1	81.2%
Breusch-Godfrey AIC ChiSq	32.4	0.0%	0.5	49.3%
Breusch-Godfrey SIC F	24.2	0.0%	0.1	81.2%
Breusch-Godfrey SIC ChiSq	23.7	0.0%	0.5	49.3%
Durban-Watson	2.6		2.0	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	6.6	1.1%	4.2	4.0%
FIT^3 Ramsey's RESET F	3.3	3.9%	3.1	4.8%
FIT^4 Ramsey's RESET F	2.2	8.8%	2.1	10.6%
Out-of-Sample RMSE	18		18	
Out-of-Sample MAE	14		14	
Out-of-Sample MAPE	9.17%		9.21%	

Model Discussion

The outlook for Public Authorities is down compared to last year's forecast. This is primarily due to the 2012 to 2013 reduction, and the last historical point being notably lower.

Key drivers of this year's per-day use model are Employment in Other Services sector (Duluth MSA) and Employment in the Construction, Natural Resources, and Mining sector (13 county). Last year's model used Wage Distribution in the 13 county area as the sole economic variable. Minnesota Power's econometric interpretation of the key drivers is as follows: For every 1,000 job increase in Other Services, monthly public authority usage should increase by 63 MWh (2.04 x 31). As the month-to-month change in Construction, Natural Resources, and Mining sector employment increases by 100, monthly usage will increase by 34 MWh (0.011 x 31).

This year's model and last year's model both use a binary variable to indicate the step change that occurred in 2012. This binary variable denotes municipal pumping customers switching to a general service (commercial) rate. The impact to commercial energy sales in insignificant because of the class's size, but this does noticeably affect sales to Public Authorities and must be accounted for.

Weather variables were found to be significant in only four months of the year: February, April, November, and December. This was only after excluding a binary variable for the corresponding months. If the binaries were not excluded, the model would have suggested that weather is insignificant in all months. Minnesota Power's policy regarding weather is to drop binary variables in favor of maintaining weather a predictor because it allows for accurate after-the-fact weather normalization later by the company.

Although this year's model is structurally different and utilizes different weather variables, the statistical quality is highly comparable to last year's model. SIC, R-Squared, in-sample forecast error (traditional MAPE), and out-sample (RMSE) are all fairly close.

The Variance Inflation Factors (VIF) of the binaries and weather variables in this model are fairly high. This phenomenon was noticed in last year's Public Authorities energy sales model as well. On its own, any of these variables are not correlated with any other specific variable, but it does appear that a single variable is highly correlated with all other variables in combination (which is what VIF measures).

Although the high VIF's would indicate some multicollinearity is present, Minnesota Power considers this the optimal model for this dependent variable. All other top models also had high VIFs; the only way to avoid the high VIF's was to exclude the binaries and weather variables. Excluding these variables degraded predictive power and statistical quality, and it's clear that each variable is significant, even after solving for autocorrelation and heteroscedasticity. Therefore, Minnesota Power did not exclude these binaries or weather variables despite the high VIF's.

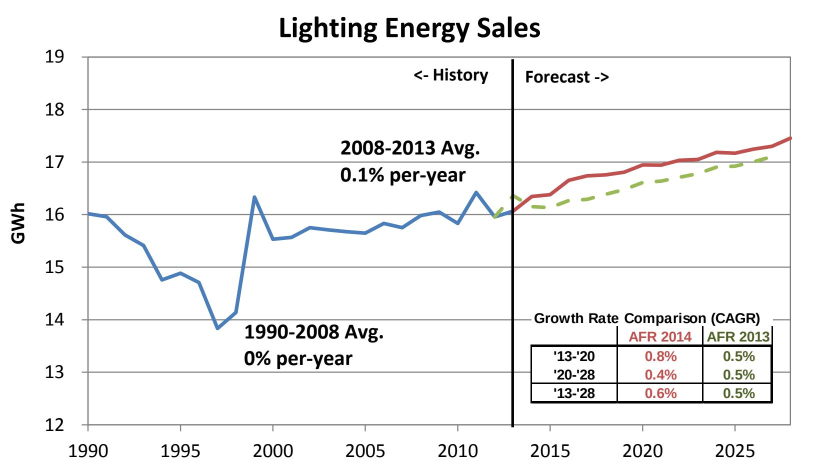
Street Lighting Energy Use - Moderate Growth

Estimation Start/End:	2/1991 - 3/2014
Unit Modeled/Forecast:	Natural Log of Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	3.93	0.00%		0.00%
Binary_Jan	0.03	6.99%	1.83	4.19%
Binary_Feb	(0.05)	0.45%	1.87	1.14%
Binary_Mar	(0.21)	0.00%	1.87	0.00%
Binary_Apr	(0.36)	0.00%	1.84	0.00%
Binary_May	(0.50)	0.00%	1.84	0.00%
Binary_Jun	(0.62)	0.00%	1.84	0.00%
Binary_Jul	(0.59)	0.00%	1.84	0.00%
Binary_Aug	(0.46)	0.00%	1.83	0.00%
Binary_Sep	(0.29)	0.00%	1.84	0.00%
Binary_Oct	(0.17)	0.00%	1.84	0.00%
Binary_Nov	(0.06)	0.21%	1.84	0.10%
Trend	0.00	0.00%	1.19	0.00%
MSA_Pop_diff_lag_12	0.16	0.70%	1.12	9.05%
MSA_RetailTrd_diff_lag_9	0.22	0.35%	1.12	1.32%

	OLS Model	
	MWh	Y/Y Growth
2007	15,752	
2008	15,983	1.5%
2009	16,049	0.4%
2010	15,833	-1.3%
2011	16,420	3.7%
2012	15,955	-2.8%
2013	16,066	0.7%
2014	16,346	**1.7%**
2015	16,380	**0.2%**
2016	16,654	**1.7%**
2017	16,738	**0.5%**
2018	16,755	**0.1%**
2019	16,807	**0.3%**
2020	16,944	**0.8%**
		5 yr CAGR
2025	17,167	***0.3%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	92.2%		93.0%	
AIC	-5.42		-5.52	
SIC	-5.22		-5.30	
MAPE	1.2%		1.1%	
Model F Test	234.2	0.0%	230.8	0.0%
Estimates Residual S.D.	0		0	
SSres	1		1	
Degrees of Freedom	263		261	
Breusch-Pegan F	1.0	41.2%	1.3	23.4%
Breusch-Pegan ChiSq	14.6	40.6%	17.4	23.4%
White's F	1.3	27.7%	2.6	7.8%
Breusch-Godfrey AIC F	4.5	0.0%	2.8	0.0%
Breusch-Godfrey AIC ChiSq	64.6	0.0%	43.6	0.0%
Breusch-Godfrey SIC F	27.4	0.0%	0.0	87.3%
Breusch-Godfrey SIC ChiSq	26.3	0.0%	0.3	59.4%
Durban-Watson	1.3		1.9	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	0.4	52.4%	-0.7	#NUM!
FIT^3 Ramsey's RESET F	0.8	45.8%	0.3	72.2%
FIT^4 Ramsey's RESET F	0.6	64.6%	0.3	86.1%
Out-of-Sample RMSE	0.1		0.1	
Out-of-Sample MAE	0.0		0.0	
Out-of-Sample MAPE	1.34%		1.34%	



Model Discussion

The outlook for energy use by Street Lighting customer is fairly comparable to last year's forecast, but the model utilizes different economic variables as drivers. Key drivers of this year's per-day use model are Population (Duluth MSA) and Employment in the Retail Trade sector (Duluth MSA). Last year's model used Total Personal Income in the 13 county area as the sole economic variable.

Minnesota Power's econometric interpretation of the key drivers is as follows: as the month-to-month change in population increases by 100, street lighting energy sales should increase by 1.6%. As the month-to-month change in retail sector employment increases by 100, street lighting energy sales should increase by 2.2%. Differenced variable appeared to be more indicative of lighting use than any other transformation, suggesting that increases in lighting are driven more by the rate of increase in population than the level of the population.

This year's model and last year's model both use binary variables to indicate the seasonal variation that's left unexplained by economic indicators. This year's model also utilizes a trend variable to account for historical trending.

The AFR 2014 model uses a logged form of the dependent variable, so comparing the statistical quality of this year's and last year's model, which modeled the dependent variable in levels, is difficult. Some metrics such as SIC and AIC or out-sample RMSE cannot be compared. However, in sample and out-sample MAPE show this model is a vast improvement over last year in terms of forecast accuracy: in-sample MAPE decreased to 1.2% from 4% in last year's model, and the out-sample MAPE decreased to 1.3% from 4.5% in last year's model.

The OLS model passed all tests for Heteroskedasticity. ARMA testing of the OLS model solved for autocorrelation to confirm the significance (P-values) of the economic variables' coefficients. Ramsey's RESET F tests prove the current OLS specifications were sufficient; no transformations were likely to improve the model's statistical measures. The very low Variance Inflation Factors (VIF) of each variable proves there is no significant multicollinearity.

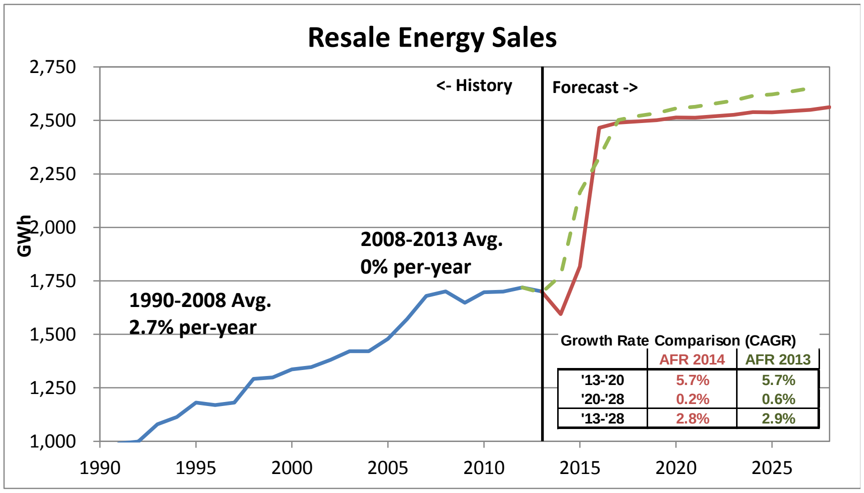
Resale Energy Use - Moderate Growth

Estimation Start/End:	1/1996 - 3/2014
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	3,736.95	0.00%		0.00%
Trend	1.30	0.06%	13.96	0.33%
Binary_Mar	386.28	0.00%	3.09	0.00%
Binary_May	(274.31)	0.00%	4.57	0.00%
Binary_Jun	204.00	1.21%	12.33	10.83%
Binary_Nov	(472.29)	0.73%	57.81	8.91%
Binary_1996-06_2006	(1,504.00)	0.00%	62.41	0.00%
Trend_1996-06_2006	3.93	0.00%	25.42	0.00%
Mar_1996-06_2006	143.01	0.44%	2.97	17.03%
Apr_1996-06_2006	365.50	0.00%	2.18	0.00%
May_1996-06_2006	555.09	0.00%	3.59	0.00%
Jun_1996-06_2006	411.43	0.00%	3.22	0.00%
Jul_1996-06_2006	504.89	0.00%	1.87	0.00%
Aug_1996-06_2006	416.84	0.00%	2.10	0.00%
Sep_1996-06_2006	407.68	0.00%	1.90	0.00%
Oct_1996-06_2006	343.94	0.00%	1.90	0.00%
Nov_1996-06_2006	232.11	0.00%	2.86	0.00%
HDD_Jan	13.74	0.00%	1.93	0.00%
HDD_Feb	14.07	0.00%	2.00	0.00%
CDD_CAC_May	1,538.33	0.02%	1.64	0.17%
HDD_Jun	(30.16)	2.74%	11.35	7.70%
CDD_CAC_Jul	191.32	0.00%	1.29	0.00%
CDD_Aug	81.14	0.00%	1.68	0.00%
HDD_Nov	21.24	0.00%	58.66	0.35%
HDD_Dec	14.05	0.00%	1.80	0.00%
MSA_Unempl_Rate_diff_lag_9	(177.69)	0.23%	1.10	1.95%
MSA_HousStart_LN_diff_lag_4	327.04	0.00%	1.61	0.77%

	OLS Model	
	MWh	Y/Y Growth
2007	1,679,267	
2008	1,701,057	1.3%
2009	1,647,759	-3.1%
2010	1,696,511	3.0%
2011	1,699,644	0.2%
2012	1,718,819	1.1%
2013	1,700,993	-1.0%
2014	1,595,159	**-6.2%**
2015	1,817,456	**13.9%**
2016	2,465,941	**35.7%**
2017	2,489,856	**1.0%**
2018	2,495,882	**0.2%**
2019	2,501,320	**0.2%**
2020	2,513,485	**6.7%**
		5 yr CAGR
2025	2,537,880	*0.2%*

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	96.8%		98.9%	
AIC	9.18		8.13	
SIC	9.60		8.62	
MAPE	1.8%		1.1%	
Model F Test	257.0	0.0%	624.6	0.0%
Estimates Residual S.D.	93		55	
SSres	1,667,166		523,890	
Degrees of Freedom	192		176	
Breusch-Pegan F	1.9	0.7%	1.3	18.7%
Breusch-Pegan ChiSq	45.1	1.1%	32.0	19.3%
White's F	4.0	2.0%	0.1	86.6%
Breusch-Godfrey AIC F	5.8	0.4%	0.0	95.7%
Breusch-Godfrey AIC ChiSq	12.7	0.2%	43.0	0.0%
Breusch-Godfrey SIC F	10.0	0.2%	0.0	95.7%
Breusch-Godfrey SIC ChiSq	11.0	0.1%	43.0	0.0%
Durban-Watson	1.5		2.0	N/A
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	4.9	2.9%	41.9	0.0%
FIT^3 Ramsey's RESET F	2.5	8.6%	28.5	0.0%
FIT^4 Ramsey's RESET F	1.9	13.1%	18.9	0.0%
Out-of-Sample RMSE	108		109	
Out-of-Sample MAE	87		89	
Out-of-Sample MAPE	2.29%		2.30%	



Model Discussion

The outlook for the Sales for Resale customer class is a bit lower than last year's. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions/reductions. Load addition assumptions have changed slightly since last year, but the underlying econometric forecasts is fairly similar after accounting for difference in modeling approach.

As described in the Changes to Database section, Minnesota Power implemented a new modeling methodology to more accurately account for recent changes in the customer class composition. Historical sales to Dahlberg were removed from the historical Resale energy sales series prior to regression since Dahlberg's contract with Minnesota Power ended on December 31st 2013. The resale customer class will be composed of MP's 16 Minnesota municipal customers and Superior Water Light and Power (SWLP) in forecast timeframe, so this is what Minnesota Power modeled and projected. This methodology is explained in the "Methodological Adjustments for the 2014 Forecast" section and specific adjustments made to the historical series are detailed in the "Data Revisions Since Previous AFR" section.

Minnesota Power's econometric interpretation of the key drivers is as follows: as the month-to-month change in the unemployment rate decreases by 0.1, monthly sales for resale should increase by 550 MWh (17.7 x 31). As the month-to-month percent change in housing starts increases by 1%, street monthly sales for resale should increase by about 100 MWh (3.25 x 31). Differenced variable appeared to be more indicative of lighting use than any other transformation, suggesting that increases in lighting are driven more by the rate of increase in population than the level of the population.

The resale model differs from last year's model in its structure and economic drivers. This year's model utilizes the Duluth MSA Unemployment Rate and annualized Housing Starts in the Duluth MSA, whereas last year's model used Employment in Financial Activities (13 county) as the sole economic driver.

Both the AFR 2014 and AFR 2013 models used monthly binaries and trend variables. Both models also account for a structural break in 2006 utilizing binary variables. Last year's model used a full set of alternate binaries to indicate the step-change, whereas this year's model leverages a single binary to serve as the shifted constant and adds to this any significant monthly binaries. This year's model also includes an additional trend variable to distinguish between growth rates in the pre and post structural break timeframe.

The model statistics show the AFR 2014 Resale model is an improvement over last year's. This year's model reduced out-sample RMSE forecast error to 2.29% (from 4.5% in last year's model), reduced SIC, and reduced in-sample MAPE forecast error to 1.8% from 4% in last year's model. ARMA testing of the OLS model was able to resolve heteroscedasticity and autocorrelation to confirm the P-values of each variables coefficient.

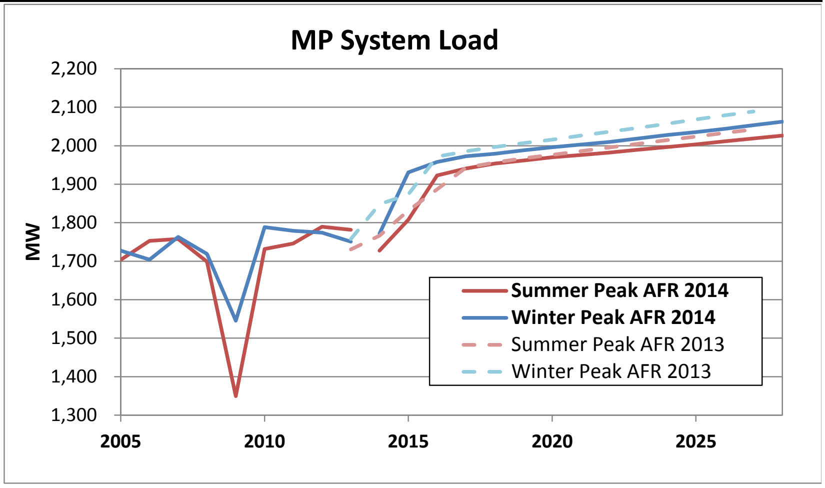
Peak Demand - Moderate Growth

Estimation Start/End:	6/1999 - 3/2014
Unit Modeled/Forecast:	Monthly Peak Demand

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	337.22	0.00%		0.00%
Trend	0.34	0.00%	1.45	0.01%
Weather-normal_MWh-perday	0.04	0.00%	1.96	0.00%
Binary-LP_Coincident	(38.06)	3.05%	1.81	2.92%
Binary-Aug_1999	65.07	6.19%	1.06	4.73%
Binary-Sep_1999	102.55	0.48%	1.13	0.29%
Binary-Nov_1999	97.69	0.60%	1.08	1.53%
Binary-Apr_2000	(87.04)	1.46%	1.10	1.20%
Binary-Oct_2001	(65.13)	7.56%	1.17	21.39%
Binary-Sep_2001	(81.09)	1.84%	1.02	12.67%
Binary-Sep_2002	71.12	3.80%	1.02	0.92%
Binary-Nov_2008	129.04	0.02%	1.03	0.02%
Binary-Dec_2008	149.55	0.00%	1.05	0.00%
Temp_Low-Less_N30	(1.69)	0.00%	1.07	0.00%
Temp_Low-N30_N20	(1.83)	0.00%	1.14	0.00%
Temp_Low-N20_N10	(2.35)	0.00%	1.16	0.00%
Temp_Low-N10_Zero	(1.40)	1.27%	1.26	1.13%
Temp_Low-Zero_20	(1.41)	3.24%	1.06	4.85%
Temp_Avg-T20_30	(1.46)	0.02%	1.38	0.04%
Temp_Avg-T30_40	(1.74)	0.07%	1.08	0.23%
Temp_Avg-T40_50	(1.47)	0.00%	1.25	0.00%
Temp_High-T50_60	(0.77)	0.22%	1.26	0.25%
Temp_High-T70_80	0.20	3.12%	1.49	0.94%
Temp_High-T80_90	0.97	0.00%	1.47	0.00%
Binary-SummerPeak	30.83	0.70%	1.55	2.91%

	Peak Demand (MW)			
	Summer	Y/Y Growth	Winter	Y/Y Growth
2007	1,758		1,763	
2008	1,699	-3.3%	1,719	-2.5%
2009	1,350	-20.6%	1,545	-10.1%
2010	1,732	28.3%	1,789	15.7%
2011	1,746	0.8%	1,779	-0.5%
2012	1,790	2.5%	1,774	-0.3%
2013	1,782	-0.5%	1,751	-1.3%
2014	1,727	**-3.0%**	1,772	**1.2%**
2015	1,807	**4.6%**	1,931	**9.0%**
2016	1,923	**6.4%**	1,958	**1.4%**
2017	1,941	**0.9%**	1,973	**0.8%**
2018	1,954	**0.7%**	1,979	**0.3%**
2019	1,962	**0.4%**	1,988	**0.5%**
2020	1,970	**0.4%**	1,996	**0.4%**
		5 yr CAGR		*5 yr CAGR*
2025	2,004	***0.3%***	**2,035**	***0.4%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	90.4%		91.2%	
AIC	7.16		7.08	
SIC	7.60		7.56	
MAPE	1.7%		1.7%	
Model F Test	70.5	0.0%	71.3	0.0%
Estimates Residual S.D.	34		32	
SSres	172,477		155,002	
Degrees of Freedom	153		150	
Breusch-Pegan F	1.0	45.9%	0.6	91.4%
Breusch-Pegan ChiSq	24.3	44.4%	15.8	89.5%
White's F	1.2	29.8%	0.4	70.4%
Breusch-Godfrey AIC F	11.2	0.1%	0.0	87.7%
Breusch-Godfrey AIC ChiSq	12.2	0.0%	3.2	7.4%
Breusch-Godfrey SIC F	11.2	0.1%	0.0	87.7%
Breusch-Godfrey SIC ChiSq	12.2	0.0%	3.2	7.4%
Durban-Watson	1.5	BAD	2.0	N/A
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	0.6	45.9%	-2.3	#NUM!
FIT^3 Ramsey's RESET F	0.7	48.7%	1.6	20.5%
FIT^4 Ramsey's RESET F	1.9	13.9%	1.1	35.6%
Out-of-Sample RMSE	42		42	
Out-of-Sample MAE	32		32	
Out-of-Sample MAPE	2.30%		2.31%	



Model Discussion

The long-run outlook for Minnesota Power's system peak is a bit lower than last year's due to a decline in the overall energy sales outlook. The short-term (2014-2015) peak demand outlook is noticeably lower due to differences in assumptions for large customer load additions/reductions, but is slightly higher than last year's for a short time in 2016; this is also due to differences in assumptions for large customer load additions/reductions.

Minnesota Power implemented a new modeling methodology to more accurately account for recent changes in the customer class composition. Historical demand was adjusted down by an average of 30 MW over the historical timeframe. This methodology is explained in the "Methodological Adjustments for the 2014 Forecast" section and specific adjustments made to the historical series are detailed in the "Data Revisions Since Previous AFR" section.

Two types of binary variables account for anomalous industrial customer behavior. The "Binary-LP_Coincident" variable denotes a historical peak when a large industrial customer was not operating at the time of the peak. The "Binary-month_year" variables denote months where the model would have realized sizable errors that could have biased the coefficients of other predictor variables.

The binary variable ("Binary-SummerPeak") notes historical summer peaks to avoid understating summer peak demand in the forecast timeframe.

Temperature variables play an important role in both this and last year's model though the definitions and structure of these variables has been improved; this is noted in the "Methodological Adjustments for the 2014 Forecast" section.

This year's model utilizes a different dependent variable than last year, so comparison of statistical quality should be done using forecast errors instead of SIC or R-squared. This year's model has an out-sample MAPE of 2.3% (compared to 2.1% in last year's model) and the in-sample increased to 1.7% from 1.3% in last year's model. The OLS model shows no signs of heteroscedasticity.

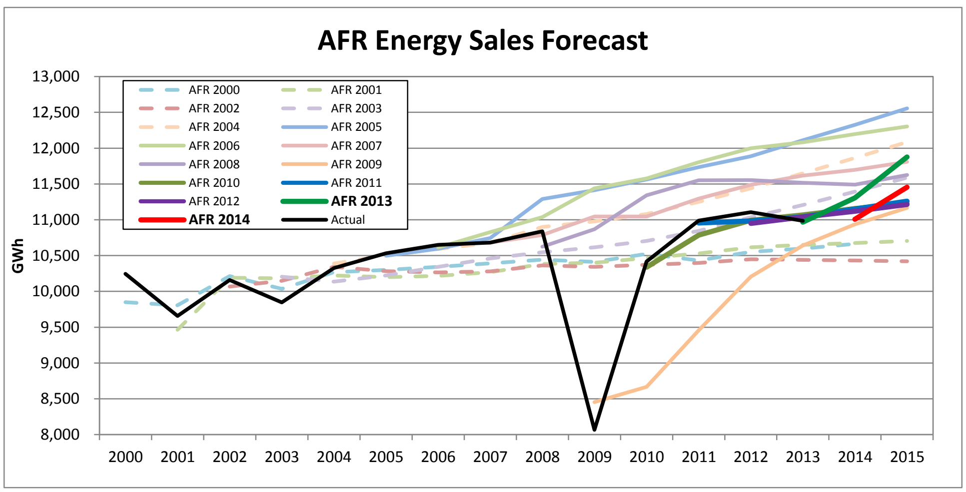
ARMA testing of the OLS model was able to resolve autocorrelation to confirm the P-values of each variable's coefficient with the exception of two "Binary-month_year" variables which only achieved an 80% and 88% level of significance. Each of these binary variables denotes a single month in the early forecast timeframe containing erratic load behavior and their exclusion from the model could bias coefficients of the temperature variables. Therefore, the decision was made to let them remain in the OLS model.

F. Confidence in Forecast & Historical Accuracy

Over the longer term, the IHS Global Insight macroeconomic outlook has converged on slow, steady growth in the major indicators. Despite the recent strong sales climate for iron and steel, a weaker economic outlook makes Minnesota Power's energy sales to those sectors vulnerable. The potential for substantial regional growth as a result of mineral development indicates the value of examining alternatives. Minnesota Power will continue to evaluate the status of key industrial and wholesale developments in its service territory to determine the most appropriate scenario on which to develop plans.

Minnesota Power has a solid track record of accurate forecasting. Figures 12-14 show Minnesota Power's past AFR forecast accuracy for aggregate energy use, Summer Peak, and Winter Peak demand. The bottom values in each column (**Bold**) represent the forecast accuracy in the current year, or the year it was produced. For example, the lower right value of -0.2 percent is the difference between the forecast produced in 2013 (AFR 2013) and the 2013 year-end actual. Similarly, the cell just above the current year accuracy (***Bold, Italic***) represents the accuracy of the forecast in the year immediately after its formulation. For example, AFR 2012 (formulated in 2012) forecast of 2013 was 0.5 percent (54 GWh) above the actual.

Figure 12: AFR Energy Sales Forecast Accuracy

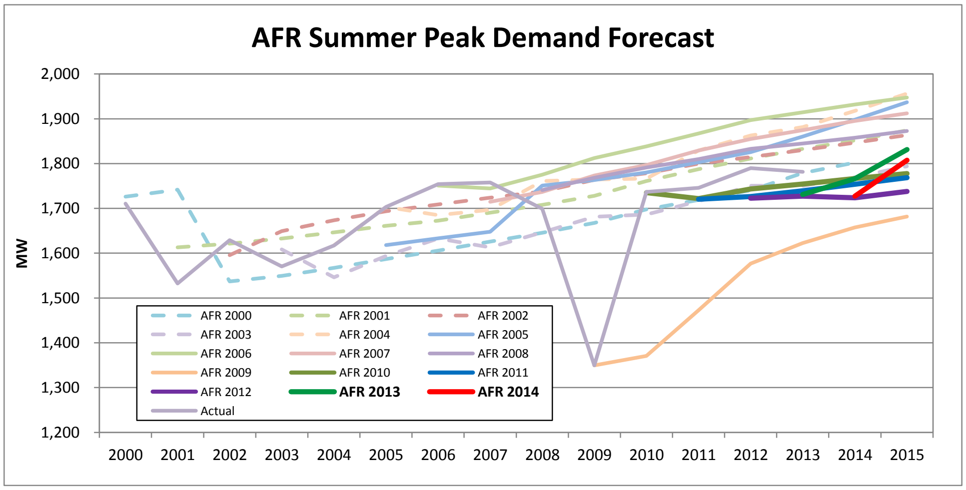


Total Energy Sales Forecast Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Average Error of AFR	Avg. Error Year-Ahead
AFR 2000	**-3.9%**	***1.5%***	0.5%	1.9%	-0.6%	**-2.2%**	-2.9%	-2.7%	-3.7%	29.1%	1.0%	-5.1%	-5.0%	-3.5%	0.3%	1.5%
AFR 2001		**-2.0%**	***0.3%***	3.4%	-1.0%	-3.1%	**-4.1%**	-3.9%	-4.2%	29.0%	0.5%	-4.2%	-4.4%	-3.1%	0.2%	0.3%
AFR 2002			**-0.9%**	***3.1%***	0.2%	-2.4%	-3.6%	**-3.8%**	-4.4%	28.2%	-0.4%	-5.4%	-5.9%	-5.0%	0.0%	3.1%
AFR 2003				**3.6%**	***-1.8%***	-2.9%	-2.9%	-2.1%	**-2.7%**	31.6%	2.8%	-1.3%	-0.6%	2.0%	2.3%	1.8%
AFR 2004					**0.6%**	***-0.3%***	-0.5%	0.0%	0.6%	**36.1%**	6.4%	2.4%	3.0%	6.0%	5.4%	0.3%
AFR 2005						**-0.3%**	***-0.5%***	0.6%	4.1%	41.5%	**11.0%**	6.8%	7.0%	10.2%	8.9%	0.5%
AFR 2006							**-0.3%**	***1.4%***	1.8%	41.8%	11.1%	**7.4%**	8.0%	10.0%	10.2%	1.4%
AFR 2007								**0.0%**	***-0.5%***	37.0%	6.0%	2.8%	**3.4%**	5.7%	7.8%	0.5%
AFR 2008									**-2.0%**	***34.8%***	8.9%	5.1%	4.0%	**4.8%**	9.3%	34.8%
AFR 2009										**4.8%**	***-16.8%***	-13.9%	-8.1%	-3.1%	-7.4%	16.8%
AFR 2010											**-0.8%**	***-1.8%***	-1.0%	0.7%	-0.7%	1.8%
AFR 2011												**-0.3%**	***-1.1%***	0.5%	-0.3%	1.1%
AFR 2012													**-1.4%**	***0.5%***	-0.5%	0.5%
AFR 2013														**-0.2%**	-0.2%	

N.n%	= *Year-Ahead Foreast*	Avg Year-Ahead Error =	1.4%
N.n%	= Current Year Forecast	Avg Current Year Error =	-0.2%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	5.6%

Figure 13: AFR Summer Peak Demand Forecast Accuracy



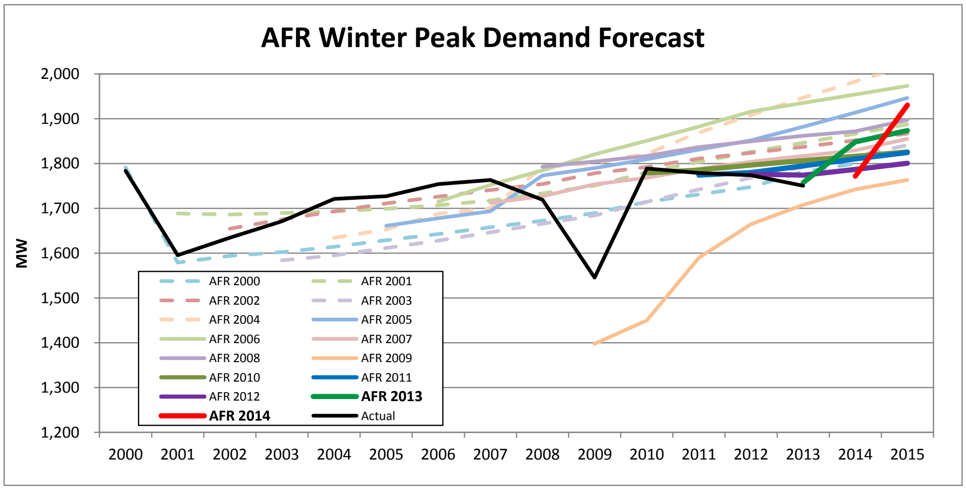
Summer System Peak Error

Forecast

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	**Average Error of AFR**	**Avg. Error Year-Ahead**
AFR 2000	**0.9%**	***13.7%***	-5.6%	-1.3%	-3.1%	**-6.8%**	-8.5%	-7.5%	-3.1%	23.6%	-2.2%	-1.6%	-2.8%	-0.2%	-0.3%	13.7%
AFR 2001		**5.2%**	***-0.5%***	4.0%	1.8%	-2.5%	**-4.6%**	-3.8%	0.5%	28.0%	1.4%	2.4%	1.2%	2.9%	2.8%	0.5%
AFR 2002			**-2.0%**	***5.0%***	3.5%	-0.6%	-2.6%	**-1.9%**	2.3%	30.7%	2.4%	3.1%	1.4%	2.7%	3.7%	5.0%
AFR 2003				**2.4%**	***-4.4%***	-6.4%	-6.9%	-8.2%	**-3.1%**	24.6%	-2.9%	-1.7%	-2.2%	-1.7%	-1.0%	4.4%
AFR 2004					**0.0%**	***0.0%***	-3.9%	-3.5%	3.7%	**30.8%**	1.7%	4.8%	4.1%	5.6%	4.3%	0.0%
AFR 2005						**-5.0%**	***-6.9%***	-6.3%	3.1%	30.7%	**2.5%**	3.3%	2.0%	4.4%	3.1%	6.9%
AFR 2006							**-0.2%**	***-0.7%***	4.5%	34.3%	5.9%	**7.0%**	6.0%	7.5%	8.0%	0.7%
AFR 2007								**-2.4%**	***2.2%***	31.4%	3.5%	4.8%	**3.6%**	5.2%	6.9%	2.2%
AFR 2008									**2.5%**	***31.0%***	3.2%	3.7%	2.4%	**3.6%**	7.7%	31.0%
AFR 2009										**0.0%**	***-21.1%***	-15.6%	-11.9%	-8.9%	-11.5%	21.1%
AFR 2010											**-0.1%**	***-1.4%***	-2.6%	-1.5%	-1.4%	1.4%
AFR 2011												**-1.5%**	***-3.5%***	-2.4%	-2.4%	3.5%
AFR 2012													**-3.7%**	***-3.0%***	-3.4%	3.0%
AFR 2013														**-2.8%**	-2.8%	

N.n%	*= Year-Ahead Forecast*	Avg Year-Ahead Error =	0.8%
N.n%	= Current Year Forecast	Avg Current Year Error =	-0.5%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	3.4%

Figure 14: AFR Winter Peak Demand Forecast Accuracy



Winter System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Average Error of AFR	Avg. Error Year-Ahead
AFR 2000	**4.7%**	***3.0%***	-2.2%	2.0%	-0.2%	**-4.4%**	-6.4%	-5.7%	-1.6%	25.2%	-1.3%	-0.9%	-2.3%	0.0%	0.7%	3.0%
AFR 2001		**10.2%**	***3.5%***	7.6%	4.7%	-0.3%	**-2.7%**	-2.3%	2.0%	29.7%	2.6%	3.3%	2.0%	3.6%	4.9%	3.5%
AFR 2002			**1.6%**	***6.7%***	4.7%	0.4%	-1.6%	**-1.0%**	3.2%	31.8%	3.2%	3.7%	1.9%	3.1%	4.8%	6.7%
AFR 2003				**0.9%**	***-1.4%***	-5.4%	-7.2%	-6.3%	**-2.0%**	24.8%	-1.3%	-0.2%	-1.2%	0.6%	0.1%	1.4%
AFR 2004					**1.1%**	***-3.0%***	-3.8%	-3.3%	5.4%	**33.5%**	4.9%	7.1%	6.6%	9.3%	5.8%	3.0%
AFR 2005						**-2.5%**	***-4.3%***	-3.6%	4.4%	32.6%	**4.2%**	4.9%	3.5%	5.6%	5.0%	4.3%
AFR 2006							**-2.2%**	***-0.3%***	5.0%	34.9%	6.6%	**7.8%**	7.0%	8.6%	8.4%	0.3%
AFR 2007								**-2.6%**	***1.7%***	29.9%	1.8%	2.4%	**0.8%**	2.0%	5.1%	1.7%
AFR 2008									**5.5%**	***33.7%***	4.6%	5.2%	3.3%	**4.5%**	9.5%	33.7%
AFR 2009										**3.6%**	***-16.5%***	-8.9%	-7.0%	-4.1%	-6.6%	16.5%
AFR 2010											**2.4%**	***2.3%***	0.4%	1.4%	1.6%	2.3%
AFR 2011												**1.6%**	***-0.6%***	0.7%	0.6%	0.6%
AFR 2012													**-0.7%**	***-0.4%***	-0.6%	0.4%
AFR 2013														**-1.3%**	-1.3%	

N.n%	= *Year-Ahead Foreast*	Avg Year-Ahead Error =	1.9%
N.n%	= Current Year Forecast	Avg Current Year Error =	1.6%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	4.5%

2. AFR 2014 Forecast and Alternative Scenarios

A. Forecast Scenario Descriptions

Minnesota Power's developed several scenarios for system peak demand and energy forecasts. All scenarios assume some direct load additions and/or losses from specific Industrial customers, served directly by Minnesota Power or through a wholesale customer.

Moderate Growth Demand and Energy Scenario

This scenario includes changes in customer operations that are not certain, but have a high likelihood of occurring. This high likelihood is characterized by formal communication from the customer, plus one or more of the following:

- An Electric Service Agreement is either executed or is in negotiation;
- The change in operation is supported by customer actions, such as construction or investment that will result in additional power requirements;
- A timeframe for the operation and resulting power.

Moderate Growth scenario assumes additional load from a number of new and existing customers. Most notably, this scenario accounts for a new industrial facility to be served by a Minnesota Power wholesale customer, the City of Nashwauk. The facility is expected to reach full demand in early 2016; this is a more accelerated ramp-up than has been assumed in previous Minnesota Power forecasts, but is constant with what this customer has communicated publicly.

The scenario assumes a moderate, or "expected," rate of national economic growth as the basis for the regional economic model.

The Moderate Growth scenario results in average annual energy sales growth and average annual peak demand growth of 1.1 percent and 1.1 percent, respectively, from 2014 through 2028.

Moderate Growth with Deferred Resale Demand and Energy Scenario

This scenario is identical to the Moderate Growth scenario except it assumes a one-year deferment in the start-up of the new industrial facility in the City of Nashwauk. The facility is expected to reach full demand in early 2017 instead of early 2016 (as is assumed in the Moderate Growth scenario). Other possible additional phases of this project are not included in this scenario.

The scenario assumes a moderate, or "expected," rate of national economic growth as the basis for the regional economic model.

The Moderate Growth with Deferred resale scenario results in average annual energy sales growth and average annual peak demand growth of 1.1 percent and 1.1 percent, respectively, from 2014 through 2028.

Current Contract Demand and Energy Scenario

This case reflects the results of the econometric models, with discrete adjustments for announced changes in demand with a specific starting date. Examples of these adjustments are executed and approved electric service agreements, expiring electric service agreements that will not be renewed, and publicly communicated schedules by prospective customers.

The largest of the adjustments to the econometric forecast accounts for the new industrial facility served by a Minnesota Power wholesale customer, the City of Nashwauk. The facility is expected to reach full demand in early 2016; this is a more accelerated ramp-up than has been assumed in previous Minnesota Power forecasts, but is constant with what this customer has communicated publicly.

This scenario is more constrained in its additions for new prospective customers and results in average annual energy sales growth and average annual peak demand growth of 0.8 percent and 0.8 percent, respectively, from 2014 through 2028.

The scenario assumes a moderate, or "expected," rate of national economic growth as the basis for the regional economic model.

Potential Upside Demand and Energy Scenario

In this scenario, customer-specific additions are added to those in the Moderate Growth scenario. These additions have a moderate likelihood of occurring in the next 5 years, and have been publicly communicated as potential additions. This results in average annual energy sales growth and average annual peak demand growth of 1.6 percent and 1.5 percent, respectively, from 2014 through 2028. The results are presented in the Potential Upside table.

The scenario assumes a moderate, or "expected," rate of national economic growth as the basis for the regional economic model.

Potential Downside Demand and Energy Scenario

Minnesota Power has also developed a scenario reflecting plausible permanent capacity reductions by specific customers in the next 5 years. This scenario includes some additions, but these are more than offset by substantial load reductions resulting in no energy or demand growth in the 2014-2028 timeframe. The results are presented in the Potential Upside table.

The scenario assumes a slow, or "pessimistic," rate of national economic growth as the basis for the regional economic model.

Best Case Demand and Energy Scenario

This scenario adds customer-specific impacts in addition to those in the Moderate Growth and Potential Upside scenarios above. The additions in this scenario are possible, but speculative, requiring highly favorable economic conditions.

The peak and energy impacts are identified in the Best Case table, which show average annual energy sales growth and average annual peak demand growth of 3 percent and 2.4 percent, respectively, from 2014 through 2028.

The scenario assumes an accelerated, or "optimistic," rate of national economic growth as the basis for the regional economic model.

B. Other Adjustments to Econometric Forecast

Each of Minnesota Power's forecast scenarios is the summation of the econometric model results and arithmetic adjustments for impacts which cannot be accurately modeled. These exogenous impacts are documented as separate seasonal peak and energy adjustments in all of the specific scenario tables. These adjustments fall into the following categories:

1. **Net Load/Energy Added**: are exogenous adjustments accounting for added load due to new customers or expansion by existing customers, and lost load due to closure or loss of contract. To preserve customer confidentiality, the seasonal demand and energy impacts are netted to a single value before being applied to the econometric values. Adjustments made for recent customer additions (as discussed in sections on *Methodological Improvements* and *Data Revisions Since Previous AFR*) are also included in this value.

2. **Customer Generation:** is the demand on Minnesota Power system that is met by customer owned generation. Customer generation can fluctuate without clear economic causes so this component of Minnesota Power system peak is removed to more accurately model demand for an econometric forecast. The process for this adjustment can be outlined in 3 steps:

    - Remove Customer Generation from the historical peak series.
    - Econometrically project a less volatile "FERC load coincident w/ Monthly Minnesota Power System peak (MW)" monthly peak series.
    - Arithmetically account for Customer Generation after forecasting.

    This procedure has been a methodological staple of Minnesota Power forecasting for over a decade and increases the quality of the econometric processes and resulting forecasts.

    The forecast assumption for customer generation is determined by averaging the historical customer generation coincident with the monthly peak over a 12-year historical timeframe. The result is a set of 12 distinct monthly values for each month of the year. The MWh adjustment is determined similarly through averaging the most recent 12-year historical timeframe, but excluding 2009 due to its irregularly low value. These adjustments are credits that increase the estimated peaks and system energy use projection by the estimated amount.

This Customer Generation adjustment to peak and energy forecasts also accounts for expected changes in the operation or ownership of generating assets that would affect deliveries to customers.

3. **Dual Fuel**: Minnesota Power has a robust Dual Fuel program for Residential and Commercial customers. Dual Fuel impacts are accounted for in forecast in the same way as conservation. The impacts of historical interruptions are assumed to be inherent in the forecast since curtailments affected historical monthly peak demand. Post-regression adjustments for dual fuel would produce an artificially low peak demand forecast. Minnesota Power will account for dual fuel interruption as a resource and not as an adjustment to the load forecast.

C. Peak Demand and Energy Outlooks by Scenario

i. Moderate Growth Scenario – AFR Expected Case

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,584	1,534	169	170	1,753	1,704	1,753	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,526	1,554	30	45	**1,556**	**1,599**	172	173	**1,727**	**1,772**	***1,772***	2014
2015	1,543	1,563	93	176	**1,636**	**1,739**	172	192	**1,807**	**1,931**	***1,931***	**2015**
2016	1,551	1,573	171	183	**1,722**	**1,756**	201	202	**1,923**	**1,958**	***1,958***	2016
2017	1,557	1,578	183	193	**1,740**	**1,771**	201	202	**1,941**	**1,973**	***1,973***	2017
2018	1,560	1,584	193	194	**1,753**	**1,777**	201	202	**1,954**	**1,979**	***1,979***	2018
2019	1,567	1,593	194	194	**1,761**	**1,786**	201	202	**1,962**	**1,988**	***1,988***	2019
2020	1,576	1,601	194	194	**1,769**	**1,794**	201	202	**1,970**	**1,996**	***1,996***	**2020**
2021	1,582	1,608	194	194	**1,775**	**1,801**	201	202	**1,976**	**2,003**	***2,003***	2021
2022	1,588	1,614	194	194	**1,782**	**1,808**	201	202	**1,982**	**2,010**	***2,010***	2022
2023	1,595	1,624	194	194	**1,789**	**1,817**	201	202	**1,990**	**2,019**	***2,019***	2023
2024	1,602	1,632	194	194	**1,796**	**1,826**	201	202	**1,997**	**2,028**	***2,028***	2024
2025	1,609	1,640	194	194	**1,803**	**1,834**	201	202	**2,004**	**2,035**	***2,035***	**2025**
2026	1,617	1,648	194	194	**1,810**	**1,842**	201	202	**2,011**	**2,044**	***2,044***	2026
2027	1,625	1,658	194	194	**1,818**	**1,851**	201	202	**2,019**	**2,053**	***2,053***	2027
2028	1,632	1,667	194	194	**1,826**	**1,861**	201	202	**2,027**	**2,063**	***2,063***	2028

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	*Load Factor*	
2000			10,243,434					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	*1,636*	*0.79*	2002
2003			9,846,294	1,232,635	11,078,929	*1,671*	*0.76*	2003
2004			10,324,412	1,267,728	11,592,140	*1,721*	*0.77*	2004
2005			10,531,271	1,258,895	11,790,166	*1,727*	*0.78*	2005
2006			10,649,101	1,195,070	11,844,171	*1,753*	*0.77*	2006
2007			10,680,509	1,252,965	11,933,474	*1,763*	*0.77*	2007
2008			10,839,446	1,276,158	12,115,604	*1,719*	*0.80*	2008
2009			8,065,090	1,108,014	9,173,104	*1,545*	*0.68*	2009
2010			10,417,422	1,299,292	11,716,714	*1,789*	*0.75*	2010
2011			10,988,200	1,422,107	12,410,307	*1,779*	*0.80*	2011
2012			11,107,358	1,200,317	12,307,675	*1,790*	*0.78*	2012
2013	10,985,809		10,985,809	1,185,139	12,170,948	*1,782*	*0.78*	2013
2014	10,808,480	197,504	**11,005,984**	1,251,630	**12,257,614**	***1,772***	***0.79***	2014
2015	10,819,622	635,938	**11,455,560**	1,286,450	**12,742,010**	***1,931***	***0.75***	**2015**
2016	10,906,285	1,304,421	**12,210,706**	1,422,746	**13,633,452**	***1,958***	***0.79***	2016
2017	10,926,100	1,213,426	**12,139,526**	1,462,483	**13,602,010**	***1,973***	***0.79***	2017
2018	10,939,368	1,286,636	**12,226,004**	1,462,483	**13,688,488**	***1,979***	***0.79***	2018
2019	10,987,659	1,294,783	**12,282,442**	1,462,483	**13,744,926**	***1,988***	***0.79***	2019
2020	11,074,743	1,298,331	**12,373,073**	1,466,490	**13,839,563**	***1,996***	***0.79***	**2020**
2021	11,088,873	1,294,783	**12,383,656**	1,462,483	**13,846,140**	***2,003***	***0.79***	2021
2022	11,134,063	1,294,783	**12,428,847**	1,462,483	**13,891,330**	***2,010***	***0.79***	2022
2023	11,188,371	1,294,783	**12,483,154**	1,462,483	**13,945,637**	***2,019***	***0.79***	2023
2024	11,267,085	1,298,331	**12,565,416**	1,466,490	**14,031,906**	***2,028***	***0.79***	2024
2025	11,293,034	1,294,783	**12,587,817**	1,462,483	**14,050,301**	***2,035***	***0.79***	**2025**
2026	11,351,103	1,294,783	**12,645,886**	1,462,483	**14,108,370**	***2,044***	***0.79***	2026
2027	11,411,239	1,294,783	**12,706,022**	1,462,483	**14,168,506**	***2,053***	***0.79***	2027
2028	11,503,999	1,298,331	**12,802,330**	1,466,490	**14,268,820**	***2,063***	***0.79***	2028

Customer Count Forecast by Class

Year	Residential	Commercial	Industrial	Street Lighting	Public Authorities	Resale	Total
2005	116,072	20,040	460	490	233	18	137,313
2006	117,596	20,419	451	509	237	18	139,229
2007	118,870	20,630	435	548	241	18	140,742
2008	119,300	20,969	431	585	246	18	141,549
2009	121,217	21,287	429	422	262	18	143,636
2010	121,235	21,491	424	438	278	18	143,884
2011	121,251	21,603	421	503	281	18	144,077
2012	120,697	21,614	411	539	275	18	143,554
2013	**121,314**	**21,915**	**403**	**592**	**287**	**18**	**144,529**
2014	**120,818**	**21,921**	**387**	**664**	**281**	**17**	**144,089**
2015	**123,065**	**22,376**	**380**	**726**	**290**	**17**	**146,854**
2016	**124,243**	**22,644**	**378**	**789**	**293**	**17**	**148,365**
2017	**125,202**	**22,928**	**382**	**854**	**297**	**17**	**149,681**
2018	**125,997**	**23,205**	**384**	**910**	**300**	**17**	**150,813**
2019	**126,542**	**23,469**	**385**	**964**	**302**	**17**	**151,680**
2020	**127,136**	**23,749**	**385**	**1,015**	**304**	**17**	**152,606**
2021	**127,633**	**24,021**	**387**	**1,063**	**306**	**17**	**153,426**
2022	**128,132**	**24,293**	**386**	**1,112**	**307**	**17**	**154,247**
2023	**128,562**	**24,564**	**385**	**1,158**	**309**	**17**	**154,995**
2024	**128,983**	**24,833**	**383**	**1,204**	**310**	**17**	**155,729**
2025	**129,353**	**25,107**	**381**	**1,250**	**311**	**17**	**156,419**
2026	**129,873**	**25,385**	**377**	**1,294**	**312**	**17**	**157,258**
2027	**130,433**	**25,664**	**374**	**1,341**	**313**	**17**	**158,142**
2028	**131,060**	**25,946**	**369**	**1,388**	**315**	**17**	**159,094**

Energy Sales Forecast (MWh) by Customer Class

Year	Residential	Commercial	Industrial	Street Lighting	Public Authorities	Resale	Total
2005	1,013,156	1,200,075	6,761,669	15,646	61,396	1,479,329	10,531,271
2006	1,011,699	1,206,607	6,782,975	15,831	60,882	1,571,107	10,649,101
2007	1,051,453	1,244,930	6,622,051	15,752	67,056	1,679,267	10,680,509
2008	1,079,837	1,240,324	6,737,333	15,983	64,912	1,701,057	10,839,446
2009	1,075,116	1,212,778	4,051,352	16,049	62,036	1,647,759	8,065,090
2010	1,057,476	1,221,754	6,364,080	15,833	61,768	1,696,511	10,417,422
2011	1,069,856	1,226,174	6,913,648	16,420	62,458	1,699,644	10,988,200
2012	1,043,281	1,237,386	7,037,843	15,955	54,074	1,718,819	11,107,358
2013	**1,086,481**	**1,256,540**	**6,873,992**	**16,066**	**51,736**	**1,700,993**	**10,985,809**
2014	**1,126,533**	**1,284,024**	**6,929,749**	**16,346**	**54,172**	**1,595,159**	**11,005,984**
2015	**1,101,872**	**1,287,245**	**7,177,641**	**16,380**	**54,967**	**1,817,456**	**11,455,560**
2016	**1,117,148**	**1,310,008**	**7,242,366**	**16,654**	**56,293**	**2,468,238**	**12,210,706**
2017	**1,124,315**	**1,326,212**	**7,125,775**	**16,738**	**56,630**	**2,489,856**	**12,139,526**
2018	**1,135,933**	**1,343,242**	**7,177,287**	**16,755**	**56,906**	**2,495,882**	**12,226,004**
2019	**1,144,295**	**1,357,620**	**7,205,498**	**16,807**	**56,903**	**2,501,320**	**12,282,442**
2020	**1,156,269**	**1,375,938**	**7,253,307**	**16,944**	**57,131**	**2,513,485**	**12,373,073**
2021	**1,161,158**	**1,388,599**	**7,247,011**	**16,941**	**57,266**	**2,512,682**	**12,383,656**
2022	**1,170,667**	**1,404,045**	**7,260,144**	**17,035**	**57,401**	**2,519,554**	**12,428,847**
2023	**1,179,077**	**1,419,552**	**7,283,882**	**17,051**	**57,571**	**2,526,019**	**12,483,154**
2024	**1,189,847**	**1,439,572**	**7,321,726**	**17,183**	**57,798**	**2,539,290**	**12,565,416**
2025	**1,194,569**	**1,453,153**	**7,327,251**	**17,167**	**57,797**	**2,537,880**	**12,587,817**
2026	**1,203,301**	**1,468,463**	**7,355,298**	**17,247**	**58,054**	**2,543,524**	**12,645,886**
2027	**1,212,603**	**1,484,940**	**7,383,313**	**17,298**	**58,370**	**2,549,498**	**12,706,022**
2028	**1,226,285**	**1,505,777**	**7,432,043**	**17,454**	**58,896**	**2,561,875**	**12,802,330**

ii. Moderate Growth with Deferred Resale

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,584	1,534	169	170	1,753	1,704	1,753	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,525	1,554	30	45	1,555	1,599	172	173	1,727	1,771	1,771	2014
2015	1,543	1,564	63	66	1,606	1,629	172	192	1,778	1,821	1,821	**2015**
2016	1,550	1,573	91	183	1,641	1,755	201	202	1,842	1,957	1,957	2016
2017	1,557	1,578	183	193	1,740	1,770	201	202	1,940	1,972	1,972	2017
2018	1,560	1,584	193	194	1,752	1,777	201	202	1,953	1,979	1,979	2018
2019	1,567	1,593	194	194	1,760	1,786	201	202	1,961	1,988	1,988	2019
2020	1,575	1,600	194	194	1,769	1,794	201	202	1,970	1,996	1,996	**2020**
2021	1,581	1,607	194	194	1,775	1,801	201	202	1,976	2,002	2,002	2021
2022	1,588	1,614	194	194	1,781	1,807	201	202	1,982	2,009	2,009	2022
2023	1,595	1,623	194	194	1,788	1,817	201	202	1,989	2,019	2,019	2023
2024	1,602	1,632	194	194	1,795	1,825	201	202	1,996	2,027	2,027	2024
2025	1,609	1,640	194	194	1,802	1,833	201	202	2,003	2,035	2,035	**2025**
2026	1,616	1,648	194	194	1,810	1,842	201	202	2,011	2,043	2,043	2026
2027	1,624	1,658	194	194	1,818	1,851	201	202	2,019	2,053	2,053	2027
2028	1,632	1,667	194	194	1,825	1,860	201	202	2,026	2,062	2,062	2028

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	Load Factor	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	1,636	0.79	2002
2003			9,846,294	1,232,635	11,078,929	1,671	0.76	2003
2004			10,324,412	1,267,728	11,592,140	1,721	0.77	2004
2005			10,531,272	1,258,895	11,790,167	1,727	0.78	2005
2006			10,649,101	1,195,070	11,844,171	1,753	0.77	2006
2007			10,680,514	1,252,965	11,933,479	1,763	0.77	2007
2008			10,839,446	1,276,158	12,115,604	1,719	0.80	2008
2009			8,065,088	1,108,014	9,173,102	1,545	0.68	2009
2010			10,417,414	1,299,292	11,716,706	1,789	0.75	2010
2011			10,988,200	1,422,107	12,410,307	1,779	0.80	2011
2012			11,107,357	1,200,317	12,307,674	1,790	0.78	2012
2013	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,805,856	197,504	11,003,360	1,251,630	12,254,990	1,771	0.79	2014
2015	10,821,199	415,559	11,236,758	1,286,450	12,523,209	1,821	0.79	**2015**
2016	10,906,880	684,171	11,591,051	1,422,746	13,013,797	1,957	0.76	2016
2017	10,921,738	1,213,426	12,135,164	1,462,483	13,597,648	1,972	0.79	2017
2018	10,935,511	1,286,636	12,222,147	1,462,483	13,684,631	1,979	0.79	2018
2019	10,983,504	1,294,783	12,278,287	1,462,483	13,740,771	1,988	0.79	2019
2020	11,070,561	1,298,331	12,368,891	1,466,490	13,835,381	1,996	0.79	**2020**
2021	11,084,747	1,294,783	12,379,530	1,462,483	13,842,013	2,002	0.79	2021
2022	11,129,622	1,294,783	12,424,405	1,462,483	13,886,888	2,009	0.79	2022
2023	11,184,381	1,294,783	12,479,164	1,462,483	13,941,647	2,019	0.79	2023
2024	11,262,953	1,298,331	12,561,284	1,466,490	14,027,774	2,027	0.79	2024
2025	11,288,653	1,294,783	12,583,436	1,462,483	14,045,919	2,035	0.79	**2025**
2026	11,346,690	1,294,783	12,641,473	1,462,483	14,103,957	2,043	0.79	2026
2027	11,406,825	1,294,783	12,701,608	1,462,483	14,164,091	2,053	0.79	2027
2028	11,499,273	1,298,331	12,797,604	1,466,490	14,264,094	2,062	0.79	2028

iii. **Current Contract Scenario**

Peak Forecast (MW)

	Econometric		+ Net Load Added		= **MP Delivered Load**		+ Customer Gen.		= **MP System Peak**			
	Sum	Win	Sum	Win	**Sum**	**Win**	Sum	Win	**Sum**	**Win**	*Annual*	
2000					1,469	1,503	242	281	1,711	1,784	*1,784*	2000
2001					1,383	1,421	150	175	1,533	1,595	*1,595*	2001
2002					1,464	1,456	165	180	1,629	1,636	*1,636*	2002
2003					1,408	1,496	163	175	1,570	1,671	*1,671*	2003
2004					1,449	1,533	168	189	1,617	1,721	*1,721*	2004
2005					1,535	1,555	169	172	1,703	1,727	*1,727*	2005
2006					1,584	1,534	169	170	1,753	1,704	*1,753*	2006
2007					1,582	1,584	176	179	1,758	1,763	*1,763*	2007
2008					1,552	1,575	147	145	1,699	1,719	*1,719*	2008
2009					1,200	1,369	150	176	1,350	1,545	*1,545*	2009
2010					1,591	1,599	140	190	1,732	1,789	*1,789*	2010
2011					1,573	1,629	173	150	1,746	1,779	*1,779*	2011
2012					1,603	1,605	187	169	1,790	1,774	*1,790*	2012
2013					1,645	1,589	136	162	1,782	1,751	*1,782*	2013
2014	1,525	1,553	30	32	**1,555**	**1,585**	172	173	**1,727**	**1,758**	***1,758***	2014
2015	1,543	1,564	70	122	**1,613**	**1,686**	172	177	**1,784**	**1,862**	***1,862***	**2015**
2016	1,550	1,573	110	118	**1,660**	**1,691**	176	183	**1,836**	**1,874**	***1,874***	2016
2017	1,557	1,578	118	118	**1,675**	**1,696**	182	183	**1,856**	**1,879**	***1,879***	2017
2018	1,559	1,583	118	118	**1,677**	**1,701**	182	183	**1,859**	**1,884**	***1,884***	2018
2019	1,567	1,592	118	118	**1,685**	**1,710**	182	183	**1,867**	**1,893**	***1,893***	2019
2020	1,575	1,600	118	118	**1,693**	**1,718**	182	183	**1,875**	**1,901**	***1,901***	**2020**
2021	1,581	1,607	118	118	**1,699**	**1,725**	182	183	**1,881**	**1,908**	***1,908***	2021
2022	1,587	1,613	118	118	**1,705**	**1,731**	182	183	**1,887**	**1,914**	***1,914***	2022
2023	1,594	1,623	118	118	**1,712**	**1,741**	182	183	**1,894**	**1,924**	***1,924***	2023
2024	1,601	1,631	118	118	**1,719**	**1,749**	182	183	**1,901**	**1,932**	***1,932***	2024
2025	1,608	1,639	118	118	**1,726**	**1,757**	182	183	**1,908**	**1,940**	***1,940***	**2025**
2026	1,616	1,647	118	118	**1,734**	**1,765**	182	183	**1,916**	**1,948**	***1,948***	2026
2027	1,623	1,657	118	118	**1,741**	**1,775**	182	183	**1,923**	**1,958**	***1,958***	2027
2028	1,631	1,666	118	118	**1,749**	**1,784**	182	183	**1,931**	**1,967**	***1,967***	2028

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= **MP Delivered Energy**	+ Customer Gen.	= **System Energy Use**	**MP System**		
						Peak	*Load Factor*	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	*1,636*	*0.79*	2002
2003			9,846,294	1,232,635	11,078,929	*1,671*	*0.76*	2003
2004			10,324,412	1,267,728	11,592,140	*1,721*	*0.77*	2004
2005			10,531,272	1,258,895	11,790,167	*1,727*	*0.78*	2005
2006			10,649,101	1,195,070	11,844,171	*1,753*	*0.77*	2006
2007			10,680,514	1,252,965	11,933,479	*1,763*	*0.77*	2007
2008			10,839,446	1,276,158	12,115,604	*1,719*	*0.80*	2008
2009			8,065,088	1,108,014	9,173,102	*1,545*	*0.68*	2009
2010			10,417,414	1,299,292	11,716,706	*1,789*	*0.75*	2010
2011			10,988,200	1,422,107	12,410,307	*1,779*	*0.80*	2011
2012			11,107,357	1,200,317	12,307,674	*1,790*	*0.78*	2012
2013	10,985,809		10,985,809	1,185,139	12,170,948	*1,782*	*0.78*	2013
2014	10,801,397	197,504	**10,998,901**	1,251,630	**12,250,531**	***1,758***	***0.80***	2014
2015	10,811,606	475,705	**11,287,311**	1,251,630	**12,538,941**	***1,862***	***0.77***	**2015**
2016	10,903,391	866,765	**11,770,156**	1,284,222	**13,054,378**	***1,874***	***0.79***	2016
2017	10,920,224	857,858	**11,778,082**	1,324,338	**13,102,420**	***1,879***	***0.80***	2017
2018	10,933,261	856,396	**11,789,657**	1,324,338	**13,113,995**	***1,884***	***0.79***	2018
2019	10,980,794	856,396	**11,837,190**	1,324,338	**13,161,528**	***1,893***	***0.79***	2019
2020	11,066,720	858,742	**11,925,462**	1,327,967	**13,253,429**	***1,901***	***0.79***	**2020**
2021	11,080,537	856,396	**11,936,933**	1,324,338	**13,261,271**	***1,908***	***0.79***	2021
2022	11,124,600	856,396	**11,980,996**	1,324,338	**13,305,334**	***1,914***	***0.79***	2022
2023	11,178,582	856,396	**12,034,978**	1,324,338	**13,359,316**	***1,924***	***0.79***	2023
2024	11,256,408	858,742	**12,115,150**	1,327,967	**13,443,117**	***1,932***	***0.79***	2024
2025	11,281,839	856,396	**12,138,235**	1,324,338	**13,462,573**	***1,940***	***0.79***	**2025**
2026	11,339,586	856,396	**12,195,982**	1,324,338	**13,520,321**	***1,948***	***0.79***	2026
2027	11,399,398	856,396	**12,255,794**	1,324,338	**13,580,133**	***1,958***	***0.79***	2027
2028	11,491,551	858,742	**12,350,294**	1,327,967	**13,678,260**	***1,967***	***0.79***	2028

iv. Potential Upside Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,584	1,534	169	170	1,753	1,704	1,753	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,526	1,554	35	46	1,561	1,600	172	178	1,732	1,778	1,778	2014
2015	1,543	1,563	94	191	1,637	1,754	177	196	1,814	1,950	1,950	**2015**
2016	1,551	1,573	186	200	1,737	1,773	195	202	1,932	1,975	1,975	2016
2017	1,557	1,578	207	240	1,765	1,818	201	202	1,965	2,020	2,020	2017
2018	1,560	1,584	295	298	1,855	1,882	201	202	2,056	2,084	2,084	2018
2019	1,568	1,593	298	314	1,865	1,907	201	202	2,066	2,109	2,109	2019
2020	1,576	1,601	314	318	1,890	1,918	201	202	2,091	2,120	2,120	**2020**
2021	1,582	1,608	318	318	1,899	1,925	201	202	2,100	2,127	2,127	2021
2022	1,588	1,615	318	318	1,906	1,932	201	202	2,107	2,134	2,134	2022
2023	1,595	1,624	318	318	1,913	1,942	201	202	2,114	2,144	2,144	2023
2024	1,603	1,633	318	318	1,920	1,950	201	202	2,121	2,152	2,152	2024
2025	1,610	1,640	318	318	1,927	1,958	201	202	2,128	2,160	2,160	**2025**
2026	1,617	1,649	318	318	1,935	1,966	201	202	2,136	2,168	2,168	2026
2027	1,625	1,658	318	318	1,943	1,976	201	202	2,143	2,178	2,178	2027
2028	1,633	1,668	318	318	1,950	1,985	201	202	2,151	2,187	2,187	2028

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	Load Factor	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	1,636	0.79	2002
2003			9,846,294	1,232,635	11,078,929	1,671	0.76	2003
2004			10,324,412	1,267,728	11,592,140	1,721	0.77	2004
2005			10,531,272	1,258,895	11,790,167	1,727	0.78	2005
2006			10,649,101	1,195,070	11,844,171	1,753	0.77	2006
2007			10,680,514	1,252,965	11,933,479	1,763	0.77	2007
2008			10,839,446	1,276,158	12,115,604	1,719	0.80	2008
2009			8,065,088	1,108,014	9,173,102	1,545	0.68	2009
2010			10,417,414	1,299,292	11,716,706	1,789	0.75	2010
2011			10,988,200	1,422,107	12,410,307	1,779	0.80	2011
2012			11,107,357	1,200,317	12,307,674	1,790	0.78	2012
2013	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,808,736	197,504	11,006,240	1,251,630	12,257,870	1,778	0.79	2014
2015	10,819,363	635,938	11,455,301	1,286,450	12,741,751	1,950	0.75	**2015**
2016	10,907,299	1,349,278	12,256,577	1,422,746	13,679,323	1,975	0.79	2016
2017	10,927,293	1,347,118	12,274,411	1,462,483	13,736,895	2,020	0.78	2017
2018	10,941,302	1,863,436	12,804,739	1,462,483	14,267,222	2,084	0.78	2018
2019	10,990,052	2,049,739	13,039,792	1,462,483	14,502,275	2,109	0.79	2019
2020	11,076,125	2,144,396	13,220,521	1,466,490	14,687,011	2,120	0.79	**2020**
2021	11,091,367	2,165,517	13,256,885	1,462,483	14,719,368	2,127	0.79	2021
2022	11,136,481	2,165,517	13,301,998	1,462,483	14,764,481	2,134	0.79	2022
2023	11,191,079	2,165,517	13,356,596	1,462,483	14,819,080	2,144	0.79	2023
2024	11,269,910	2,171,450	13,441,360	1,466,490	14,907,850	2,152	0.79	2024
2025	11,296,276	2,165,517	13,461,794	1,462,483	14,924,277	2,160	0.79	**2025**
2026	11,355,051	2,165,517	13,520,568	1,462,483	14,983,052	2,168	0.79	2026
2027	11,415,048	2,165,517	13,580,565	1,462,483	15,043,048	2,178	0.79	2027
2028	11,508,208	2,171,450	13,679,658	1,466,490	15,146,148	2,187	0.79	2028

V. Potential Downside Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,584	1,534	169	170	1,753	1,704	1,753	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,523	1,547	30	12	1,553	1,559	172	173	1,725	1,732	1,732	2014
2015	1,537	1,557	30	20	1,567	1,577	172	180	1,738	1,758	1,758	**2015**
2016	1,542	1,565	1	(16)	1,543	1,549	179	190	1,722	1,739	1,739	2016
2017	1,548	1,522	4	53	1,552	1,575	189	190	1,741	1,765	1,765	2017
2018	1,549	1,572	(21)	(18)	1,528	1,554	189	190	1,717	1,744	1,744	2018
2019	1,555	1,580	(18)	(24)	1,537	1,556	189	190	1,726	1,746	1,746	2019
2020	1,563	1,518	(24)	0	1,539	1,518	189	190	1,728	1,708	1,728	**2020**
2021	1,568	1,593	(96)	(96)	1,472	1,497	189	190	1,661	1,687	1,687	2021
2022	1,574	1,599	(96)	(96)	1,478	1,503	189	190	1,667	1,693	1,693	2022
2023	1,580	1,608	(96)	(96)	1,484	1,512	189	190	1,673	1,702	1,702	2023
2024	1,587	1,616	(96)	(96)	1,491	1,520	189	190	1,680	1,710	1,710	2024
2025	1,593	1,623	(96)	(96)	1,497	1,527	189	190	1,686	1,716	1,716	**2025**
2026	1,600	1,630	(96)	(96)	1,504	1,534	189	190	1,693	1,724	1,724	2026
2027	1,606	1,639	(96)	(96)	1,510	1,543	189	190	1,699	1,732	1,732	2027
2028	1,613	1,647	(96)	(96)	1,517	1,551	189	190	1,706	1,740	1,740	2028

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	Load Factor	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	1,636	0.79	2002
2003			9,846,294	1,232,635	11,078,929	1,671	0.76	2003
2004			10,324,412	1,267,728	11,592,140	1,721	0.77	2004
2005			10,531,272	1,258,895	11,790,167	1,727	0.78	2005
2006			10,649,101	1,195,070	11,844,171	1,753	0.77	2006
2007			10,680,514	1,252,965	11,933,479	1,763	0.77	2007
2008			10,839,446	1,276,158	12,115,604	1,719	0.80	2008
2009			8,065,088	1,108,014	9,173,102	1,545	0.68	2009
2010			10,417,414	1,299,292	11,716,706	1,789	0.75	2010
2011			10,988,200	1,422,107	12,410,307	1,779	0.80	2011
2012			11,107,357	1,200,317	12,307,674	1,790	0.78	2012
2013	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,778,208	197,504	10,975,711	1,251,630	12,227,342	1,732	0.81	2014
2015	10,755,916	141,986	10,897,901	1,251,630	12,149,532	1,758	0.79	**2015**
2016	10,831,267	44,216	10,875,483	1,309,740	12,185,223	1,739	0.80	2016
2017	10,834,412	(159,504)	10,674,908	1,375,234	12,050,142	1,765	0.78	2017
2018	10,833,747	(456,854)	10,376,893	1,375,234	11,752,127	1,744	0.77	2018
2019	10,864,734	(433,876)	10,430,858	1,375,234	11,806,092	1,746	0.77	2019
2020	10,945,162	(481,005)	10,464,157	1,379,002	11,843,159	1,728	0.78	**2020**
2021	10,956,536	(1,015,802)	9,940,734	1,375,234	11,315,968	1,687	0.77	2021
2022	10,993,567	(1,015,802)	9,977,765	1,375,234	11,352,999	1,693	0.77	2022
2023	11,039,557	(1,015,802)	10,023,755	1,375,234	11,398,989	1,702	0.76	2023
2024	11,109,422	(1,018,585)	10,090,836	1,379,002	11,469,838	1,710	0.76	2024
2025	11,128,256	(1,015,802)	10,112,454	1,375,234	11,487,688	1,716	0.76	**2025**
2026	11,176,543	(1,015,802)	10,160,741	1,375,234	11,535,975	1,724	0.76	2026
2027	11,227,623	(1,015,802)	10,211,820	1,375,234	11,587,054	1,732	0.76	2027
2028	11,310,018	(1,018,585)	10,291,433	1,379,002	11,670,434	1,740	0.76	2028

vi. **Best Case Scenario**

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,584	1,534	169	170	1,753	1,704	1,753	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,526	1,561	35	46	**1,561**	**1,607**	172	178	**1,733**	**1,784**	***1,784***	2014
2015	1,548	1,569	94	197	**1,642**	**1,765**	177	192	**1,819**	**1,957**	***1,957***	**2015**
2016	1,557	1,580	196	254	**1,753**	**1,834**	191	192	**1,944**	**2,026**	***2,026***	2016
2017	1,565	1,586	261	299	**1,826**	**1,885**	191	145	**2,017**	**2,030**	***2,030***	2017
2018	1,569	1,593	437	449	**2,005**	**2,042**	144	112	**2,149**	**2,154**	***2,154***	2018
2019	1,577	1,604	457	523	**2,034**	**2,126**	111	112	**2,145**	**2,238**	***2,238***	2019
2020	1,587	1,613	563	691	**2,151**	**2,304**	111	112	**2,261**	**2,416**	***2,416***	**2020**
2021	1,594	1,621	691	691	**2,285**	**2,312**	111	112	**2,396**	**2,424**	***2,424***	2021
2022	1,601	1,629	691	691	**2,292**	**2,320**	111	112	**2,403**	**2,432**	***2,432***	2022
2023	1,610	1,639	691	691	**2,301**	**2,330**	111	112	**2,411**	**2,442**	***2,442***	2023
2024	1,618	1,649	691	691	**2,309**	**2,340**	111	112	**2,420**	**2,452**	***2,452***	2024
2025	1,626	1,658	691	691	**2,317**	**2,349**	111	112	**2,427**	**2,461**	***2,461***	**2025**
2026	1,634	1,667	691	691	**2,325**	**2,358**	111	112	**2,436**	**2,470**	***2,470***	2026
2027	1,643	1,678	691	691	**2,334**	**2,369**	111	112	**2,445**	**2,481**	***2,481***	2027
2028	1,652	1,689	691	691	**2,343**	**2,380**	111	112	**2,454**	**2,492**	***2,492***	2028

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	*Load Factor*	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	*1,636*	*0.79*	2002
2003			9,846,294	1,232,635	11,078,929	*1,671*	*0.76*	2003
2004			10,324,412	1,267,728	11,592,140	*1,721*	*0.77*	2004
2005			10,531,272	1,258,895	11,790,167	*1,727*	*0.78*	2005
2006			10,649,101	1,195,070	11,844,171	*1,753*	*0.77*	2006
2007			10,680,514	1,252,965	11,933,479	*1,763*	*0.77*	2007
2008			10,839,446	1,276,158	12,115,604	*1,719*	*0.80*	2008
2009			8,065,088	1,108,014	9,173,102	*1,545*	*0.68*	2009
2010			10,417,414	1,299,292	11,716,706	*1,789*	*0.75*	2010
2011			10,988,200	1,422,107	12,410,307	*1,779*	*0.80*	2011
2012			11,107,357	1,200,317	12,307,674	*1,790*	*0.78*	2012
2013	10,985,809		10,985,809	1,185,139	12,170,948	*1,782*	*0.78*	2013
2014	10,824,555	197,504	**11,022,058**	1,251,630	**12,273,689**	***1,784***	***0.79***	2014
2015	10,870,986	635,938	**11,506,924**	1,286,450	**12,793,375**	***1,957***	***0.75***	**2015**
2016	10,969,237	1,408,435	**12,377,671**	1,393,583	**13,771,255**	***2,026***	***0.77***	2016
2017	10,999,225	1,756,413	**12,755,638**	1,389,775	**14,145,414**	***2,030***	***0.80***	2017
2018	11,024,117	2,704,174	**13,728,291**	1,048,745	**14,777,036**	***2,154***	***0.78***	2018
2019	11,088,560	3,299,983	**14,388,543**	808,111	**15,196,654**	***2,238***	***0.78***	2019
2020	11,188,824	4,122,093	**15,310,918**	810,325	**16,121,243**	***2,416***	***0.76***	**2020**
2021	11,214,503	4,973,422	**16,187,925**	808,111	**16,996,037**	***2,424***	***0.80***	2021
2022	11,270,404	4,973,422	**16,243,826**	808,111	**17,051,938**	***2,432***	***0.80***	2022
2023	11,333,762	4,973,422	**16,307,184**	808,111	**17,115,295**	***2,442***	***0.80***	2023
2024	11,423,702	4,987,048	**16,410,750**	810,325	**17,221,075**	***2,452***	***0.80***	2024
2025	11,459,373	4,973,422	**16,432,795**	808,111	**17,240,906**	***2,461***	***0.80***	**2025**
2026	11,527,964	4,973,422	**16,501,386**	808,111	**17,309,498**	***2,470***	***0.80***	2026
2027	11,599,361	4,973,422	**16,572,783**	808,111	**17,380,895**	***2,481***	***0.80***	2027
2028	11,704,344	4,987,048	**16,691,392**	810,325	**17,501,717**	***2,492***	***0.80***	2028

Sensitivities

Minnesota Power conducts tests to identify the sensitivity of the forecast to changes in weather and large customer operation. The forecast sensitivities were developed for customer counts, energy sales, and seasonal peak demand models to demonstrate a range of outcomes resulting from these changes.

The following Base Case sensitivities and alternative forecast methods have been conducted on the AFR 2014 forecasts:

- Trended Weather – Historical trend in weather is assumed instead of a 20 year average
- Extreme Weather – Historical extremes are assumed instead of a 20 year average
- Plug-in Electric Vehicle – Applies an estimate of the impact of PEV on the Minnesota Power system
- Customer Contract Expiration – Assumes several of Minnesota Power's largest customers do not renew their current contracts with Minnesota Power.

Trended Weather

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	*Annual*	
2000					1,469	1,503	242	281	1,711	1,784	*1,784*	2000
2001					1,383	1,421	150	175	1,533	1,595	*1,595*	2001
2002					1,464	1,456	165	180	1,629	1,636	*1,636*	2002
2003					1,408	1,496	163	175	1,570	1,671	*1,671*	2003
2004					1,449	1,533	168	189	1,617	1,721	*1,721*	2004
2005					1,535	1,555	169	172	1,703	1,727	*1,727*	2005
2006					1,584	1,534	169	170	1,753	1,704	*1,753*	2006
2007					1,582	1,584	176	179	1,758	1,763	*1,763*	2007
2008					1,552	1,575	147	145	1,699	1,719	*1,719*	2008
2009					1,200	1,369	150	176	1,350	1,545	*1,545*	2009
2010					1,591	1,599	140	190	1,732	1,789	*1,789*	2010
2011					1,573	1,629	173	150	1,746	1,779	*1,779*	2011
2012					1,603	1,605	187	169	1,790	1,774	*1,790*	2012
2013					1,645	1,589	136	162	1,782	1,751	*1,782*	2013
2014	1,527	1,552	30	45	**1,557**	**1,596**	172	173	**1,729**	**1,769**	***1,769***	2014
2015	1,544	1,562	93	176	**1,637**	**1,738**	172	192	**1,809**	**1,929**	***1,929***	**2015**
2016	1,552	1,573	171	183	**1,723**	**1,756**	201	202	**1,924**	**1,958**	***1,958***	2016
2017	1,559	1,580	183	193	**1,741**	**1,772**	201	202	**1,942**	**1,974**	***1,974***	2017
2018	1,562	1,586	193	194	**1,754**	**1,780**	201	202	**1,955**	**1,982**	***1,982***	2018
2019	1,569	1,597	194	194	**1,763**	**1,790**	201	202	**1,963**	**1,992**	***1,992***	2019
2020	1,578	1,599	194	194	**1,771**	**1,793**	201	202	**1,972**	**1,995**	***1,995***	**2020**
2021	1,584	1,608	194	194	**1,777**	**1,801**	201	202	**1,978**	**2,003**	***2,003***	2021
2022	1,590	1,616	194	194	**1,784**	**1,809**	201	202	**1,985**	**2,011**	***2,011***	2022
2023	1,598	1,626	194	194	**1,791**	**1,820**	201	202	**1,992**	**2,021**	***2,021***	2023
2024	1,605	1,636	194	194	**1,798**	**1,829**	201	202	**1,999**	**2,031**	***2,031***	2024
2025	1,612	1,645	194	194	**1,806**	**1,838**	201	202	**2,006**	**2,040**	***2,040***	**2025**
2026	1,694	1,654	194	194	**1,887**	**1,847**	201	202	**2,088**	**2,049**	***2,088***	2026
2027	1,703	1,665	194	194	**1,896**	**1,858**	201	202	**2,097**	**2,060**	***2,097***	2027
2028	1,711	1,675	194	194	**1,904**	**1,868**	201	202	**2,105**	**2,070**	***2,105***	2028

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	*Load Factor*	
2000			10,243,434					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	*1,636*	*0.79*	2002
2003			9,846,294	1,232,635	11,078,929	*1,671*	*0.76*	2003
2004			10,324,412	1,267,728	11,592,140	*1,721*	*0.77*	2004
2005			10,531,271	1,258,895	11,790,166	*1,727*	*0.78*	2005
2006			10,649,101	1,195,070	11,844,171	*1,753*	*0.77*	2006
2007			10,680,509	1,252,965	11,933,474	*1,763*	*0.77*	2007
2008			10,839,446	1,276,158	12,115,604	*1,719*	*0.80*	2008
2009			8,065,090	1,108,014	9,173,104	*1,545*	*0.68*	2009
2010			10,417,422	1,299,292	11,716,714	*1,789*	*0.75*	2010
2011			10,988,200	1,422,107	12,410,307	*1,779*	*0.80*	2011
2012			11,107,358	1,200,317	12,307,675	*1,790*	*0.78*	2012
2013	10,985,809		10,985,809	1,185,139	12,170,948	*1,782*	*0.78*	2013
2014	10,815,714	197,504	**11,013,218**	1,251,630	**12,264,848**	***1,769***	***0.79***	2014
2015	10,829,543	635,938	**11,465,481**	1,286,450	**12,751,931**	***1,929***	***0.75***	**2015**
2016	10,919,740	1,304,421	**12,224,161**	1,422,746	**13,646,907**	***1,958***	***0.79***	2016
2017	10,937,846	1,213,426	**12,151,273**	1,462,483	**13,613,756**	***1,974***	***0.79***	2017
2018	10,952,084	1,286,636	**12,238,720**	1,462,483	**13,701,204**	***1,982***	***0.79***	2018
2019	11,001,346	1,294,783	**12,296,129**	1,462,483	**13,758,612**	***1,992***	***0.79***	2019
2020	11,092,148	1,298,331	**12,390,478**	1,466,490	**13,856,969**	***1,995***	***0.79***	**2020**
2021	11,104,555	1,294,783	**12,399,338**	1,462,483	**13,861,822**	***2,003***	***0.79***	2021
2022	11,150,747	1,294,783	**12,445,530**	1,462,483	**13,908,013**	***2,011***	***0.79***	2022
2023	11,206,047	1,294,783	**12,500,831**	1,462,483	**13,963,314**	***2,021***	***0.79***	2023
2024	11,288,558	1,298,331	**12,586,889**	1,466,490	**14,053,379**	***2,031***	***0.79***	2024
2025	11,312,714	1,294,783	**12,607,497**	1,462,483	**14,069,981**	***2,040***	***0.79***	**2025**
2026	11,371,798	1,294,783	**12,666,581**	1,462,483	**14,129,064**	***2,088***	***0.77***	2026
2027	11,432,958	1,294,783	**12,727,741**	1,462,483	**14,190,225**	***2,097***	***0.77***	2027
2028	11,529,630	1,298,331	**12,827,961**	1,466,490	**14,294,451**	***2,105***	***0.77***	2028

Extreme Weather

Peak Forecast (MW)

	Econometric		+	Net Load Added		=	MP Delivered Load		+	Customer Gen.		=	MP System Peak			
	Sum	Win		Sum	Win		**Sum**	**Win**		Sum	Win		**Sum**	**Win**	*Annual*	
2000							1,469	1,503		242	281		1,711	1,784	*1,784*	2000
2001							1,383	1,421		150	175		1,533	1,595	*1,595*	2001
2002							1,464	1,456		165	180		1,629	1,636	*1,636*	2002
2003							1,408	1,496		163	175		1,570	1,671	*1,671*	2003
2004							1,449	1,533		168	189		1,617	1,721	*1,721*	2004
2005							1,535	1,555		169	172		1,703	1,727	*1,727*	2005
2006							1,584	1,534		169	170		1,753	1,704	*1,753*	2006
2007							1,582	1,584		176	179		1,758	1,763	*1,763*	2007
2008							1,552	1,575		147	145		1,699	1,719	*1,719*	2008
2009							1,200	1,369		150	176		1,350	1,545	*1,545*	2009
2010							1,591	1,599		140	190		1,732	1,789	*1,789*	2010
2011							1,573	1,629		173	150		1,746	1,779	*1,779*	2011
2012							1,603	1,605		187	169		1,790	1,774	*1,790*	2012
2013							1,645	1,589		136	162		1,782	1,751	*1,782*	2013
2014	1,603	1,573		30	50		**1,633**	**1,622**		172	170		**1,805**	**1,792**	***1,805***	2014
2015	1,621	1,578		93	176		**1,713**	**1,753**		172	189		**1,885**	**1,943**	***1,943***	**2015**
2016	1,628	1,590		171	185		**1,800**	**1,776**		201	202		**2,000**	**1,978**	***2,000***	2016
2017	1,635	1,594		183	193		**1,818**	**1,786**		201	199		**2,018**	**1,985**	***2,018***	2017
2018	1,638	1,598		193	194		**1,830**	**1,792**		201	199		**2,031**	**1,991**	***2,031***	2018
2019	1,645	1,603		194	194		**1,839**	**1,796**		201	201		**2,039**	**1,997**	***2,039***	2019
2020	1,653	1,612		194	194		**1,847**	**1,806**		201	199		**2,048**	**2,005**	***2,048***	**2020**
2021	1,660	1,618		194	194		**1,853**	**1,811**		201	201		**2,054**	**2,012**	***2,054***	2021
2022	1,666	1,623		194	194		**1,859**	**1,817**		201	202		**2,060**	**2,019**	***2,060***	2022
2023	1,673	1,633		194	194		**1,866**	**1,826**		201	202		**2,067**	**2,028**	***2,067***	2023
2024	1,680	1,642		194	194		**1,874**	**1,835**		201	202		**2,074**	**2,037**	***2,074***	2024
2025	1,687	1,649		194	194		**1,881**	**1,843**		201	202		**2,082**	**2,044**	***2,082***	**2025**
2026	1,695	1,657		194	194		**1,888**	**1,851**		201	202		**2,089**	**2,053**	***2,089***	2026
2027	1,702	1,667		194	194		**1,896**	**1,861**		201	202		**2,097**	**2,062**	***2,097***	2027
2028	1,710	1,676		194	194		**1,904**	**1,870**		201	202		**2,104**	**2,072**	***2,104***	2028

Energy Sales Forecast (MWh)

	Econometric	+	Net Energy Added	=	MP Delivered Energy	+	Customer Gen.	=	System Energy Use	MP System		
										Peak	*Load Factor*	
2000					10,243,434							
2001					9,658,073							
2002					10,160,143		1,187,858		11,348,001	*1,636*	*0.79*	2002
2003					9,846,294		1,232,635		11,078,929	*1,671*	*0.76*	2003
2004					10,324,412		1,267,728		11,592,140	*1,721*	*0.77*	2004
2005					10,531,271		1,258,895		11,790,166	*1,727*	*0.78*	2005
2006					10,649,101		1,195,070		11,844,171	*1,753*	*0.77*	2006
2007					10,680,509		1,252,965		11,933,474	*1,763*	*0.77*	2007
2008					10,839,446		1,276,158		12,115,604	*1,719*	*0.80*	2008
2009					8,065,090		1,108,014		9,173,104	*1,545*	*0.68*	2009
2010					10,417,422		1,299,292		11,716,714	*1,789*	*0.75*	2010
2011					10,988,200		1,422,107		12,410,307	*1,779*	*0.80*	2011
2012					11,107,358		1,200,317		12,307,675	*1,790*	*0.78*	2012
2013	10,985,809				10,985,809		1,185,139		12,170,948	*1,782*	*0.78*	2013
2014	10,915,663		197,504		**11,113,166**		1,251,630		**12,364,796**	***1,805***	***0.78***	2014
2015	10,962,708		635,938		**11,598,646**		1,286,450		**12,885,096**	***1,943***	***0.76***	**2015**
2016	11,052,881		1,304,421		**12,357,302**		1,422,746		**13,780,048**	***2,000***	***0.78***	2016
2017	11,070,948		1,213,426		**12,284,374**		1,462,483		**13,746,858**	***2,018***	***0.78***	2017
2018	11,085,691		1,286,636		**12,372,328**		1,462,483		**13,834,811**	***2,031***	***0.78***	2018
2019	11,135,205		1,294,783		**12,429,988**		1,462,483		**13,892,471**	***2,039***	***0.78***	2019
2020	11,226,590		1,298,331		**12,524,921**		1,466,490		**13,991,411**	***2,048***	***0.78***	**2020**
2021	11,238,716		1,294,783		**12,533,499**		1,462,483		**13,995,982**	***2,054***	***0.78***	2021
2022	11,285,063		1,294,783		**12,579,846**		1,462,483		**14,042,329**	***2,060***	***0.78***	2022
2023	11,340,518		1,294,783		**12,635,301**		1,462,483		**14,097,785**	***2,067***	***0.78***	2023
2024	11,423,461		1,298,331		**12,721,791**		1,466,490		**14,188,281**	***2,074***	***0.78***	2024
2025	11,447,195		1,294,783		**12,741,978**		1,462,483		**14,204,461**	***2,082***	***0.78***	**2025**
2026	11,506,214		1,294,783		**12,800,997**		1,462,483		**14,263,481**	***2,089***	***0.78***	2026
2027	11,567,339		1,294,783		**12,862,122**		1,462,483		**14,324,605**	***2,097***	***0.78***	2027
2028	11,664,453		1,298,331		**12,962,783**		1,466,490		**14,429,274**	***2,104***	***0.78***	2028

Plug-in Electric Vehicle

Peak Forecast (MW)

	Econometric		+ PEV Load Added		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000							1,469	1,503	242	281	1,711	1,784	1,784	2000
2001							1,383	1,421	150	175	1,533	1,595	1,595	2001
2002							1,464	1,456	165	180	1,629	1,636	1,636	2002
2003							1,408	1,496	163	175	1,570	1,671	1,671	2003
2004							1,449	1,533	168	189	1,617	1,721	1,721	2004
2005							1,535	1,555	169	172	1,703	1,727	1,727	2005
2006							1,584	1,534	169	170	1,753	1,704	1,754	2006
2007							1,582	1,584	176	179	1,758	1,763	1,763	2007
2008							1,552	1,575	147	145	1,699	1,719	1,719	2008
2009							1,200	1,369	150	176	1,350	1,545	1,545	2009
2010							1,591	1,599	140	190	1,732	1,789	1,789	2010
2011							1,573	1,629	173	150	1,746	1,779	1,779	2011
2012							1,603	1,605	187	169	1,790	1,774	1,790	2012
2013							1,645	1,589	136	162	1,782	1,751	1,750	2013
2014	1,526	1,554	0.0	0.1	35	50	1,561	1,604	172	173	1,732	1,777	1,777	2014
2015	1,543	1,563	0.0	0.1	98	181	1,641	1,744	172	192	1,812	1,936	1,936	**2015**
2016	1,551	1,573	0.1	0.2	176	188	1,727	1,761	201	202	1,928	1,963	1,963	2016
2017	1,557	1,578	0.1	0.3	188	198	1,745	1,776	201	202	1,946	1,978	1,978	2017
2018	1,560	1,584	0.1	0.4	198	199	1,758	1,783	201	202	1,959	1,985	1,985	2018
2019	1,567	1,593	0.1	0.5	199	199	1,766	1,792	201	202	1,967	1,994	1,994	2019
2020	1,576	1,601	0.2	0.6	199	199	1,774	1,800	201	202	1,975	2,002	2,002	**2020**
2021	1,582	1,608	0.2	0.8	199	199	1,780	1,807	201	202	1,981	2,009	2,009	2021
2022	1,588	1,614	0.3	0.9	199	199	1,787	1,814	201	202	1,988	2,016	2,016	2022
2023	1,595	1,624	0.3	1.2	199	199	1,794	1,823	201	202	1,995	2,025	2,025	2023
2024	1,602	1,632	0.4	1.4	199	199	1,801	1,832	201	202	2,002	2,034	2,034	2024
2025	1,609	1,640	0.4	1.7	199	199	1,808	1,840	201	202	2,009	2,042	2,042	**2025**
2026	1,617	1,648	0.5	2.0	199	199	1,816	1,849	201	202	2,017	2,051	2,051	2026
2027	1,625	1,658	0.6	2.3	199	199	1,824	1,859	201	202	2,025	2,061	2,061	2027
2028	1,632	1,667	0.7	2.7	199	199	1,831	1,868	201	202	2,032	2,070	2,070	2028

Energy Sales Forecast (MWh)

	Econometric	+ PEV Energy Added	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
							Peak	Load Factor	
2000				10,245,420					
2001				9,658,073					
2002				10,160,143	1,187,858	11,348,001	1,636	0.79	2002
2003				9,846,294	1,232,635	11,078,929	1,671	0.76	2003
2004				10,324,412	1,267,728	11,592,140	1,721	0.77	2004
2005				10,531,272	1,258,895	11,790,167	1,727	0.78	2005
2006				10,649,101	1,195,070	11,844,171	1,754	0.77	2006
2007				10,680,514	1,252,965	11,933,479	1,763	0.77	2007
2008				10,839,446	1,276,158	12,115,604	1,719	0.80	2008
2009				8,065,088	1,108,014	9,173,102	1,545	0.68	2009
2010				10,417,414	1,299,292	11,716,706	1,789	0.75	2010
2011				10,988,200	1,422,107	12,410,307	1,779	0.80	2011
2012				11,107,357	1,200,317	12,307,674	1,790	0.78	2012
2013				10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,808,480	1,082	197,504	11,007,066	1,251,630	12,258,696	1,777	0.79	2014
2015	10,819,622	1,724	635,938	11,457,284	1,286,450	12,743,734	1,936	0.75	**2015**
2016	10,906,285	2,602	1,304,421	12,213,309	1,422,746	13,636,054	1,963	0.79	2016
2017	10,926,100	3,773	1,213,426	12,143,300	1,462,483	13,605,783	1,978	0.79	2017
2018	10,939,368	4,921	1,286,636	12,230,925	1,462,483	13,693,409	1,985	0.79	2018
2019	10,987,659	6,361	1,294,783	12,288,803	1,462,483	13,751,286	1,994	0.79	2019
2020	11,074,743	8,123	1,298,331	12,381,196	1,466,490	13,847,687	2,002	0.79	**2020**
2021	11,088,873	10,232	1,294,783	12,393,888	1,462,483	13,856,372	2,009	0.79	2021
2022	11,134,063	12,711	1,294,783	12,441,558	1,462,483	13,904,041	2,016	0.79	2022
2023	11,188,371	15,576	1,294,783	12,498,729	1,462,483	13,961,213	2,025	0.79	2023
2024	11,267,085	18,843	1,298,331	12,584,259	1,466,490	14,050,749	2,034	0.79	2024
2025	11,293,034	22,528	1,294,783	12,610,345	1,462,483	14,072,829	2,042	0.79	**2025**
2026	11,351,103	26,640	1,294,783	12,672,527	1,462,483	14,135,010	2,051	0.79	2026
2027	11,411,239	31,187	1,294,783	12,737,209	1,462,483	14,199,692	2,061	0.79	2027
2028	11,503,999	35,726	1,298,331	12,838,056	1,466,490	14,304,547	2,070	0.79	2028

Customer Contract Expiration

Peak Forecast (MW)

	Current Contract		+ Contract Lost		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,584	1,534	169	170	1,753	1,704	1,753	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,526	1,554	0	0	1,526	1,554	172	173	1,697	1,727	1,727	2014
2015	1,543	1,563	(17)	(17)	1,526	1,546	172	177	1,698	1,723	1,723	**2015**
2016	1,551	1,573	(54)	(54)	1,497	1,519	176	183	1,673	1,702	1,702	2016
2017	1,557	1,578	(59)	(82)	1,498	1,496	182	183	1,680	1,679	1,680	2017
2018	1,560	1,584	(703)	(712)	857	872	182	183	1,039	1,055	1,055	2018
2019	1,567	1,593	(712)	(719)	855	874	182	183	1,037	1,057	1,057	2019
2020	1,576	1,601	(719)	(719)	857	882	182	183	1,039	1,064	1,064	**2020**
2021	1,582	1,608	(719)	(719)	863	889	182	183	1,045	1,071	1,071	2021
2022	1,588	1,614	(719)	(774)	869	840	182	183	1,051	1,023	1,051	2022
2023	1,595	1,624	(774)	(774)	821	850	182	183	1,003	1,033	1,033	2023
2024	1,602	1,632	(774)	(774)	828	858	182	183	1,010	1,041	1,041	2024
2025	1,609	1,640	(774)	(774)	835	866	182	183	1,017	1,049	1,049	**2025**
2026	1,617	1,648	(774)	(774)	843	874	182	183	1,024	1,057	1,057	2026
2027	1,625	1,658	(774)	(774)	850	884	182	183	1,032	1,067	1,067	2027
2028	1,632	1,667	(774)	(774)	858	893	182	183	1,040	1,076	1,076	2028

Energy Sales Forecast (MWh)

	Moderate Growth	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	Load Factor	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	1,636	0.79	2002
2003			9,846,294	1,232,635	11,078,929	1,671	0.76	2003
2004			10,324,412	1,267,728	11,592,140	1,721	0.77	2004
2005			10,531,272	1,258,895	11,790,167	1,727	0.78	2005
2006			10,649,101	1,195,070	11,844,171	1,753	0.77	2006
2007			10,680,514	1,252,965	11,933,479	1,763	0.77	2007
2008			10,839,446	1,276,158	12,115,604	1,719	0.80	2008
2009			8,065,088	1,108,014	9,173,102	1,545	0.68	2009
2010			10,417,414	1,299,292	11,716,706	1,789	0.75	2010
2011			10,988,200	1,422,107	12,410,307	1,779	0.80	2011
2012			11,107,357	1,200,317	12,307,674	1,790	0.78	2012
2013			10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	11,005,984	0	11,005,984	1,251,630	12,257,614	1,727	0.81	2014
2015	11,455,560	(69,066)	11,386,493	1,251,630	12,638,124	1,723	0.84	**2015**
2016	12,210,706	(287,702)	11,923,004	1,284,222	13,207,226	1,702	0.89	2016
2017	12,139,526	(455,510)	11,684,016	1,324,338	13,008,354	1,680	0.88	2017
2018	12,226,004	(3,183,804)	9,042,201	1,324,338	10,366,539	1,055	1.12	2018
2019	12,282,442	(5,738,150)	6,544,292	1,324,338	7,868,630	1,057	0.85	2019
2020	12,373,073	(5,810,440)	6,562,633	1,327,967	7,890,599	1,064	0.85	**2020**
2021	12,383,656	(5,794,565)	6,589,091	1,324,338	7,913,430	1,071	0.84	2021
2022	12,428,847	(5,794,565)	6,634,282	1,324,338	7,958,620	1,051	0.86	2022
2023	12,483,154	(6,237,821)	6,245,333	1,324,338	7,569,671	1,033	0.84	2023
2024	12,565,416	(6,256,130)	6,309,286	1,327,967	7,637,253	1,041	0.84	2024
2025	12,587,817	(6,240,239)	6,347,579	1,324,338	7,671,917	1,049	0.83	**2025**
2026	12,645,886	(6,240,239)	6,405,648	1,324,338	7,729,986	1,057	0.83	2026
2027	12,706,022	(6,240,239)	6,465,784	1,324,338	7,790,122	1,067	0.83	2027
2028	12,802,330	(6,257,335)	6,544,995	1,327,967	7,872,961	1,076	0.84	2028

3. Other Information

A. Subject of Assumption

Section 7610.0320, Subpart 4, lists specific assumptions to be discussed. The following list contains the discussion of each assumption and Minnesota Power's response.

- Assumptions made regarding the availability of alternative sources of energy.
    - Minnesota Power makes no assumptions regarding the availability of alternative sources of energy.
- Assumptions made regarding expected conversion from other fuels to electricity or vice versa.
    - Minnesota Power's assumptions regarding conversion are explicitly included in the saturation rates for electric heating.
- Assumptions made regarding future prices of electricity for customers and the effect that such prices would have on system demand.
    - See Section 1.C.
- Assumptions made in arriving at the data requested (historical reporting).
    - Minnesota Power makes no such assumptions.
- Assumptions made regarding the effect of existing energy conservations programs under Federal or State legislation on long-term electricity demand
    - See Demand Side Management above.
- Assumptions made regarding the projected effect of new conservations programs the utility deems likely to occur through Fed or State.
    - See Section 1.F.
- Assumptions made regarding current and future saturation levels of appliances and electric space heating.
    - See Section 1.F.

B. Coordination of Forecasts with Other Systems

Minnesota Power is a member of the Midwest Reliability Organization, the Midcontinent Independent System Operator, Edison Electric Institute (EEI), Upper Midwest Utility Forecasters (UMUF), and other trade associations. While each member of these groups independently determines its power requirements, periodic meetings are held to share information and discuss forecasting techniques and methodologies.

C. Compliance with 7610.0320 Forecast Documentation

Statute or Rule	***Requirement***	***Reference Section***
7610.0320, Subp. 1(A)	The overall methodological framework that is used.	Section 1.A
7610.0320, Subp. 1(B)	The specific analytical techniques that are used, their purpose, and the components of the forecast to which they have been applied.	Sections 1.D, 1.F
7610.0320, Subp. 1(C)	The manner in which these specific techniques are related in producing the forecast.	Section 1.D
7610.0320, Subp. 1(D)	The purpose of the technique, typical computations specifying variables and data, and the results of appropriate statistical tests.	Section 1.F
7610.0320, Subp. 1(E)	Forecast confidence levels or ranges of accuracy for annual peak demand and annual electrical consumption.	Section 1.F
7610.0320, Subp. 1(F)	A brief analysis of the methodology used, including its strengths and weaknesses, its suitability to the system, cost considerations, data requirements, past accuracy, and any other factors considered significant to the utility.	Sections 1.B, 1.F
7610.0320, Subp. 2(A)	A complete list of data sets used in making the forecast, including a brief description of each data set and an explanation of how each was obtained, or a citation to the source.	Sections 1.C
7610.0320, Subp. 2(B)	A clear identification of any adjustments made to the raw data to adapt them for use in forecasts, including the nature of the adjustment, the reason for the adjustment, and the magnitude of the adjustment.	Section 1.F
7610.0320, Subp. 3	Discussion of essential assumptions.	Sections 1.E, 1.F
7610.0320, Subp. 4	Subject of assumption.	Section 3
7610.0320, Subp. 5(A)	Description of the extent to which the utility coordinates its load forecasts with those of other systems.	Section 3
7610.0320, Subp. 5(B)	Description of the manner in which such forecasts are coordinated.	Section 3

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:

Steve Loomis
MN Department of Commerce
steve.loomis@state.mn.us
(651) 539-1690

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	68
REPORT YEAR	2013
RILS ID#	U10680

UTILITY DETAILS	
UTILITY NAME	Minnesota Power Co
STREET ADDRESS	30 W Superior St
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	218/722-5642 x3865
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

CONTACT INFORMATION	
CONTACT NAME	
CONTACT TITLE	
CONTACT STREET ADDRESS	
CITY	
STATE	
ZIP CODE	
TELEPHONE	
CONTACT E-MAIL	

COMMENTS

PREPARER INFORMATION	
PERSON PREPARING FORMS	
PREPARER'S TITLE	
DATE	

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	2013	No. of Cust.	2,397	118,917	21,915	9	394	592	287	144,511	144,511
		MWH	67,547	1,018,934	1,256,540	4,851,094	2,022,899	16,066	51,736	9,284,816	9,284,816
Present Year	2014	No. of Cust.	2,397	118,421	21,921	9	378	664	281	144,072	144,072
		MWH	67,547	1,058,986	1,284,024	4,888,265	2,041,484	16,346	54,172	9,410,825	9,410,825
1st Forecast Year	2015	No. of Cust.	2,397	120,668	22,376	10	370	726	290	146,837	146,837
		MWH	67,547	1,034,325	1,287,245	5,152,115	2,025,526	16,380	54,967	9,638,104	9,638,104
2nd Forecast Year	2016	No. of Cust.	2,397	121,846	22,644	11	367	789	293	148,348	148,348
		MWH	67,547	1,049,601	1,310,008	5,343,277	1,899,090	16,654	56,293	9,742,469	9,742,469
3rd Forecast Year	2017	No. of Cust.	2,397	122,805	22,928	11	371	854	297	149,664	149,664
		MWH	67,547	1,056,768	1,326,212	5,259,033	1,866,742	16,738	56,630	9,649,670	9,649,670
4th Forecast Year	2018	No. of Cust.	2,397	123,600	23,205	11	373	910	300	150,796	150,796
		MWH	67,547	1,068,386	1,343,242	5,269,835	1,907,452	16,755	56,906	9,730,122	9,730,122
5th Forecast Year	2019	No. of Cust.	2,397	124,145	23,469	11	374	964	302	151,663	151,663
		MWH	67,547	1,076,748	1,357,620	5,298,345	1,907,153	16,807	56,903	9,781,122	9,781,122
6th Forecast Year	2020	No. of Cust.	2,397	124,739	23,749	11	374	1,015	304	152,589	152,589
		MWH	67,547	1,088,722	1,375,938	5,346,458	1,906,849	16,944	57,131	9,859,589	9,859,589
7th Forecast Year	2021	No. of Cust.	2,397	125,236	24,021	11	376	1,063	306	153,409	153,409
		MWH	67,547	1,093,611	1,388,599	5,347,759	1,899,252	16,941	57,266	9,870,975	9,870,975
8th Forecast Year	2022	No. of Cust.	2,397	125,735	24,293	11	375	1,112	307	154,230	154,230
		MWH	67,547	1,103,120	1,404,045	5,361,331	1,898,813	17,035	57,401	9,909,293	9,909,293
9th Forecast Year	2023	No. of Cust.	2,397	126,165	24,564	11	374	1,158	309	154,978	154,978
		MWH	67,547	1,111,530	1,419,552	5,389,933	1,893,949	17,051	57,571	9,957,134	9,957,134
10th Forecast Year	2024	No. of Cust.	2,397	126,586	24,833	11	372	1,204	310	155,712	155,712
		MWH	67,547	1,122,300	1,439,572	5,433,098	1,888,628	17,183	57,798	10,026,126	10,026,126
11th Forecast Year	2025	No. of Cust.	2,397	126,956	25,107	11	370	1,250	311	156,402	156,402
		MWH	67,547	1,127,022	1,453,153	5,450,764	1,876,487	17,167	57,797	10,049,937	10,049,937
12th Forecast Year	2026	No. of Cust.	2,397	127,476	25,385	11	366	1,294	312	157,241	157,241
		MWH	67,547	1,135,754	1,468,463	5,480,029	1,875,269	17,247	58,054	10,102,362	10,102,362
13th Forecast Year	2027	No. of Cust.	2,397	128,036	25,664	11	363	1,341	313	158,125	158,125
		MWH	67,547	1,145,056	1,484,940	5,509,184	1,874,130	17,298	58,370	10,156,524	10,156,524
14th Forecast Year	2028	No. of Cust.	2,397	128,663	25,946	11	358	1,388	315	159,077	159,077
		MWH	67,547	1,158,738	1,505,777	5,553,365	1,878,679	17,454	58,896	10,240,455	10,240,455

* 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

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	2013	No. of Cust.	2,397	118,917	21,915	9	394	592	287	144,511	144,511
		MWH	67,547	1,018,934	1,256,540	4,851,094	2,022,899	16,066	51,736	9,284,816	9,284,816
Present Year	2014	No. of Cust.	2,397	118,421	21,921	9	378	664	281	144,072	144,072
		MWH	67,547	1,058,986	1,284,024	4,888,265	2,041,484	16,346	54,172	9,410,825	9,410,825
1st Forecast Year	2015	No. of Cust.	2,397	120,668	22,376	10	370	726	290	146,837	146,837
		MWH	67,547	1,034,325	1,287,245	5,152,115	2,025,526	16,380	54,967	9,638,104	9,638,104
2nd Forecast Year	2016	No. of Cust.	2,397	121,846	22,644	11	367	789	293	148,348	148,348
		MWH	67,547	1,049,601	1,310,008	5,343,277	1,899,090	16,654	56,293	9,742,469	9,742,469
3rd Forecast Year	2017	No. of Cust.	2,397	122,805	22,928	11	371	854	297	149,664	149,664
		MWH	67,547	1,056,768	1,326,212	5,259,033	1,866,742	16,738	56,630	9,649,670	9,649,670
4th Forecast Year	2018	No. of Cust.	2,397	123,600	23,205	11	373	910	300	150,796	150,796
		MWH	67,547	1,068,386	1,343,242	5,269,835	1,907,452	16,755	56,906	9,730,122	9,730,122
5th Forecast Year	2019	No. of Cust.	2,397	124,145	23,469	11	374	964	302	151,663	151,663
		MWH	67,547	1,076,748	1,357,620	5,298,345	1,907,153	16,807	56,903	9,781,122	9,781,122
6th Forecast Year	2020	No. of Cust.	2,397	124,739	23,749	11	374	1,015	304	152,589	152,589
		MWH	67,547	1,088,722	1,375,938	5,346,458	1,906,849	16,944	57,131	9,859,589	9,859,589
7th Forecast Year	2021	No. of Cust.	2,397	125,236	24,021	11	376	1,063	306	153,409	153,409
		MWH	67,547	1,093,611	1,388,599	5,347,759	1,899,252	16,941	57,266	9,870,975	9,870,975
8th Forecast Year	2022	No. of Cust.	2,397	125,735	24,293	11	375	1,112	307	154,230	154,230
		MWH	67,547	1,103,120	1,404,045	5,361,331	1,898,813	17,035	57,401	9,909,293	9,909,293
9th Forecast Year	2023	No. of Cust.	2,397	126,165	24,564	11	374	1,158	309	154,978	154,978
		MWH	67,547	1,111,530	1,419,552	5,389,933	1,893,949	17,051	57,571	9,957,134	9,957,134
10th Forecast Year	2024	No. of Cust.	2,397	126,586	24,833	11	372	1,204	310	155,712	155,712
		MWH	67,547	1,122,300	1,439,572	5,433,098	1,888,628	17,183	57,798	10,026,126	10,026,126
11th Forecast Year	2025	No. of Cust.	2,397	126,956	25,107	11	370	1,250	311	156,402	156,402
		MWH	67,547	1,127,022	1,453,153	5,450,764	1,876,487	17,167	57,797	10,049,937	10,049,937
12th Forecast Year	2026	No. of Cust.	2,397	127,476	25,385	11	366	1,294	312	157,241	157,241
		MWH	67,547	1,135,754	1,468,463	5,480,029	1,875,269	17,247	58,054	10,102,362	10,102,362
13th Forecast Year	2027	No. of Cust.	2,397	128,036	25,664	11	363	1,341	313	158,125	158,125
		MWH	67,547	1,145,056	1,484,940	5,509,184	1,874,130	17,298	58,370	10,156,524	10,156,524
14th Forecast Year	2028	No. of Cust.	2,397	128,663	25,946	11	358	1,388	315	159,077	159,077
		MWH	67,547	1,158,738	1,505,777	5,553,365	1,878,679	17,454	58,896	10,240,455	10,240,455

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

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Expressed 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	2013	9,284,816	-	4,013,286	3,979,246	9,555,798	305,022	4,759,658	4,576,504	0
Present Year	2014	9,410,825	-	3,415,095	3,819,839	10,520,059	704,491	4,813,027	4,630,817	0
1st Forecast Year	2015	9,638,104	-	3,689,431	4,049,145	10,731,653	733,836	4,916,919	4,796,562	0
2nd Forecast Year	2016	9,742,469	-	3,682,317	3,642,550	10,484,598	781,896	4,884,875	4,804,501	0
3rd Forecast Year	2017	9,649,670	-	3,936,031	3,578,020	10,069,150	777,491	4,905,966	4,772,031	0
4th Forecast Year	2018	9,730,122	-	4,017,191	3,538,651	10,034,594	783,011	4,934,868	4,808,120	0
5th Forecast Year	2019	9,781,122	-	4,220,574	3,537,240	9,884,402	786,614	4,991,574	4,833,888	0
6th Forecast Year	2020	9,859,589	-	3,759,756	3,424,976	10,317,216	792,407	4,990,117	4,858,949	0
7th Forecast Year	2021	9,870,975	-	3,570,102	3,434,787	10,528,734	793,075	5,009,702	4,873,787	0
8th Forecast Year	2022	9,909,293	-	3,678,758	3,191,222	10,217,717	795,961	5,030,280	4,892,247	0
9th Forecast Year	2023	9,957,134	-	3,564,543	3,238,486	10,430,506	799,428	5,083,268	4,914,793	0
10th Forecast Year	2024	10,026,126	-	3,437,655	3,210,059	10,603,211	804,682	5,085,501	4,933,832	0
11th Forecast Year	2025	10,049,937	-	3,549,770	3,083,437	10,389,712	806,107	5,110,292	4,955,612	0
12th Forecast Year	2026	10,102,362	-	3,496,958	3,066,671	10,481,889	809,813	5,138,054	4,981,628	0
13th Forecast Year	2027	10,156,524	-	3,587,010	3,068,068	10,451,235	813,653	5,196,395	5,006,633	0
14th Forecast Year	2028	10,240,455	-	3,878,121	2,978,388	10,160,529	819,807	5,200,302	5,032,940	0

COMMENTS

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 2013	11.5	168.0	264.3	606.5	377.1	2.7	351.5	1781.5	1781.5

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 2013	1773.9	1754.2	1649.5	1558.4	1570.6	1618.4	1769.8	1781.5	1716.7	1557.9	1688.3	1708.6

COMMENTS
Coincident non-Large Power load at peak hour is approximated by scaling by class energy consumption in peak month

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	2013	Summer								
		Winter								
Present Year	2014	Summer								
		Winter								
1st Forecast Year	2015	Summer								
		Winter								
2nd Forecast Year	2016	Summer								
		Winter								
3rd Forecast Year	2017	Summer								
		Winter								
4th Forecast Year	2018	Summer								
		Winter								
5th Forecast Year	2019	Summer								
		Winter								
6th Forecast Year	2020	Summer								
		Winter								
7th Forecast Year	2021	Summer								
		Winter								
8th Forecast Year	2022	Summer								
		Winter								
9th Forecast Year	2023	Summer								
		Winter								
10th Forecast Year	2024	Summer								
		Winter								
11th Forecast Year	2025	Summer								
		Winter								
12th Forecast Year	2026	Summer								
		Winter								
13th Forecast Year	2027	Summer								
		Winter								
14th Forecast Year	2028	Summer								
		Winter								

COMMENTS

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	2013	Summer							
		Winter							
Present Year	2014	Summer							
		Winter							
1st Forecast Year	2015	Summer							
		Winter							
2nd Forecast Year	2016	Summer							
		Winter							
3rd Forecast Year	2017	Summer							
		Winter							
4th Forecast Year	2018	Summer							
		Winter							
5th Forecast Year	2019	Summer							
		Winter							
6th Forecast Year	2020	Summer							
		Winter							
7th Forecast Year	2021	Summer							
		Winter							
8th Forecast Year	2022	Summer							
		Winter							
9th Forecast Year	2023	Summer							
		Winter							
10th Forecast Year	2024	Summer							
		Winter							
11th Forecast Year	2025	Summer							
		Winter							
12th Forecast Year	2026	Summer							
		Winter							
13th Forecast Year	2027	Summer							
		Winter							
14th Forecast Year	2028	Summer							
		Winter							

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

Capacity- External

NAME OF OTHER UTILITY =>			Laurentian Energy (LEA (Hibb&Virg)	Oliver Cty Wind (ND FPLE 1&2)	Wing River Wind (CBED)	Manitoba Hydro (MHEB)	Minnkota Power Cooperative (MPC)	Xcel Energy
Past Year	2013	Summer	13.1	13.9	0.4	50	0	0
		Winter	13.1	13.9	0.4	50	50	0
Present Year	2014	Summer	13.1	13.9	0.4	50	50	30
		Winter	13.1	13.9	0.4	50	50	30
1st Forecast Year	2015	Summer	13.1	13.9	0.4	50	50	0
		Winter	13.1	13.9	0.4	50	50	0
2nd Forecast Year	2016	Summer	13.1	13.9	0.4	50	50	0
		Winter	13.1	13.9	0.4	50	50	0
3rd Forecast Year	2017	Summer	13.1	13.9	0.4	50	50	0
		Winter	13.1	13.9	0.4	50	50	0
4th Forecast Year	2018	Summer	13.1	13.9	0.4	50	50	0
		Winter	13.1	13.9	0.4	50	50	0
5th Forecast Year	2019	Summer	13.1	13.9	0.4	50	50	0
		Winter	13.1	13.9	0.4	50	50	0
6th Forecast Year	2020	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
7th Forecast Year	2021	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
8th Forecast Year	2022	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
9th Forecast Year	2023	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
10th Forecast Year	2024	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
11th Forecast Year	2025	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
12th Forecast Year	2026	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
13th Forecast Year	2027	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
14th Forecast Year	2028	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>			BEPC	Minnkota Power Cooperative (MPC)
Past Year	2013	Summer	100	50
		Winter	100	0
Present Year	2014	Summer	100	0
		Winter	100	0
1st Forecast Year	2015	Summer	100	0
		Winter	100	0
2nd Forecast Year	2016	Summer	100	0
		Winter	100	0
3rd Forecast Year	2017	Summer	100	0
		Winter	100	0
4th Forecast Year	2018	Summer	100	0
		Winter	100	0
5th Forecast Year	2019	Summer	100	0
		Winter	100	0
6th Forecast Year	2020	Summer	0	0
		Winter	0	0
7th Forecast Year	2021	Summer	0	0
		Winter	0	0
8th Forecast Year	2022	Summer	0	0
		Winter	0	0
9th Forecast Year	2023	Summer	0	0
		Winter	0	0
10th Forecast Year	2024	Summer	0	0
		Winter	0	0
11th Forecast Year	2025	Summer	0	0
		Winter	0	0
12th Forecast Year	2026	Summer	0	0
		Winter	0	0
13th Forecast Year	2027	Summer	0	0
		Winter	0	0
14th Forecast Year	2028	Summer	0	0
		Winter	0	0

COMMENTS

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

			Column 1 SEASONAL MAXIMUM DEMAND	Column 2 SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	Column 3 SEASONAL SYSTEM DEMAND	Column 4 ANNUAL SYSTEM DEMAND	Column 5 SEASONAL FIRM PURCHASES (TOTAL)	Column 6 SEASONAL FIRM SALES (TOTAL)	Column 7 SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	Column 8 ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	Column 9 NET GENERATING CAPABILITY	Column 10 PARTICIPATION PURCHASES (TOTAL)	Column 11 PARTICIPATION SALES (TOTAL)	Column 12 ADJUSTED NET CAPABILITY (9 + 10 - 11)	Column 13 NET RESERVE CAPACITY OBLIGATION	Column 14 TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	Column 15 SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2013	Summer	1782		1782	1782			1782	1782	2058	77	150	1985	191	1972	13
		Winter	1751		1751	1782			1751	1782	1990	127	100	2017	187	1938	79
Present Year	2014	Summer	1727		1727	1772			1727	1772	1885	157	100	1942	185	1912	30
		Winter	1772		1772	1772			1772	1772	1885	157	100	1942	190	1961	-20
1st Forecast Year	2015	Summer	1807		1807	1931			1807	1931	1918	127	100	1945	194	2001	-56
		Winter	1931		1931	1931			1931	1931	1930	127	100	1957	208	2138	-181
2nd Forecast Year	2016	Summer	1923		1923	1958			1923	1958	1942	127	100	1969	207	2129	-160
		Winter	1958		1958	1958			1958	1958	1942	127	100	1969	211	2168	-199
3rd Forecast Year	2017	Summer	1941		1941	1973			1941	1973	1956	127	100	1983	207	2148	-165
		Winter	1973		1973	1973			1973	1973	1956	127	100	1983	211	2184	-201
4th Forecast Year	2018	Summer	1954		1954	1979			1954	1979	1956	127	100	1983	209	2162	-179
		Winter	1979		1979	1979			1979	1979	1956	127	100	1983	212	2191	-208
5th Forecast Year	2019	Summer	1962		1962	1988			1962	1988	1956	127	100	1983	210	2171	-188
		Winter	1988		1988	1988			1988	1988	1956	127	100	1983	213	2201	-218
6th Forecast Year	2020	Summer	1970		1970	1996			1970	1996	1956	277	0	2233	211	2181	53
		Winter	1996		1996	1996			1996	1996	1956	277	0	2233	214	2209	24
7th Forecast Year	2021	Summer	1976		1976	2003			1976	2003	1956	277	0	2233	211	2187	46
		Winter	2003		2003	2003			2003	2003	1956	277	0	2233	214	2217	16
8th Forecast Year	2022	Summer	1982		1982	2010			1982	2010	1936	277	0	2213	212	2195	19
		Winter	2010		2010	2010			2010	2010	2116	277	0	2393	215	2225	168
9th Forecast Year	2023	Summer	1990		1990	2019			1990	2019	2116	277	0	2393	213	2202	191
		Winter	2019		2019	2019			2019	2019	2096	277	0	2373	216	2235	137
10th Forecast Year	2024	Summer	1997		1997	2028			1997	2028	2096	277	0	2373	214	2210	162
		Winter	2028		2028	2028			2028	2028	2076	277	0	2353	217	2245	108
11th Forecast Year	2025	Summer	2004		2004	2035			2004	2035	2076	277	0	2353	214	2218	134
		Winter	2035		2035	2035			2035	2035	2056	277	0	2333	218	2253	79
12th Forecast Year	2026	Summer	2011		2011	2044			2011	2044	2056	277	0	2333	215	2227	106
		Winter	2044		2044	2044			2044	2044	2056	277	0	2333	219	2263	70
13th Forecast Year	2027	Summer	2019		2019	2053			2019	2053	2056	277	0	2333	216	2235	97
		Winter	2053		2053	2053			2053	2053	2056	277	0	2333	220	2273	59
14th Forecast Year	2028	Summer	2027		2027	2063			2027	2063	2056	277	0	2333	217	2244	89
		Winter	2063		2063	2063			2063	2063	2056	277	0	2333	221	2284	49

COMMENTS

Minnesota Power utilizes MISO's ICAP Reserve Capacity calculation and reserve margin assumption of 11.32%

Method for calculating Reserve Capacity Obligation:
[(Peak Demand - Demand Resource) x (1+11.32%)] - Peak Demand + Demand Resource = Net Reserve Capacity Obligation

Net Generating Capability values (column 9) are taken from MISO PY 2014-2015. Available Demand Resource MW is included in Net Generating Capability to balance Load and Capability.

Note: The above table reflects the most current econometric forecast and customer assumptions. Minnesota Power's MISO Peak Demand Submittal for summer of 2014 was based on a non-coincident peak of 1735 MW. The winter peak forecast was 1783 MW. 2013 peak demand values are actuals. Thus, the surplus/ deficit shown in the above table will vary from what was entered in MISO Module E in November 2013.

As shown in Minnesota Power's most recent Integrated Resource Plan, Minnesota Power is in the process of executing a bilateral bridging strategy to address the deficits identified in the 2016-2019 timeframe

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

		ADDITIONS	RETIREMENTS
Past Year	2013		
Present Year	2014		
1st Forecast Year	2015	205	70
2nd Forecast Year	2016		
3rd Forecast Year	2017		
4th Forecast Year	2018		
5th Forecast Year	2019		
6th Forecast Year	2020		
7th Forecast Year	2021		
8th Forecast Year	2022	200	
9th Forecast Year	2023		
10th Forecast Year	2024		
11th Forecast Year	2025		
12th Forecast Year	2026		
13th Forecast Year	2027		
14th Forecast Year	2028		

COMMENTS

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Trade Secret Data Excised

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	SUB	Name of Fuel	FO2	Name of Fuel	WOOD	Name of Fuel	NG	Name of Fuel	HYD	Name of Fuel	WIND
		Unit of Measure	TONS	Unit of Measure	GALLONS	Unit of Measure	TONS	Unit of Measure	MCF	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	2013												
Present Year	2014												
1st Forecast Year	2015												
2nd Forecast Year	2016												
3rd Forecast Year	2017												
4th Forecast Year	2018												
5th Forecast Year	2019												
6th Forecast Year	2020												
7th Forecast Year	2021												
8th Forecast Year	2022												
9th Forecast Year	2023												
10th Forecast Year	2024												
11th Forecast Year	2025												
12th Forecast Year	2026												
13th Forecast Year	2027												
14th Forecast Year	2028												

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-w	SOLAR - Solar
FO6 - Fuel Oil #6 (Residual fuel oil)	STM - Steam	
LIG - Lignite	SUB - Sub-bituminous coal	

COMMENTS

Fuel Requirements for Rapids Energy Center are not shown.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING ~~- FORECAST~~ SECTION

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.

7160.0500 TRANSMISSION LINES

EXISTING TRANSMISSION LINES (200 kV AND ABOVE)

VOLTAGE (kV)	LINE NUMBER	FROM*	TO*	MP OWNED MN MILES	MP TAP MILES	CONDUCTOR MCM TYPE
--------	--------	--------	--------	--------	--------	--------
230 AC	80	FORBES	MINNTAC	25.53		954 ACSR
230 AC	81	ARROWHEAD	BEAR CREEK	55.26		795 ACSR
230 AC	83	BOSWELL	BLACKBERRY	18.4		1431/1590 ACSR
230 AC	90	ARROWHEAD	FORBES	47.53		954 ACSR
230 AC	91	RIVERTON	BADOURA	46.41		795 ACSR
230 AC	92	RIVERTON	BLACKBERRY	67.23		795 ACSR
230 AC	93	BLACKBERRY	FORBES	34.3		954 ACSR
230 AC	94	SHANNON	MCCARTHY LAKE	16.41		1590 ACSR
230 AC	95	BOSWELL	BLACKBERRY	18.84		1431/1590 ACSR
230 AC	96	SHANNON	MINNTAC	23.14		954 ACSR
230 AC	97	RIVERTON	WING RIVER (STAPLES)	35.96		795 ACSR
230 AC	98	BLACKBERRY	ARROWHEAD	64.94	7.01	954 ACSR
230 AC	99	BADOURA	HUBBARD	14.99		795 ACSR
230 AC	100	CALUMET	MCCARTHY LAKE	3.32		1590 ACSR
230 AC	102	BOSWELL	CALUMET	25.86		1590 ACSR
230 AC	902	BEAR CREEK	ROCK CREEK (KETTLE RIVER)	11.8		795 ACSR
230 AC	904	BOSWELL	CASS LAKE***	4.65		795 ACSS
230 AC	907	SHANNON	LITTLEFORK	81.62		954 ACSR
230 AC	909	HUBBARD	AUDUBON (SHELL RIVER)	4.53		795 ACSR
230 AC	R50M	RUNNING	MORANVILLE	7.51		954 ACSR
230 AC	n/a	CASS LAKE	WILTON***	1.77		795 ACSS
250 DC	DC LINE	ARROWHEAD	SQUARE BUTTE (ND BORDER)	231.56		2839 ACSR
345 AC	n/a	MONTICELLO	QUARRY**	4.23		2-954 ACSS/TW
500 AC	601	CHISAGO (KETTLE RIVER)	FORBES (DENHAM)	7.79		3-1192 ACSR
	TOTAL	860.59		853.58	7.01	

* Point of interconnection in parenthesis for partially-owned tie lines

** MP-owned miles represent 14.7% of total circuit mileage under a "tenants in common" model

*** MP-owned miles represent 9.3% of total circuit mileage under a "tenants in common" model

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.

FUTURE TRANSMISSION LINE ADDITIONS (200 kV AND ABOVE)

(enter X for	Built	Retired	VOLTAGE	CONDUCTOR	CONDUCTOR	A.C.	TERMINALS	YEAR IF	MINNESOTA
	x		345 kV	2-954 bundle	ACSS/TW	AC	Quarry - Alexandria	2014	70
	x		345 kV	2-954 bundle	ACSS/TW	AC	Alexandria - Bison	2015	135
	x		500 kV	3-1192 bundle	ACSR	AC	Dorsey - Blackberry	2020	270

COMMENTS

The two 345 kV line additions listed are part of the CapX 2020 Twin Cities-Fargo 345 kV Project. The Monticello-Quarry (St. Cloud) segment of the line was energized in December 2011. Future construction includes a segment between St. Cloud and the Alexandria area and between Alexandria and the Bison Substation in the Fargo area. Minnesota Power will own 14.7% of this line under a "tenants in common" ownership model; the other owners will be Otter Tail Power Company, Missouri River Energy Services, Great River Energy, and Xcel Energy.

The Dorsey-Blackberry 500 kV line is part of the Great Northern Transmission Line Project and is required to deliver MP's 250 MW power purchase agreement (PPA) and 133 MW renewable optimization agreement (ROA) with Manitoba Hydro. Since the project is designed to facilitate up to 750 MW of incremental transfer capability in order to accomodate other Manitoba - U.S. transactions, the ownership structure for the U.S. portion of the project has not yet been determined. This line needs to be in service by 2020 to meet the requirements of MP's PPA and ROA.

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.

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	
	8/20/13	1/21/13	<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	1538	1623	
0200	1506	1615	
0300	1493	1601	
0400	1487	1610	
0500	1495	1600	
0600	1510	1651	
0700	1541	1684	
0800	1589	1691	
0900	1628	1718	
1000	1676	1710	
1100	1730	1717	
1200	1761	1723	
1300	1771	1695	
1400	**1782**	1682	
1500	1770	1717	
1600	1764	1735	
1700	1767	1721	
1800	1753	1718	
1900	1739	**1774**	
2000	1728	1750	
2100	1733	1765	
2200	1720	1745	
2300	1647	1674	
2400	1597	1644	

COMMENTS

PUBLIC DOCUMENT

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133 MW ENERGY SALE AGREEMENT

between

THE MANITOBA HYDRO-ELECTRIC BOARD

- and –

MINNESOTA POWER, an operating division of ALLETE, Inc.

DATED JULY 30, 2014

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133 MW ENERGY SALE AGREEMENT

DATED July 30, 2014

BETWEEN:

THE MANITOBA HYDRO-ELECTRIC BOARD,
(hereinafter referred to as "MH"),

- and –

MINNESOTA POWER, an operating division of ALLETE, Inc.,

(hereinafter referred to as "MP").

WHEREAS, MP and MH are the owners and operators of electric generation facilities in the United States of America and in Canada, respectively, and are engaged in the generation, distribution and sale of electric energy;

AND WHEREAS, MP, MH and 6690271 Manitoba Ltd. entered into a term sheet dated September 27, 2013, (the "**Term Sheet**") for a number of proposed transactions;

AND WHEREAS, each of the aforesaid proposed transactions contemplated by the Term Sheet was subject to a number of conditions including the execution and delivery of definitive written agreements;

AND WHEREAS, this Agreement is the definitive agreement for one of the proposed transactions being the sale by MH and the purchase by MP of the Firm Energy and [TRADE SECRET DATA EXCISED] Environmental Attributes;

AND WHEREAS, MP agrees to purchase and MH agrees to sell the Firm Energy and the [TRADE SECRET DATA EXCISED] Environmental Attributes pursuant to the terms and conditions set forth in this Agreement;

AND WHEREAS, the Parties require governmental permits and approvals for the import and export of electric energy;

AND WHEREAS, MP is a member of MISO and subject to applicable MISO tariffs, and MH is a coordinating member of MISO.

NOW, THEREFORE, in consideration of the mutual promises and covenants of each Party to the other contained in this Agreement and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties covenant and agree as follows:

ARTICLE I
INTERPRETATION

1.1 Defined Terms

Unless otherwise specified in this Agreement, the following terms shall, for the purposes of this Agreement, have the following meanings:

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"**133 MW Canadian TSR**" shall have the meaning set forth in Section 3.1(1)(d)(ii).

"**133 MW US TSR**" shall have the meaning set forth in Section 3.1(1)(a)(ii)(B).

"**250 MW System Power Sale Agreement**" shall mean the 250 MW System Power Sale Agreement entered into between MP and MH on May 19, 2011.

"**500 kV Canadian Transmission Interconnection**" shall have the meaning set forth in Section 3.1(1)(g).

"500 kV Transmission Interconnection" shall have the meaning set forth in Section 3.1(1)(g).

"**500 kV Transmission Interconnection In-service Date**" shall mean when the 500 kV Transmission Interconnection is commissioned and comes into service.

"500 kV US Transmission Interconnection" shall have the meaning set forth in Section 3.1(1)(g).

"500 kV US Transmission Interconnection Miles" shall mean the distance in miles of the 500 kV US Transmission Interconnection.

"**2014 Energy Exchange Agreement**" shall mean the 2014 Energy Exchange Agreement entered into between MP and MH concurrently with this Agreement.

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"Affiliate" shall mean any Person that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with MP or MH, and shall include a wholly owned subsidiary of MP or MH.

"**Agreement**" means this 133 MW Energy Sale Agreement and all amendments thereto.

"[**TRADE SECRET DATA EXCISED**] **Environmental Attributes**" shall have the meaning set forth in Section 8.1(1).

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"Ancillary Services" shall mean those Ancillary Services (as defined under the TARIFF) and other reasonably similar services and products, associated, directly or indirectly, with the transmission of the Firm Energy and/or the transmission of the Firm Energy but for greater certainty does not include Environmental Attributes.

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"**Bankruptcy Code**" shall have the meaning set forth in Section 10.1(1)(k).

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"Business Day" shall mean Monday through Friday, excluding Canadian banking holidays (such banking holidays shall be as recognized by the Canadian Payments Association or any successor agency) and United States banking holidays (such banking holidays shall be as recognized by the Federal Reserve Board or any successor agency).

"**Canadian FCA**" shall have the meaning set forth in Section 3.1(1)(f).

"**Canadian TSRs**" shall have the meaning set forth in Section 3.1(1)(d).

"**Canadian Upgrades**" shall have the meaning set forth in Section 3.1(1)(e).

"**Capital Recovery**" shall have the meaning set forth in Section 2.6(d).

"**Centrally Operated Market**" shall mean a centrally operated structure or structures bringing together buyers and sellers to facilitate the exchange of wholesale electricity products and/or related services.

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"**Commercially Reasonable Efforts**" shall mean those efforts expended by a Party, acting reasonably, under normal commercial conditions to identify, develop, and implement a solution to an issue or problem that is cost effective (taking into account the complexity and importance of the issue or problem being addressed) and is also consistent with applicable legal requirements, rules governing any applicable Market and Good Utility Practice if the Party is MP and Good Hydro Utility Practice is the

Party is MH.

"**Confidential Information**" shall have the meaning set forth in Section 11.1(a).

"Contingency Reserve(s)" shall have the meaning set forth in the NERC Glossary of Terms.

"Contingency Reserves Emergency Energy" shall mean the energy required to be supplied by MH pursuant to a NERC Contingency Reserve obligation.

"**Contract Term**" shall mean the twenty (20) year period, from the 500 kV Transmission Interconnection In-service Date.

"**Contract Year**" shall mean a twelve-month period, June 1 through May 31 of the following calendar year, which is within the Contract Term.

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"CPT" shall mean Central Prevailing Time.

"**Credit Support Provider**" shall mean a Person approved by the Requesting Party who provides Performance Assurance on behalf of the Second Party.

"Day-Ahead Basis" shall mean in advance, not later than 11 a.m. (EST) of the Business Day prior to any day that the Firm Energy is to be made available to MP.

"**Day-Ahead Energy and Operating Reserve Market**" shall mean the day-ahead market established pursuant to and defined by the TARIFF.

"**Day-Ahead Energy Price**" shall have the meaning set forth in the Tariff.

"**DBRS**" shall mean DBRS Limited or its successor.

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"**Defaulting Party**" shall have the meaning set forth in Section 17.3(1).

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"**Delivery Point**" shall have the meaning set forth in Section 2.3(1).

[**TRADE SECRET DATA EXCISED**]

"**Discloser**" shall have the meaning set forth in Section 11.1.

[**TRADE SECRET DATA EXCISED**]

"**EA Calendar Year**" shall have the meaning set forth in Section 8.8.

"**Early Termination Date**" shall have the meaning set forth in Section 17.3(1).

"**Effective Date**" shall mean the date this Agreement is executed by the Parties.

"**Emergency Energy**" shall have the meaning set forth in the TARIFF.

"**Energy Exchange Agreement**" shall mean the Energy Exchange Agreement entered into between MP and MH on May 19, 2011.

"**Environmental Attributes**" shall mean the rights to any existing or future environmental benefits or attributes, credits, renewable characteristics, avoided emissions, avoided greenhouse gas emissions, emission reductions, emissions or greenhouse gas emissions associated with, related to or derived or resulting from the generation of electricity.

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"**Event of Default**" shall have the meaning set forth in Section 17.1.

"**Executive Officers**" shall be, in the case of MH the Vice-President Generation Operations, and in the case of MP the Vice-President of Strategy and Planning or its successor, or such other officer designated by each Party from time to time.

"**FERC**" shall mean the Federal Energy Regulatory Commission or its successor.

"**Firm Energy**" shall have the meaning set forth in Section 2.1(1).

"**Firm Energy Price**" shall have the meaning set forth in Section 4.1.

"**Firm Point-to-Point Transmission Service**" shall have the meaning set forth in the applicable OATT.

"**Firm Power**" shall mean: (a) generating capacity that is intended to be available at all times, except as otherwise agreed by the seller and the purchaser, and for which the seller maintains generation reserves in accordance with standards and requirements established by the RRO to which the seller belongs; and (b) energy that was contracted to be supplied by the seller to the purchaser.

"**Firm Transmission Service**" shall mean transmission service provided pursuant to the OATT of either Party's Transmission Provider, being either Firm Point-to-Point Transmission Service or Network Integration Transmission Service, or the highest priority transmission service available pursuant to either Party's OATT, or in the event that either Party does not have an OATT, the highest priority transmission service available to that Party for the delivery of energy and the supply of capacity.

"**Force Majeure**" shall mean an event or circumstances that prevents or delays one Party (the "**Claiming Party**") from performing its obligations under this Agreement and that is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and that, by the exercise of Good Utility Practice, if the Claiming Party is MP and the exercise of Good Hydro Utility Practice if the Claiming Party is MH, unable to overcome or avoid or cause to be avoided, including but not restricted to, acts of God, [**TRADE SECRET DATA EXCISED**], strikes, lockouts and other labour disturbances, epidemics, pandemic, war (whether or not declared), blockades, acts of public enemies, acts of sabotage or terrorism, civil insurrection, riots or civil disobedience, any situation where delivery or acceptance will endanger the Claiming Party's facilities or endanger that Party's system operations, explosions, acts or omissions of any Governmental Authority taken on or after the Effective Date, (including the adoption or change in any law or regulation lawfully imposed by such Governmental Authority) but only if, and to the extent that, such action or inaction by such Governmental Authority prevents or delays the Claiming Party's performance and/or renders the Claiming Party unable, despite due diligence, to obtain any licenses, permits, or approval required by any Governmental Authority, and the issuance of any order, injunction, or other legal or equitable decree, if any, to the extent that any of the foregoing prevents or delays the performance of the Claiming Party's obligations hereunder. As used in this Agreement, an event or circumstance can "prevent" a Party's performance not only if it physically prevents such performance, but also if it renders such performance unlawful.

"**Good Hydro Utility Practice**" shall mean, at any particular time, any of the practices, methods, and acts engaged in or approved by a significant portion of the hydro-electric utilities located in North America during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could be expected to produce the desired result at a reasonable cost consistent with reliability, safety, and expedition. Good Hydro Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but includes a range of acceptable practices, methods, or acts.

"**Good Utility Practice**" shall mean, at any particular time, any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utilities located in North America during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could be expected to produce the desired result at a reasonable cost consistent with reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but includes a range of acceptable practices, methods, or acts.

"**Governmental Authority**" shall mean any federal, state, or provincial government, parliament, legislature, or any regulatory authority, agency, bureau, department, commission or board of any of the foregoing, or any political subdivision thereof, or any court or administrative tribunal, or, without limitation, any other law, regulation or rule-making entity, having jurisdiction in the relevant circumstances, or any Person acting under the authority of any of the foregoing, or any other authority charged with the administration or enforcement of applicable laws.

"**Governmental Charges**" shall mean all applicable federal, state, provincial and local ad valorem, property, occupation, severance, generation, first use, conservation, or energy, transmission, utility, gross receipts, privilege, sales, use, goods and services, consumption, excise and other taxes, charges, emission allowance costs, duties, tariffs, levies, licenses, fees, permits, assessments, adders or surcharges (including public purposes charges and low income bill payment assistance charges), imposed or authorized by a Governmental Authority, independent system operator, utility, transmission and/or distribution provider or similar Person, however styled or payable.

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"**Guarantee Agreement**" shall mean a guarantee provided to the Requesting Party by a Credit Support Provider with an Investment Grade Credit Rating as Performance Assurance pursuant to Section 14.2(1) in a form acceptable to the Requesting Party acting with commercially reasonable discretion.

"Interest" shall have the meaning set forth in Section 2.6(e).

"**Interest Rate**" shall mean, for any date, the lesser of: (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in The Wall Street Journal under "Money Rates" on such day (or if not published on such day, on the most recent preceding day on which published), plus two percent (2%); and (b) the maximum rate permitted by applicable law.

"**Investment Grade Credit Rating**" shall mean with respect to any Person, a rating (unenhanced by unaffiliated third party support) of not less than:

(a) BBB- from S&P; or

(b) Baa3 from Moody's; or

(c) BBB(low) from DBRS,

then assigned to the lower of:

(i) its unsecured, senior long-term debt obligations; or

(ii) if applicable, its issuer rating,

in each instance, unenhanced by unaffiliated third party support and not on “credit watch” or “negative outlook”, provided, however, that in the event that such Person has a rating from one of the aforesaid rating agencies below the required level, the lowest such rating shall apply for the purposes of this definition.

“**Letter(s) of Credit**” shall mean one or more irrevocable, transferable, standby letters of credit, issued by a commercial bank, as defined in either the Federal Deposit Insurance Act (United States) or the Bank Act (Canada), or successor legislation, operating from an office in either the United States or Canada whose credit rating is, at such time of issuance, at least “A-’’ by S&P or “A3” by Moody’s or A(low) by DBRS, or an equivalent rating by any successor rating agency thereof (if any), in a form as the issuing bank may request and as may be acceptable in a commercially reasonable manner to the Party in whose favor the Letter of Credit is issued.

"**Letter of Credit Default**" shall mean with respect to an outstanding Letter of Credit, the occurrence of any of the following events: (a) the issuer of the Letter of Credit shall fail to maintain a credit rating of at least “A-” by S&P or “A3” by Moody’s or A(low) by DBRS; (b) the issuer of such Letter of Credit shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of, such Letter of Credit; (c) such Letter of Credit shall expire or terminate, or shall fail or cease to be in full force and effect, at any time during the Contract Term; (d) any event analogous to an event specified in Section 17.1(c), (d),(e) or (g) of this Agreement shall occur with respect to the issuer of such Letter of Credit; or (e) twenty (20) Business Days prior to the expiration or termination date of such Letter of Credit, such Letter of Credit has not been extended or replaced with a Letter of Credit for an amount at least equal to that of the Letter of Credit being replaced.

"**Market**" or "**Markets**" shall mean:

(a) a Centrally Operated Market; and/or

(b) the wholesale purchase and sale of electricity products and/or related services on a bilateral basis.

"**Market Participant**" shall have the meaning set forth in the TARIFF.

"**Market Portal**" shall have the meaning set forth in the TARIFF.

"**Market Settlement Amounts**" shall mean any and all charges attributable to either Party arising out of a process of determining charges established and maintained at any time and from time to time by a Market (or a Transmission Provider).

"**Median Water**" means [**TRADE SECRET DATA EXCISED**]

"**MH Minimum Annual Energy Decrement Event**" shall have the meaning set forth in Section 3.4(2).

"**MH/MP Agreements**" shall mean this Agreement, the 250 MW System Power Sale Agreement, the Energy Exchange Agreement and the 2014 Energy Exchange Agreement.

"**MH OASIS**" shall mean the "Open Access Same-Time Information System" used by MH.

"**MH Termination Event**" shall have the meaning set forth in Section 17.4.

"**MH's Border Accommodation Power Sales**" shall mean those sales of Firm Power made by MH, as seller, which for some purposes are treated by MH as part of MH's End-Use Load, to Persons located in provinces and states adjacent to the province of Manitoba in circumstances whereby electric service to those locations is not otherwise readily available from other power suppliers. In all cases, these sales are made over transmission systems lower than 115 kV.

"**MH's Conditions Precedent**" shall have the meaning set forth in Section 12.1.

"**MH's Curtailment of Cleared Firm Energy**" shall have the meaning set forth in Section 3.4(4).

"**MH's Electrical Generation Facilities**" shall mean MH's electrical generation facilities that are either owned and operated or operated by MH.

"**MH's End-Use Load**" shall mean: (a) the total load of Persons that purchase electric service from MH for their own consumption in the province of Manitoba and not for resale including any portion of that Person's load that may from time to time not be supplied by MH but may be produced by that Person; (b) MH's Border Accommodation Power Sales; and (c) MH's Separated Load Sales.

"**MH's Energy Commitments**" shall mean the energy required by MH to serve the total of the following obligations of MH: (a) MH's End-Use Load; (b) all energy sales by MH that are associated with planning capacity; and (c) all energy sales that are not associated with planning capacity including all of MH's Firm LD Energy Sales and MH's Firm Energy Sales.

"**MH's Energy Resources**" shall mean the sources of generation identified in Appendix "B", as such Appendix is revised from time to time.

"**MH's Firm Energy Sales**" shall mean those sales by MH described as "Firm Energy Sales" in agreements entered into between MH and third Persons.

"**MH's Firm LD Energy Sales**" shall mean those sales by MH described as "Firm LD Sales" in agreements entered into between MH and third Persons.

"**MH's HVDC System**" shall mean MH's high voltage direct current transmission system.

"**MH's Real Time Energy"** shall have the meaning set forth in Section 3.2(9).

"**MH's Required Approval**" shall have the meaning set forth in Section 12.3.

"**MH's Separated Load Sales**" shall mean those sales of energy made by MH, as seller, which are treated by MH as part of MH's End-Use Load, to Persons located in provinces and states adjacent to the Province of Manitoba in circumstances whereby electric service to those locations becomes separated due to forced outages, planned outages, or scheduled outages by the applicable Transmission Provider, from the said province or state adjacent to the Province of Manitoba and such outages require electric service to be provided by MH until electric service is restored.

"**MH's Wind Energy**" shall mean all energy: (a) that is generated by a wind generation facility that is part of MH's integrated power system; or (b) was purchased by MH from a wind generation facility.

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"**Minimum Annual Energy Amount**" shall have the meaning set forth in Section 2.1(1)(b).

"**MISO**" shall mean the Midcontinent Independent System Operator, Inc.

"**MISO OASIS**" shall mean "MISO's Open Access Same-Time Information System" as defined in the TARIFF.

"**Moody's**" shall mean Moody's Investors Service Inc. or its successor.

"**MP Minimum Annual Decrement Event**" shall have the meaning set forth in Section 3.8(3).

"MP's Required Approval" shall have the meaning set forth in Section 12.3.

"**MP Termination Event**" shall have the meaning set forth in Section 17.5.

"**MP's Conditions Precedent**" shall have the meaning set forth in Section 12.2.

"MP's Curtailment of MH's Cleared Energy" shall have the meaning set forth in Section 3.8(2).

"MPUC" shall mean the Minnesota Public Utilities Commission or any successor state regulatory commission of competent jurisdiction.

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"**MRO**" shall mean the Midwest Reliability Organization or successor regional reliability organization, or any committee or subcommittee thereof.

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[**TRADE SECRET DATA EXCISED**]

"**NEB**" shall mean the National Energy Board of Canada or its successor.

"**NERC**" shall mean the North American Electric Reliability Corporation or its successor.

"**Net Scheduled Interchange**" shall have the meaning set forth in the TARIFF.

"**Network Integration Transmission Service**" shall have the meaning set forth in the applicable OATT.

"**Non-defaulting Party**" shall have the meaning set forth in Section 17.3(1).

"**Non-Disclosure Agreement**" shall mean that certain non-disclosure agreement between the Parties, dated November 11, 2011.

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"**On-Peak Hours**" shall mean HE 7:00 CPT to HE 22:00 CPT Monday to Friday.

"**Open Access Transmission, Energy and Operating Reserve Markets Tariff**" or "**TARIFF**" shall mean the Open Access Transmission, Energy and Operating Reserve Markets FERC Electric Tariff, including all schedules and attachments thereto, of the Midcontinent Independent System Operator, Inc. issued on May 1, 2013, as amended, supplemented, or replaced from time to time.

"**Open Access Transmission Tariff**" or "**OATT**" shall mean a transmission tariff as it may be in effect from time to time that: (a) in the case of MP's Transmission Provider, has been filed with and accepted by FERC as complying with FERC's then current open access transmission, comparability, and non-discrimination requirements; and (b) in the case of MH, provides reciprocal open access transmission service on sufficiently comparable and non-discriminatory terms so as to entitle MH to use the transmission tariff of Transmission Providers in the United States; and (c) in the case of a third party, has been filed with and accepted by FERC as complying with FERC's then current open access transmission, comparability, and non-discrimination requirements, or provides reciprocal open access transmission service on sufficiently comparable and non-discriminatory terms so as to entitle such entity to transmit electricity with entities whose transmission tariff has been filed with and accepted by FERC as a transmission tariff.

"**Operating Committee**" shall have the meaning set forth in Section 9.1(1).

"**Party**" shall mean either MH or MP and "**Parties**" means both MH and MP.

"**Performance Assurance**" shall have the meaning set forth in Section 14.2(1).

"**Person**" shall mean an individual, partnership, corporation, limited liability company, trust, unincorporated association, syndicate, joint venture, or other entity or Governmental Authority.

"**Pledgor**" shall have the meaning set forth in Section 14.3(1).

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"**Priority Criteria**" shall have the meaning set forth in Section 3.5.

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"**Purchase and Sale Exclusion Event(s)**" shall mean any or all of the following events or circumstances: (a) MH's offer in respect of any amount of the Firm Energy, does not clear the Day-Ahead Energy and Operating Reserve Market; or (b) the curtailment, restriction, or reduction of any portion of the Firm Energy pursuant to Sections 3.4, 3.7 or 3.8 or Article XIII.

"**Real-Time Energy and Operating Reserve Market**" shall mean the Market for purchases and sales of Energy and Operating Reserve conducted by the Transmission Provider during the Operating Day, each as defined in and in accordance with the TARIFF.

"**Real Time Energy Price**" shall have the meaning set forth in Section 3.2(9).

"**Recipient**" shall have the meaning set forth in Section 11.1.

"**Representative**" shall have the meaning set forth in Section 11.1(b)(i).

"**Requesting Party**" shall have the meaning set forth in Section 14.2(1).

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"**RRO**" shall mean a regional reliability organization, including the MRO, if applicable.

"**S&P**" shall mean Standard & Poor's Services Group (a division of McGraw-Hill Inc.) or its successor.

"**Seams Costs**" shall mean any and all transmission and transmission service and related costs applied by one Market for the transmission of energy and related products from that Market or to that Market at the boundary of that Market.

"**Schedule**" or "**Scheduling**" shall mean the actions of seller, buyer, and their designated representatives, of notifying, requesting, and confirming to each other the quantity of the Firm Energy and/or Ancillary Services to be delivered on any given day or days during the Contract Term.

"**Scheduled**" shall mean the result of Scheduling.

"**Second Party**" shall have the meaning set forth in Section 14.2(1).

"**Secured Party**" shall have the meaning set forth in Section 14.3(1).

"**Supplied Energy**" shall mean that portion of the Firm Energy that was, pursuant to this Agreement, supplied and sold by MH attributable to MH's Energy Resources and for greater certainty shall not include any amount of the Firm Energy that was: (a) offered by MH but did not clear the Day-Ahead Energy and Operating Reserve Market; or (b) curtailed, restricted or reduced pursuant to Sections 3.4, 3.7 or 3.8 or Article XIII.

"**Term Sheet**" shall have the meaning set forth in the preamble.

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"**Transfer System**" shall have the meaning set forth in Section 8.4(2).

"**Transmission Minimum Annual Energy Decrement Event**" shall have the meaning set forth in Section 3.7(3).

"**Transmission Provider(s)**" shall mean, collectively, the Person or Persons as applicable who direct the operation of the Transmission Provider(s) System.

"**Transmission Provider(s) System**" shall mean the contiguously interconnected electric transmission and sub-transmission facilities, including land rights, material, equipment and facilities owned, controlled, directed, and/or operated by the Transmission Provider(s) that transmits and distributes electrical energy.

"**Transmission Service**" shall mean the Firm Transmission Service referred to in Sections 3.1(2), and 3.1(4).

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"Unavailability of MH's Purchased or Sold Power" shall mean: (a) when all or a portion of capacity and/or energy, purchased from Persons, including from Markets outside the province of Manitoba, are unavailable to MH, due to curtailments, restrictions or reductions of the capacity and/or energy purchased in accordance with the provisions of one or more of the applicable power purchase agreements; or (b) where MH does not have access on commercially reasonable terms to Markets in the United States to purchase and import energy and/or capacity into MH's integrated power system despite using Commercially Reasonable Efforts to gain such access; or (c) when the TARIFF or any MISO Business Practices Manual is revised to the extent that they unreasonably restrict MH's ability to export power into the MISO market.

"**Unavailability of MH's Purchased Power**" shall mean: (a) when all or a portion of the energy purchased by MH from MP (including any assignee of MP) is not received by MH, under the provisions of one or more of the applicable energy or power purchase agreements (if any) between MH and MP (including without limiting the generality of the foregoing due to curtailment or force majeure thereunder) unless the said energy is not received by MH due to MH being in default under the provisions of the applicable agreement; or (b) the occurrence of an uncured "Event of Default" (as defined in the Energy Exchange Agreement) by MP under the Energy Exchange Agreement; or (c) the occurrence of an uncured "Event of Default" (as defined in the 2014 Energy Exchange Agreement) by MP under the 2014 Energy Exchange Agreement.

"**U.S. Dollars**" **or** "**US $**" shall mean lawful money of the United States of America.

"US Business Day" shall mean Monday through Friday, excluding United States banking holidays (such banking holidays shall be as recognized by the Federal Reserve Board or any successor agency).

"**US FCA**" shall have the meaning set forth in Section 3.1(1)(c).

"**US TSRs**" shall have the meaning set forth in Section 3.1(1)(a).

"**US Upgrades**" shall have the meaning set forth in Section 3.1(1)(b).

"**Use Limited System Installed Capacity**" shall mean the value attributed to electrical generating capacity based on generator testing data required to be provided by MH to MISO on an annual basis pursuant to MISO's generator testing requirements and that due to design considerations, environmental restrictions on operations, cyclical requirements such as the need to recharge or refill, or for other non-economic reasons, is or may be unable to operate continuously on a daily basis, but is capable of providing energy for a minimum of four (4) continuous hours of each day during the expected peak load of the system operator to which the purchaser belongs during the term of the applicable power purchase and sale agreement. For greater certainty, Use Limited System Installed Capacity does not include any generation reserves.

"**WPS**" shall have the meaning set forth in Section 3.1(1)(a)(ii).

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1.2 Interpretation

Unless the context otherwise requires, this Agreement shall be interpreted in accordance with the following:

(a) words singular and plural in number shall be deemed to include the other and pronouns having masculine or feminine gender shall be deemed to include the other;

(b) any reference in this Agreement to any Person, includes its successors and permitted assigns, and, in the case of any Governmental Authority, any Person succeeding to its functions and capacities;

(c) any reference in this Agreement to any section or Appendix means and refers to the section contained in, or Appendix attached to, this Agreement;

(d) other grammatical forms of defined words or phrases have corresponding meanings to the defined words or phrases;

(e) a reference to writing includes typewriting, printing, lithography, photography, and any other mode of representing or reproducing words, figures or symbols in a lasting and visible form, including electronic mail;

(f) a reference to a Party to this Agreement includes that Party's successors and permitted assigns;

(g) a reference to a document or agreement, including this Agreement, includes a reference to that document or agreement as amended from time to time and includes any exhibits or attachments thereto;

(h) headings are inserted for convenience only and shall not affect the interpretation of this Agreement or any section thereto;

(i) the preamble hereto shall form an integral part of this Agreement; and

(j) the word "including" means "including without limitation".

1.3 <u>No Presumption</u>

The Parties are both represented by counsel, have both participated in the negotiation and drafting of this Agreement, and have endeavoured to ensure that the terms of this Agreement are as clear as possible. Accordingly, in interpreting this Agreement there shall be no presumption in favour of or against any Party on the basis that it was or was not the drafter of this Agreement or any individual provision thereof.

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ARTICLE II

SUPPLY AND PURCHASE OBLIGATIONS

2.1 Offers of Energy

(1) During each day of the Contract Term, MH shall sell to MP and MP shall purchase from MH such quantity of energy, if any, that MH determines for that day on a Day Ahead Basis that it has available for sale to MP, and is offered by MH to MP, on a Day Ahead Basis (the "**Firm Energy**") provided that:

(a) the energy so offered for each hour in that day shall not exceed 133 MWh per hour; and

(b) so long as MH has experienced Median Water during a Contract Year during the Contract Term, as determined by MH on or before 120 calendar days after the end of such Contract Year, MH agrees that during such Contract Year, it shall have offered and made available, in accordance with Article III, a minimum of [**TRADE SECRET DATA EXCISED**] MWh of energy (the "**Minimum Annual Energy Amount**").

(2) MH agrees to provide to MP, within 180 days of the end of each Contract Year, of the quantity of hydraulic generation that was generated by MH in that Contract Year from MH's integrated power system.

(3) The Parties acknowledge that the Firm Energy has no Use Limited System Installed Capacity component and has no other capacity component except for operating capacity only in the event of and to the extent MH is required to make the Firm Energy available to MP in accordance with this Agreement.

2.2 Firm Energy

MH shall during the Contract Term, offer and make available the Firm Energy to the Delivery Point and MP shall accept delivery of and pay for the Firm Energy or alternatively, pay for the Firm Energy if not taken. The Parties acknowledge that the quantity of Firm Energy sold by MH and purchased by MP is impacted by the provisions of Section 3.2. The Parties further acknowledge MH would not be required to make available to MP, and MP would not be required to accept delivery of and pay for, or pay for if not taken, that quantity of Firm Energy that was curtailed, restricted or reduced pursuant to and in accordance with the provisions of Sections 3.4, 3.7 or 3.8 or if the additional Force Majeure provisions of Article XIII apply.

2.3 Delivery Point

(1) The Parties agree that the delivery point for the Firm Energy that is sold by MH and purchased by MP under this Agreement shall be at the point or points where MH's major transmission facilities cross the international boundary between the Province of Manitoba and the United States of America (the "**Delivery Point**").

(2) The Delivery Point for any portion of the Firm Energy to be sold and purchased herein may only be changed with the consent of the Parties, provided that the Party receiving a request from the other Party to change the Delivery Point must use Commercially Reasonable Efforts in responding to such request.

2.4 Title and Risk of Loss

Title to and risk of loss of the Firm Energy sold and purchased under this Agreement shall pass from MH to MP at the Delivery Point.

2.5 Ancillary Services

(1) MP acknowledges and agrees that: (a) MH shall be entitled to retain all Ancillary Services; (b) MH shall be entitled to sell the Ancillary Services to other Persons through use of the Market Portal or otherwise and without limiting the generality of the foregoing, MH has the right to offer and/or schedule the Ancillary Services into the MISO market including in conjunction with Schedules for the delivery of the Firm Energy to MP in accordance with Section 3.2 or, in MH's sole discretion through the use of the Market Portal; (c) the price for the Firm Energy does not include any value in

respect of or related to the Ancillary Services; and (d) MP shall use Commercially Reasonable Efforts to comply with all reasonable requests of MH concerning the Firm Energy and MH's participation in any Market in respect of or related to the Ancillary Services.

(2) If MH's offer in respect of the Ancillary Services associated with a quantity of Firm Energy clears the Day-Ahead Energy and Operating Reserve Market, the Parties acknowledge that MH shall have no obligation to make available such quantity of energy to MP and MP shall have no obligation to pay for such quantity of energy, but MH shall continue to otherwise have an obligation to make available in accordance with Articles 2 and 3 that portion, if any, of the Firm Energy that MH offered into and cleared the Day-Ahead Energy and Operating Reserve Market and MP shall be obligated to pay for same.

(3) MP shall, if required pursuant to the Market mechanisms in effect at the applicable time, approve any valid NERC E-Tag, prepared pursuant to and in accordance with the applicable Market procedures, associated with any offer of Ancillary Services made by MH pursuant to this Agreement into the Day-Ahead Energy and Operating Reserve Market and MP shall take such other actions as may be reasonably requested by MH pursuant to the Market mechanisms in effect at the applicable time in respect of such offers.

(4) In the event that MP receives any compensation or payment from MISO or otherwise for Ancillary Services that were offered or scheduled by MH, MP shall remit such compensation or payment to MH or MP shall request the MISO redirect any such compensation or payments to MH.

2.6 Must Take Fee

MH shall make monthly payments during the Contract Term to MP in accordance with Sections 5.5 and 5.6 in each calendar month of each MTF Contract Year (excluding the last calendar month of the Contract Term) determined by the sum of the amounts calculated pursuant to Sections 2.6 (a), (b), (c), (d), (e), and (f) for such MTF Contract Year ("Monthly Must Take Fee") as follows:

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2.7 Additional Purchase of Energy and/or Power

MH and MP agree to enter into negotiations prior to the end of the Contract Term for additional purchases and sales of energy and/or power on mutually agreeable terms utilizing the available capacity of the 500 kV Transmission Interconnection, provided, however that failure to reach any agreement shall not affect any agreements between MH and MP.

ARTICLE III
SCHEDULING AND DELIVERY

3.1 Transmission

(1) The Parties acknowledge and agree:

(a) Transmission service requests have been filed on the MISO OASIS:

(i) by MH for 883 MW of northbound transfer capability;

(ii) by MP, MH and Wisconsin Public Service Corporation ("**WPS**") for 883 MW of southbound transfer capability which includes:

(A) MP pursuant to transmission service request 76703672 for 250 MW of southbound transfer capability; and

(B) MP pursuant to transmission service request number 79258361 for 133 MW of southbound transfer capability (the "**133 MW US TSR**"); (such filed transmission service requests collectively the "**US TSRs**"),

and for recognition of such transfer capability as Firm Transmission Service under the TARIFF;

(b) to accommodate the US TSRs, additions, alterations, and improvements will be required to MP's transmission system (the "**US**

Upgrades" which includes without limitation, the 500 kV US Transmission Interconnection);

(c) a facilities construction agreement would be required to be entered into in accordance with the requirements of MISO for the construction and maintenance of the US Upgrades (the "**US FCA**");

(d) MH has filed individual transmission service requests on the MH OASIS (such filed transmission service requests collectively the "**Canadian TSRs**") for:

(i) a total 883 MW of northbound transfer capability; and

(ii) a total 883 MW of southbound transfer capability which includes:

(A) 133 MW of southbound transfer capability pursuant to transmission service request number 79622799 (the "**133 MW Canadian TSR**");

and for recognition of such transfer capability as Firm Transmission Service under MH's OATT;

(e) to accommodate the Canadian TSRs, additions, alterations, and improvements will be required to MH's Transmission Providers transmission system (the "**Canadian Upgrades"** which includes without limitation, the 500 kV Canadian Transmission Interconnection");

(f) a facilities construction agreement would be required to be entered into in accordance with the requirements of MH's Transmission Provider for the construction and maintenance of the Canadian Upgrades (the "**Canadian FCA**");

(g) the US Upgrades and the Canadian Upgrades are expected to consist of the United States portion and the Canadian portion, respectively, of a new 500 kilovolt international transmission interconnection utilizing a route between the Dorsey sub-station in Manitoba and the Blackberry sub-station near Grand Rapids, Minnesota (the Canadian and United States components of the said transmission interconnection collectively referred to the "**500 kV Transmission Interconnection**")(the United States component of the 500 kV Transmission Interconnection referred to as the "**500 kV US Transmission Interconnection**")(the Canadian component of the 500 kV Transmission Interconnection referred to as the "**500 kV Canadian Transmission Interconnection**");

(h) if a Canadian FCA is entered into, MH agrees it will fund all of the costs for constructing the Canadian Upgrades on the conditions and terms set out in the Canadian FCA and will comply with the provisions of such agreement;

(i) if a US FCA is entered into, MH agrees it will contribute or cause an Affiliate of MH to contribute to the costs for constructing and maintaining the US Upgrades on the conditions and terms set out in the US FCA or otherwise by separate agreement with MH and/or its Affiliate and MP, and MH and/or its Affiliate and MP, as applicable, agree to comply with the provisions of such agreement(s); and

(j) if a US FCA is entered into, MP agrees it will contribute to the costs for constructing and maintaining the US Upgrades on the conditions and terms set out in the US FCA or otherwise by separate agreement with MH and/or its Affiliate, as applicable, and MP agrees it will comply with the provisions of such agreement(s).

(2) MH acknowledges and agrees that the Canadian Upgrades, if built and completed, shall enable the provision of Firm Transmission Service in respect

of the purchase of the Firm Energy that is made available and sold by MH pursuant to this Agreement to the Delivery Point, subject to:

(a) MH receiving from MH's Transmission Provider pursuant to MH's OATT, 133 MW of southbound Firm Transmission Service in respect of the 133 MW Canadian TSR as a result of the Canadian Upgrades being constructed and placed in-service.

(3) MH agrees:

(a) to use Commercially Reasonable Efforts to obtain the Firm Transmission Service referred to in Section 3.1(2)(a) above; and

(b) subject to Sections 3.1(1) and 3.1(2)(a) to arrange and pay for Firm Transmission Service for the delivery of the Firm Energy to be made available and sold by MH pursuant to this Agreement to the Delivery Point. Without limiting the generality of the foregoing, MH shall be responsible for the payment of any and all Market Settlement Amounts, transmission charges and associated charges, congestion charges, transmission loss charges and/or transmission energy losses, and all other charges assessed by MH's Transmission Provider for the delivery of the Firm Energy made available and sold by MH pursuant to this Agreement to the Delivery Point. For greater certainty, no provision of this Agreement shall obligate MH and/or any Affiliate of MH to pay for any of the costs of constructing, operating or maintaining the Canadian Upgrades, or any of the costs of constructing, operating and maintaining the US Upgrades and such obligations, will be as set out in the Canadian FCA and the US FCA, as applicable.

(4) MP acknowledges and agrees that the US Upgrades, if built and completed, shall enable the provision of Firm Transmission Service, in respect of the purchase of the Firm Energy that is sold by MH and purchased by MP pursuant to this Agreement, from the Delivery Point, subject to:

(a) MP receiving from MISO, pursuant to the TARIFF, 133 MW of southbound Firm Transmission Service in respect of the 133 MW US TSR as a result of the US Upgrades being constructed and placed in-service.

(5) MP agrees:

(a) to use Commercially Reasonably Efforts to obtain the Firm Transmission Service referred to in Section 3.1(4)(a); and

(b) subject to Sections 3.1(1) and 3.1(4)(a), to arrange and pay for Firm Transmission Service for the delivery of the Firm Energy to be received and purchased by MP pursuant to this Agreement from the Delivery Point. Without limiting the generality of the foregoing, MP shall be responsible for the payment of any and all Market Settlement Amounts, transmission charges and associated charges, congestion charges, transmission loss charges and/or transmission energy losses, and all other charges assessed by MP's Transmission Provider for the delivery of the Firm Energy received and purchased by MP pursuant to this Agreement from the Delivery Point. For greater certainty, no provision of this Agreement shall obligate MP to pay for any of the costs of constructing, operating or maintaining the US Upgrades and such obligations, will be as set out in the US FCA.

3.2 Offers and Scheduling

(1) MP shall be required to Schedule any of the Firm Energy that has been offered on a Day-Ahead Basis by MH. The Firm Energy that is Scheduled shall be Scheduled using the Transmission Service.

(2) The price at which MH offers all of the Firm Energy pursuant to this Agreement, into the Day-Ahead Energy and Operating Reserve Market, shall be at the sole discretion of MH.

(3) All Firm Energy that is to be Scheduled shall be Scheduled and provide for

delivery up to 133 MWh per hour, over the applicable hour(s) that MH offered Firm Energy on a Day-Ahead Basis during the Contract Term.

(4) MP shall, if required pursuant to the Market mechanisms in effect at the applicable time, approve any valid NERC E-Tag, prepared pursuant to and in accordance with the applicable Market procedures, associated with any offer of Firm Energy made by MH pursuant to this Agreement into the Day-Ahead Energy and Operating Reserve Market and MP shall take such other actions as may be reasonably requested by MH pursuant to the Market mechanisms in effect at the applicable time in respect of such offers.

(5) During any hour during the Contract Term that a Purchase and Sale Exclusion Event has occurred, MH shall have no obligation to sell and make available, and MP shall have no obligation to purchase and receive, that quantity of the Firm Energy that is subject to or otherwise applicable to the Purchase and Sale Exclusion Event.

(6) The Parties shall during the Contract Term Schedule the Firm Energy in a manner that would enable MH to satisfy its obligations under this Agreement utilizing MH's resources, (which includes MH's Electrical Generation Facilities), and/or third party purchases, and/or Markets available to MH and the right to utilize any market mechanisms that are available to MH throughout the Contract Term to satisfy its obligations under this Agreement. Without limiting the generality of the foregoing, the Parties agree that the Market Portal may be utilized at MH's sole discretion to offer and/or Schedule into the MISO market. The Parties further agree that if: [**TRADE SECRET DATA EXCISED**]

(7) Each Party shall be responsible for and pay its own costs and expenses associated with the purchase and sale of the Firm Energy under the applicable OATT and/or TARIFF, including without limitation, any Market Settlement Amounts.

(8) MH shall, where required to submit an offer or electing to submit an offer in

the Day-Ahead Energy and Operating Reserve Market for the Firm Energy, subject to the provisions of Section 3.2(10) use a Dispatchable Interchange Schedule with an Offer, in the Day-Ahead Energy and Operating Reserve Market in order to satisfy its obligations under this Agreement, based on the present Scheduling practices and procedures of the TARIFF. MH shall, subject to the provisions of Section 3.2(10), submit such Dispatchable Interchange Schedule with an Offer in accordance with the timing requirements of the MISO Business Practices Manuals. MP shall approve, if required pursuant to the Market mechanisms in effect at the applicable time, the Dispatchable Interchange Schedule with an Offer submitted by MH pursuant to this Agreement and take such other actions as may be reasonably requested by MH pursuant to the Market mechanisms in effect at the applicable time in respect of such Dispatchable Interchange Schedule with an Offer. Notwithstanding the foregoing, including Section 3.2(3), MH may in its sole discretion, utilize the Market Portal to Schedule and/or offer into the MISO market.

(9) MP acknowledges that during the Contract Term, MH shall have the right to sell energy ("**MH's Real Time Energy**"), at the Delivery Point, to MP or to the MISO market, using the Transmission Service capability that has not otherwise been utilized under this Agreement, and the Real-Time Energy and Operating Reserve Market: (a) subject to MH paying all incremental Market Settlement Amounts, if any, charged to MP that were directly related to MH's offer of energy pursuant to this Section 3.2(9) into the Real-Time Energy and Operating Reserve Market; (b) subject to MH receiving the benefit of any Market Settlement Amounts referred to in (a) above; (c) [**TRADE SECRET DATA EXCISED**] The Operating Committee shall make and implement decisions and procedures regarding the sale and purchase and delivery and receipt of MH's Real Time Energy.

(10) As of the Effective Date, the Parties are Market Participants and the terms of Section 3.2(8) reflects the Scheduling practices and procedures of the

TARIFF. The Parties further acknowledge that in the event that, at any time after the Effective Date and prior to the end of the Contract Term: (i) either one or both of the Parties is no longer a Market Participant; or (ii) the TARIFF or the MISO Business Practices Manuals are no longer in effect or are revised, to the extent that the requirements of Sections 3.2(8) would, if complied with by either Party, achieve a result that would be materially inconsistent with the rights and obligations of the Parties pursuant to the other provisions of this Agreement; or (iii) the MISO market no longer exists, the Parties agree that a new Scheduling mechanism which is consistent with the rights and obligations of the Parties pursuant to this Agreement shall be established including: (A) MP purchasing and taking title to all of the Firm Energy at the Delivery Point and paying for same; and (B) the Parties shall during the Contract Term Schedule the Firm Energy in a manner that would enable MH to satisfy its obligations under this Agreement utilizing MH's resources, (which includes MH's Electrical Generation Facilities), and/or third party purchases, and/or Markets available to MH and the right to utilize any market mechanisms that are available to MH throughout the Contract Term to satisfy its obligations under this Agreement; and make such other necessary amendments to this Agreement to reflect the new Scheduling mechanism, and the Parties agree to direct the Operating Committee to immediately enter into good faith negotiations to establish such new Scheduling mechanism and make such other necessary amendments to this Agreement to reflect the new Scheduling mechanism, failing which the establishment of a new Scheduling mechanism and other amendments to this Agreement shall be determined pursuant to Article XVI on the condition that they are consistent with the rights and obligations of the Parties under this Agreement prior to the revision.

(11) The Parties further acknowledge that in the event that, at any time after the Effective Date and prior to the end of the Contract Term: (i) either one or both of the Parties is no longer a Market Participant; or (ii) the MISO market no

longer exists; and the Parties are participants in different Centrally Operated Markets or one or both of the Parties is not a participant in a Centrally Operated Market, the Parties agree that the "must take" provisions of this Agreement applicable to the Firm Energy shall no longer apply and the Parties shall mutually agree on what quantity, if any, of Firm Energy that MH shall be required to sell to MP and MP shall be required to purchase from MH, but that the "must take" provisions of this Agreement shall continue to apply to all of the Firm Energy if the Parties are participants in the same Centrally Operated Market.

(12) The Parties further acknowledge and agree that in the event that, at any time after the Effective Date and prior to the end of the Contract Term either one or both of the Parties is no longer a Market Participant and one Party is a participant in a Centrally Operated Market that is different from the Centrally Operated Market in which the other Party participates: (i) where one Party is still a participant in the MISO market, the Party that is no longer a participant in the MISO market shall pay all Seams Costs incurred by the Parties in respect of the sale and purchase and delivery of the Firm Energy; and (ii) where neither Party is a participant in the MISO market the Seams Costs incurred by the Parties in respect of the sale and purchase and delivery of the Firm Energy shall be accounted for and allocated between the Parties in an equitable and fair manner taking into account all of the circumstances associated with the Parties incurring such costs.

(13) The Parties further acknowledge that in the event that, at any time after the Effective Date and prior to the end of the Contract Term: (i) either one or both of the Parties is no longer a Market Participant; or (ii) the TARIFF or the Market Business Practices Manuals are no longer in effect or are substantially revised; or (iii) the MISO market no longer exists, the Operating Committee will meet, consult in good faith, and consistent with Section 9.1(3)(d), make

recommendations to the Parties about what amendments or revisions to the Agreement (if any) would be appropriate to address one or both Parties not being a Market Participant, the TARIFF changes or the end of the MISO market. The Operating Committee shall also keep a record of changes to the TARIFF that could impact on the scope and meaning of the Agreement and consistent with Section 9.1(3) make recommendations to the Parties about what amendments or revisions to the Agreement (if any) would be appropriate to address the TARIFF changes.

(14) Capitalized terms used in this Section 3.2 and not otherwise defined in this Agreement shall have the meanings prescribed in the TARIFF or the MISO Business Practices Manual for Definitions.

3.3 Transmission System Operations

The Parties acknowledge that, as of the Effective Date, their respective Transmission Providers operate their transmission systems pursuant to the provisions of an OATT. Nothing in this Agreement shall obligate either Party or their respective Transmission Providers to maintain an OATT in effect during the Contract Term. Notwithstanding Section 3.1, in the event that either Party's Transmission Provider ceases to maintain an OATT at any time during the Contract Term, that Party agrees that it shall use Commercially Reasonable Effort to obtain sufficient transmission capacity for delivery of the applicable amount of the Firm Energy to/from the Delivery Point, as applicable.

3.4 MH's Energy Curtailments and Decrements

(1) MH shall have the right to curtail, restrict, or reduce the sale and supply of any of the Firm Energy in accordance with any of the following provisions:

(a) during any period(s) of time during the Contract Term, if there is either an: (A) Unavailability of MH's Purchased Power; or (B) all or a portion of MH's Electrical Generation Facilities' capacity is unavailable due to: (i) forced outages of one or more generating unit(s);

or (ii) derates of one or more generating unit(s) caused by low water flow or other reason; or (iii) the unavailability of generation outlet capacity caused by a forced outage or derate of MH's HVDC System; or (iv) scheduled outages of generating unit(s) or MH's HVDC System, to the extent that such scheduled outages are reasonably necessary to avoid equipment damage to facilities or to avoid the deferral of normal or scheduled maintenance beyond that consistent with Good Hydro Utility Practice, and if and to the extent that such Unavailability of MH's Purchased Power or outages or derates, as referenced in any of clauses (i), (ii), (iii) or (iv), cause MH to have insufficient energy to serve MH's Energy Commitments, the Firm Energy may be curtailed, restricted or reduced by MH by the amount, if any, determined after application of the Priority Criteria; or

(b) during any period(s) of time during the Contract Term, if and to the extent a Force Majeure event or circumstance(s) otherwise precludes MH's ability to make available, or to continue to make available, any of the Firm Energy in accordance with this Agreement, then to that extent the Firm Energy, may be curtailed, restricted or reduced by MH by the amount, if any, determined after application of the Priority Criteria; or

(c) if and to the extent necessary to avoid curtailing, restricting or reducing service to MH's End-Use Load, in a manner consistent with and to the extent authorized by "Requirement 6.3 of NERC Standard EOP-002" or its successor requirements.

(2) MH shall have the right to decrement the Minimum Annual Energy Amount, if applicable for a Contract Year, when during that Contract Year:

(a) there is either an: (A) Unavailability of MH's Purchased or Sold Power; or (B) all or a portion of MH's Electrical Generation Facilities capacity is unavailable due to: (i) forced outages of one or more generating unit(s); or (ii) derates of one or more generating unit(s) caused by low water flow or other reason; or (iii) the unavailability of generation outlet capacity caused by a forced outage or derate of MH's HVDC System; or (iv) scheduled outages of generating unit(s) or MH's HVDC System, to the extent that such scheduled outages are reasonably necessary to avoid equipment damage to facilities or to avoid the deferral of normal or scheduled maintenance beyond that consistent with Good Hydro Utility Practice, and if and to the extent that such Unavailability of MH's Purchased or Sold Power or outages or derates, as referenced in any of clauses (i), (ii), (iii) or (iv) cause MH to have insufficient energy to serve MH's Energy Commitments; or

(b) a Force Majeure event or circumstance precludes MH's ability to have energy available to offer to MP in accordance with this Agreement,

(each of the events referred to in (a) and (b) of this Section 3.4(2) is referred to as an "**MH Minimum Annual Energy Decrement Event**"),

by the amount, if any, determined in accordance with the provisions of Section 3.10(a). For greater certainty, a MH Minimum Annual Energy Decrement Event can occur and continue only during a period of time during the Contract Term when MH has not offered energy to MP pursuant to this Agreement but can not occur during a period of time for which MH has offered energy to MP in accordance with this Agreement. The Parties also acknowledge and agree that any Firm Energy amount that is offered by MH and curtailed pursuant to Section 3.4(1) shall, notwithstanding such curtailment, be credited to MH as part of the Minimum Annual Energy Amount, if applicable, for a Contract Year, that MH was to have offered and made available during the applicable Contract Year, in accordance with Section 2.1.

(3) In the event of the exercise by MH of the right pursuant to Section 3.4(1) to curtail, restrict or reduce any of the Firm Energy, MH shall:

(a) subject to Section 3.4(3)(c) exercise that right only for an amount and for the applicable time period(s), after application of the Priority Criteria, that MH determines is necessary to respond to the circumstance giving rise to this right to curtail, restrict or reduce any of the Firm Energy; and

(b) exercise Good Hydro Utility Practice to overcome the circumstances giving rise to this right, provided however that MP hereby acknowledges and agrees that the exercise of Good Hydro Utility Practice would not obligate MH to make additional purchases of energy from a third party and/or the Markets.

(4) In the event MH curtails, restricts, or reduces the supply of any of the Firm Energy that has already been accepted into the MISO market or cleared the Day-Ahead Energy and Operating Reserve Market, as applicable ("**MH's Curtailment of Cleared Firm Energy**"), MH shall be responsible for any Market Settlement Amounts charged to MP that were directly related to the curtailment, restriction or reduction in the supply of the Firm Energy due to MH's Curtailment of Cleared Firm Energy under the applicable OATT and/or TARIFF.

3.5 Curtailment Priority Criteria

In the event of the exercise by MH of the right granted pursuant to Section 3.4(1) to curtail, restrict or reduce any of the Firm Energy, then the following priority criteria (the "**Priority Criteria**") shall be used by MH to determine the amount of any of the Firm Energy for the applicable time period(s) that shall be subject to curtailment, restriction or reduction, if applicable, for a Contract Year:

(a) MH's End-Use Load shall have priority over all other power and energy sales of MH;

(b) any power and/or energy sale by MH that is associated with planning capacity and is not part of MH's End Use Load shall take priority over all other power and energy sales of MH, except for MH's End-Use Load;

(c) all of MH's Firm LD Energy Sales and MH's Firm Energy Sales shall take priority over all other power and/or energy sales of MH, except for those referred to in categories (a) and (b) above;

(d) all other power and/or energy sales by MH except for those referred to in categories (a), (b) and (c) above shall have the lowest priority; and

(e) in the event that more than one power and/or energy sale of the same types referred to in categories (b), and (c) of this Section 3.5 exists, curtailment with respect to such power or energy sales within that category shall be determined on a pro rata basis.

The Parties acknowledge that the purchase and sale of the Firm Energy pursuant to this Agreement is part of Section 3.5(c).

3.6 Option to Continue Deliveries

MP acknowledges and agrees that: (a) no provision in this Agreement requires MH to implement the right granted pursuant to Sections 3.4(1) to curtail, restrict or reduce the Firm Energy; (b) MH retains the right to supply the applicable amount of the Firm Energy, under conditions which give rise to the right to curtail, restrict or reduce the applicable amount of the Firm Energy under Section 3.4(1), from any of MH's Electrical Generation Facilities, third party purchases, Markets or market mechanisms available to MH, during any period of time, for which this right exists, provided MH does so for the entire period of time during which it had the right pursuant to Section 3.4(1) to curtail, restrict or reduce the applicable amount of the Firm Energy to be supplied and does not selectively assert the right to provide the applicable amount of the Firm Energy in only some, but not all, hours of the period of time when it would otherwise have the right to curtail, restrict or reduce the applicable amount of the Firm Energy; and (c) in conjunction with the implementation of the right granted pursuant to Section 3.4(1) to curtail, restrict or reduce any of the applicable amount of the Firm Energy and MH's covenant to do so in accordance with the provisions of Section 3.5

and the Priority Criteria referenced therein, MH shall have the right, but not the obligation, to curtail, restrict or reduce one type of its power and/or energy sales and not another type of its power and/or energy sales even though under the Priority Criteria the power and/or energy sale that was curtailed had a higher priority. The exercise of the right under Section 3.6(c) is subject to MH continuing to provide service, through purchases made from third parties, Markets and/or Market mechanisms available to MH, to the power and/or energy sale that was not curtailed despite having a lower priority. For greater certainty the exercise of the right under Section 3.6(c) does not restrict or limit MH's right granted pursuant to Section 3.4(1) to curtail, restrict or reduce the applicable amount of the Firm Energy.

3.7 <u>Transmission Provider Curtailments and Decrements</u>

(1) In the event that the Transmission Provider(s) of MH and/or MP reduces or curtails the Firm Transmission Service designated, allocated or required for the delivery of the Firm Energy, the Firm Energy that is to be supplied by MH and received by MP shall be curtailed, restricted or reduced in accordance with the provisions of that Transmission Provider's OATT. The Parties also agree that where MH has been unable to obtain sufficient quantities of Net Scheduled Interchange including "ramp capability" to have its offer for the energy clear the Day-Ahead Energy and Operating Reserve Market, the quantity of the Firm Energy that did not clear the said market shall be deemed to have been curtailed pursuant to this Section 3.7(1).

(2) Subject to Section 19.3, in the event MH, MH's Transmission Provider or MP's Transmission Provider ceases to have an OATT, curtailment or reduction of Firm Energy Schedules hereunder in order to maintain the reliable operation of the interconnected AC transmission system shall be implemented exclusively in accordance with this Section. Curtailment of energy deliveries under this Section to accommodate such events shall be implemented as follows, in the order specified, until the required amount of loading relief has been obtained: (a) all transmission service or transactions that are lower than Firm Transmission Service, and which contribute to the condition requiring

curtailment, shall be curtailed first; (b) the applicable Party shall use Commercially Reasonable Efforts to cause the curtailing Person to redispatch its generation system to continue the Schedules hereunder consistent with producing the desired loading mitigation upon the congested facility(s); and (c) to the extent all transactions identified in clause (a) of this Section 3.7(2) are curtailed and system redispatch is not sufficient to produce the necessary mitigation that would avoid curtailment of the Schedules under this Agreement, the transaction curtailment priority used by MH relative to all uses of such AC transmission system at the time shall be implemented in a comparable and non-discriminatory manner.

(3) In the event that the Transmission Provider(s) of MH and/or MP reduces or curtails the Firm Transmission Service designated, allocated or required for the delivery of the energy offered by MH to MP pursuant to this Agreement ("**Transmission Minimum Annual Energy Decrement Event**"), the Minimum Annual Energy Amount, if applicable for a Contract Year, shall be decremented by the amount determined in accordance with Section 3.10(b), during the period of such Transmission Minimum Annual Energy Decrement Event. For greater certainty, a Transmission Minimum Annual Energy Decrement Event can occur and continue only during a period of time when MH has not offered energy to MP pursuant to this Agreement but can not occur during a period of time for which MH has offered energy to MP in accordance with this Agreement. The Parties also acknowledge and agree that any Firm Energy amount that is offered by MH and curtailed pursuant to Section 3.7(1) shall, notwithstanding such curtailment, be credited to MH as part of the Minimum Annual Energy Amount, if applicable, for a Contract Year, that MH was to have offered and made available during the applicable Contract Year, in accordance with Section 2.1.

3.8 MP's Curtailments and Decrements

(1) MP shall have the right to refuse to accept and purchase such quantity of the

energy offered by MH pursuant to this Agreement to the extent a Force Majeure event or circumstance(s) precludes MP's ability to accept such quantity of the energy that is offered by MH pursuant to this Agreement.

(2) In the event MP refuses to accept any of the Firm Energy, pursuant to Section 3.8(1), that has already been accepted into the MISO market or cleared the Day-Ahead Energy and Operating Reserve Market, as applicable ("**MP's Curtailment of MH's Cleared Energy**"), MP shall be responsible for any Market Settlement Amounts charged to MH that were directly related to the curtailment, restriction or reduction in the supply of the Firm Energy due to MP's Curtailment of MH's Cleared Energy under the applicable OATT and/or TARIFF.

(3) The Minimum Annual Energy Amount, if applicable for a Contract Year, shall be decremented when a Force Majeure event or circumstance would preclude MP from accepting energy from MH under this Agreement ("**MP Minimum Annual Energy Decrement Event**"), during the period of such MP Minimum Annual Energy Decrement Event, by the amount determined in accordance with Section 3.10(c). For greater certainty, a MP Minimum Annual Energy Decrement Event: (i) can occur and continue only during a period of time when MH has not offered energy to MP pursuant to this Agreement; (ii) will occur if MH has not offered energy to MP, if MP has advised MH that a Force Majeure event or circumstance, in accordance with the provisions of this Agreement, would prevent MP from accepting energy from MH under this Agreement; and (iii) can not occur during a period of time for which MH has offered energy to MP in accordance with this Agreement. The Parties also acknowledge and agree that any Firm Energy amount that is offered by MH and is curtailed pursuant to Section 3.8(1) shall, notwithstanding such curtailment, be credited to MH as part of the Minimum Annual Energy Amount, if applicable, for a Contract Year, that MH was to have offered and made available during the applicable Contract Year, in accordance with Section 2.1.

3.9 Curtailment and/or Decrementing Notices

Each Party shall provide as much notice as practicable to the other Party regarding: (i) the curtailment, restriction or reduction or refusal of the supply or acceptance, as applicable, of the Firm Energy and/or the energy offered by MH, as applicable; and/or (ii) the decrementing of the Minimum Annual Energy Amount, if applicable for a Contract Year, in each instance pursuant to the applicable subsections of Sections 3.4, 3.7 and 3.8 and Article XIII. Such notices shall include the anticipated duration and amount of: (a) the curtailment, restriction, or reduction or refusal of the supply or acceptance, as applicable, of the Firm Energy and where practicable, daily updates; and/or (b) the decrementing of the Minimum Annual Energy Amount, if applicable for a Contract Year, and where practicable daily updates.

3.10 Minimum Annual Energy

The Minimum Annual Energy Amount, if applicable for a Contract Year, shall be decremented:

(a) for each MH Minimum Annual Energy Decrement Event that occurs during the applicable Contract Year, that MH has determined it will exercise its right to decrement the Minimum Annual Energy Amount, by the amount determined from multiplying: (i) the duration (in hours) of the applicable MH Minimum Annual Energy Decrement Event; and (ii) [**TRADE SECRET DATA EXCISED**];

(b) for each Transmission Minimum Annual Energy Decrement Event that occurs during the applicable Contract Year, by the amount determined from multiplying: (i) the duration (in hours) of the Transmission Minimum Annual Energy Decrement Event; and (ii) [**TRADE SECRET DATA EXCISED**]; and

(c) for each MP Minimum Annual Energy Decrement Event that occurs during the applicable Contract Year, by the amount determined from multiplying (i) the duration (in hours) of the MP Minimum Annual Energy Decrement Event; and (ii) [**TRADE SECRET DATA EXCISED**].

3.11 <u>Contingency Reserves, Contingency Reserves Emergency Energy, and Emergency Energy</u>

The Parties acknowledge and agree that:

(a) Contingency Reserves and Contingency Reserves Emergency Energy made available by MH to MISO during the Contract Term pursuant to MH's NERC Contingency Reserve obligations shall not be considered to be Firm Energy;

(b) Emergency Energy made available by MH to MISO during the Contract Term shall not be considered to be Firm Energy;

(c) MH shall have the right to deliver during the Contract Term Contingency Reserves, Contingency Reserves Emergency Energy and Emergency Energy using the Transmission Service;

(d) all payments received by MP from a Transmission Provider for Contingency Reserves, Contingency Reserves Emergency Energy and/or Emergency Energy made available to MISO by MH during the Contract Term which are received by MP by virtue of MP's rights in and to the Transmission Service or otherwise shall be remitted by MP to MH in the month following MP's receipt of said payments; and

(e) all costs associated with Contingency Reserves, Contingency Reserves Emergency Energy and/or Emergency Energy charged to MH by MISO which are attributable to MP during the Contract Term shall be billed to MP by MH and shall be paid by MP in the month following MP's receipt of the billing for said costs to the extent MH is not compensated by MISO for the said costs.

ARTICLE IV
ENERGY PRICING

4.1 <u>Energy Pricing</u>

[**TRADE SECRET DATA EXCISED**]

ARTICLE V

BILLING AND PAYMENT

5.1 Dollar Amounts

All dollar amounts set forth in this Agreement, monetary transactions, accounting and cost calculations between MH and MP shall be determined and stated in U.S. Dollars.

5.2 Payment in U.S. Dollars

Payment of all invoices pursuant to this Agreement shall be made in U.S. Dollars.

5.3 Method of Payment of Invoices

Payment of all invoices pursuant to this Agreement shall be made by the Party required to make the payment to the Party entitled to receive the payment by electronic bank transfer or by other mutually agreeable method(s), to the bank designated in Appendix C attached hereto. A Party may change the designation of the bank set out in Appendix C by notice to the other Party in accordance with Section 19.1 hereof. Payment shall be deemed to be made when received by the bank designated in Appendix C.

5.4 Rendering Invoices

Unless otherwise specifically agreed upon by the Parties, the calendar month shall be the standard billing period for all invoices rendered under this Agreement. As soon as practicable after the end of each calendar month, each Party shall render to the other Party an invoice for the payment obligations, if any, incurred hereunder during the preceding month.

5.5 Payment Amounts

(1) Subject to Section 5.5(2), the amount payable by MP to MH for each month during the Contract Term shall be determined as follows:

(a) the sum of the amount determined for each applicable hour that a quantity was Scheduled for that month determined as follows:

(i) [**TRADE SECRET DATA EXCISED**]; less

(b) the sum of the amount determined for each applicable hour that a quantity of Firm Energy that had been Scheduled during any day for that month was curtailed, restricted or reduced pursuant to Sections 3.4, 3.7 or 3.8 or Article XIII as follows:

(i) [**TRADE SECRET DATA EXCISED**]; plus

(c) the amount of all payments received by MP during that month from a Transmission Provider for Contingency Reserves, Contingency Reserves Emergency Energy and/or Emergency Energy made available to the MISO by MH during the Contract Term which are received by MP by virtue of MP's rights in and to the Transmission Service or otherwise as provided in Section 3.11(d); plus

(d) the amount of all costs associated with Contingency Reserves, Contingency Reserves Emergency Energy and/or Emergency Energy charged to MH by the MISO during that month which are attributable to MP during the Contract Term (to the extent MH is not compensated by the MISO for the said costs) as provided in Section 3.11(e); plus

(e) any costs and expenses associated with the supply and receipt of the Firm Energy under the applicable OATT that were: (i) billed to and paid by MH during that month; or (ii) billed to MH during a prior month and paid by MH during that month, but were amounts that were required to be paid by MP pursuant to Sections 3.2(7); less

(f) any costs and expenses associated with the supply and receipt of the Firm Energy under the applicable OATT that were: (i) billed to and paid by MP during that month; or (ii) billed to MP during a prior month and paid by MH during that month, but were amounts that were required to be paid by MH pursuant to Section 3.2(7); plus

(g) any Market Settlement Amounts: (i) charged to and paid by MH during that month; or (ii) charged to MH during a prior month and paid by MH during that month, that were directly related to the curtailment, restriction or reduction in supply of Firm Energy due to MP's Curtailment of MH's Cleared Firm Energy under the applicable OATT and/or the TARIFF but were amounts that were required to be paid by MP pursuant to Section 3.8(2); less

(h) any Market Settlement Amounts: (i) charged to and paid by MP during that month; or (ii) charged to MP during a prior month and paid by MP during that month, that were directly related to the curtailment, restriction or reduction in supply of Firm Energy due to MH's Curtailment of Cleared Firm Energy under the applicable OATT and/or the TARIFF but were amounts that were required to be paid by MH pursuant to Section 3.4(4).

(2) [**TRADE SECRET DATA EXCISED**]

5.6 <u>Payment Date</u>

Unless otherwise agreed by the Parties, all invoices under this Agreement shall be due and payable in accordance with each Party's invoice instructions on or before the third (3rd) Business Day after receipt of the invoice. Any amounts not paid by the due date shall be deemed delinquent and shall accrue interest at the Interest Rate and such interest shall be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

5.7 <u>Estimates</u>

In the event that not all of the information necessary for the preparation of the monthly invoice is known in time for the preparation of the monthly invoice, estimates may be used on the monthly invoice to be followed with an adjustment on a future invoice to reflect actual charges as soon as they are known. In the event that the amount paid or payable on any invoice or invoices delivered pursuant to this Agreement is based, in whole or in part, upon third party invoices and the third party subsequently adjusts their invoice, MH shall charge or credit MP for the change in such third party invoice within sixty (60) Business Days of MH's receipt of such adjusted third party invoice.

5.8 <u>Billing Adjustments and Disputes</u>

A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice rendered under this Agreement within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the invoice, as invoiced, shall be required to be made when due. Notice of the dispute shall be given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Upon resolution of the dispute, any required payment or reimbursement shall be made within ten (10) Business Days after the date of such resolution, along with interest accrued at the Interest Rate from and including the date the payment was originally to be made by the disputing Party to but excluding the date the payment or reimbursement is paid. Inadvertent overpayments shall be deducted by the Party receiving such overpayment from subsequent weekly invoices rendered by such Party. Any dispute with respect to an invoice or adjustment is waived unless the other Party is notified in accordance with this Section 5.8 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made.

5.9 Netting

(1) The billing departments of each of the Parties shall exchange settlement data under each of the MH/MP Agreements. A netting computation of the amount that each Party has determined is due and owing under each of the MH/MP Agreements for the applicable billing period shall be performed by each of the Parties by the third (3) Business Day following the last day of each month. If the Parties are in agreement as to the net amount owing by a Party under the MH/MP Agreements, that net amount shall be paid by that Party by the date referenced in Section 5.6. If the net amount agreed upon is not paid by that date, or if the Parties are unable to agree on the net amount to be paid, all of the provisions of each of the MH/MP Agreements, including the billing and payment provisions shall continue to govern the payment obligations of each Party, and all amounts due under this Agreement shall be paid in full on the date payment is required to be made under this Agreement.

(2) The payment by a Defaulting Party of any amounts due under each of the MH/MP Agreements shall be a condition precedent to the payment of any amounts due by the Non-defaulting Party to the Defaulting Party under any of the MH/MP Agreements.

5.10 Payment in Full

If the Parties subsequently mutually agree not to net payments pursuant to Section 5.9 or only one Party owes a debt or obligation to the other during the applicable billing period, including, but not limited to, any interest, and payments or credits, that Party shall pay such sum in full when due.

5.11 Impact of Performance Assurance

Except in connection with a termination in accordance with Article XVII in which circumstances the Party benefiting from the Performance Assurance notifies the other Party in writing, amounts invoiced pursuant to this Article V shall not take into account or include any Performance Assurance which may be in effect to secure a Party's performance under this Agreement.

5.12 Accounting and Billing Procedures

The Operating Committee may make and implement decisions regarding the creation and revision, from time to time, of accounting and billing procedures necessary to implement the terms and conditions of this Agreement, including the provisions of Article V.

5.13 Preliminary Billing Information

The Parties shall exchange preliminary billing information in accordance with the accounting and billing procedures established by the Operating Committee.

ARTICLE VI
GOVERNMENTAL CHARGES

6.1 Governmental Charges

Each Party shall be solely responsible for and shall pay or cause to be paid all Governmental Charges imposed on that Party in respect of any matters related to this Agreement. In the event MH is required by law or regulation to remit or pay Governmental Charges that are MP's responsibility hereunder, MP shall promptly reimburse MH for such Governmental Charges. In the event MP is required by law or regulation to remit or pay Governmental Charges that are MH's responsibility hereunder, MH shall promptly reimburse MP for such Governmental Charges. For greater certainty, the Parties agree and acknowledge that, as of the Effective Date, MP is a non-resident, non-registrant not carrying on business in Canada in respect of all supplies hereunder for Canadian federal goods and services tax purposes.

6.2 Assistance

Each Party shall provide reasonable assistance to the other Party in connection with and for the purpose of enabling due compliance with Governmental Charges and all associated information, documentation and reporting obligations. Each Party shall provide to the other and to a Governmental Authority having jurisdiction such forms, returns, reports, documents, elections, written declarations, certificates, etc. as the other Party may reasonably request, including without limitation any documentation that may be required to substantiate any available exemptions or relief from Governmental Charges.

ARTICLE VII
METERING

7.1 Metering

All applicable matters relating to the metering of the Firm Energy shall be determined in accordance with the applicable provisions of agreements between the Parties' Transmission Providers relating to revenue metering, and the application of the provisions of such agreements shall, if necessary, be referred to the Operating Committee.

ARTICLE VIII
ENVIRONMENTAL ATTRIBUTES

8.1 <u>Environmental Attributes of Firm Energy</u>

(1) The Parties acknowledge and agree that MH shall allocate and transfer to MP that amount of Environmental Attributes (the "[**TRADE SECRET DATA EXCISED**] **Environmental Attributes**") determined by MH, only for the purposes of allocating and transferring Environmental Attributes pursuant to Section 8.2 and Section 8.4, to be from that portion of the MWh of Firm Energy that was: (a) Supplied Energy; and (b) allocated or determined by MH, only for the purpose of allocating and transferring Environmental Attributes, to be sourced from [**TRADE SECRET DATA EXCISED**].

(2) The Parties acknowledge and agree that for environmental reporting purposes, the Environmental Attributes of that component of the Firm Energy that: (a) is Supplied Energy; and (b) is not allocated or determined by MH in accordance to be sourced from [**TRADE SECRET DATA EXCISED**] in accordance with this Article XIII, shall be reported, as being electrical energy which is sourced from the [**TRADE SECRET DATA EXCISED**] MH's Energy Resources stipulated by MH in accordance with this Article VIII.

(3) The Parties further acknowledge and agree that for environmental reporting purposes, the Environmental Attributes of that component of the Firm Energy, that is not Supplied Energy, is electrical energy which is not sourced from any specific generation type or resource and has Environmental Attributes equivalent to energy that is associated with the applicable market in which the majority of MP's load is physically situated and shall be reported by each of the Parties, in that manner, in any reports that are filed by each of the Parties in respect of the purchase and sale of the Firm Energy pursuant to this Agreement.

(4) MH shall not be obligated to manage the supply of the Firm Energy in any particular manner, nor does this Agreement restrict or limit MH to any specific type(s) of generating resources to be used to supply the Firm Energy (including energy obtained from third party purchases and/or the Markets available to MH, regardless of the generation type used by the third party or

which generating resources may have been attributable to the energy accessed through the Markets), nor shall any provision in this Agreement constitute a representation or warranty by MH that the Firm Energy is supplied from a particular generating resource, including renewable resources.

(5) The Parties acknowledge and agree that the consideration for the [**TRADE SECRET DATA EXCISED**] Environmental Attributes is included in the price for the Firm Energy.

(6) Without limiting the reporting requirements referred to in Section 8.1(2), the Parties further acknowledge and agree that MH has retained all Environmental Attributes for the Firm Energy allocated or determined by MH for the purposes of this Article to be sourced from those MH's Energy Resources that are [**TRADE SECRET DATA EXCISED**], as referred to in this Article VIII. For greater certainty [**TRADE SECRET DATA EXCISED**] is not included as part of MH's Energy Resources and in the event that the Environmental Attributes of energy from [**TRADE SECRET DATA EXCISED**], including any form of credits are, notwithstanding the provisions of this Article VIII, received by MP, MP agrees: (i) to assign and transfer the said Environmental Attributes of [**TRADE SECRET DATA EXCISED**] to MH, in such manner as MH may request, acting reasonably; (ii) to cooperate with MH in making any required filing with any Governmental Authority or other Person in respect of the assignment and transfer referred to in (i); and (iii) in the event applicable laws or rules governing any applicable Market prevents or restricts the assignment or transfer referred to in (i), MP agrees to [**TRADE SECRET DATA EXCISED**].

(7) The Parties acknowledge and agree that MH shall be entitled to revise or amend Appendix B, with reasonable notice to MP, to [**TRADE SECRET DATA EXCISED**].

8.2 <u>Calculation of Environmental Attributes</u>

(1) MH shall calculate the Environmental Attributes of the Supplied Energy purchased by MP, for the purposes of this Article VIII during the Contract Term in the following manner:

(a) [**TRADE SECRET DATA EXCISED**]

8.3 Reporting of Environmental Attributes

(1) On or before March 31st of each calendar year, MH shall provide MP with a report, for each preceding calendar year or applicable portion thereof, during the Contract Term, in accordance with the procedures established by MH for such reporting, that identifies the MWh of the Firm Energy that was supplied from MH's Energy Resources and the MWh of the Firm Energy that is not Supplied Energy and the Environmental Attributes of each of MH's Energy Resources.

(2) The Parties acknowledge and agree that the report referred to above shall be used by MH and MP when reporting the Environmental Attributes of the Firm Energy.

8.4 Transfer of Environmental Attributes

(1) MH shall transfer to MP the [**TRADE SECRET DATA EXCISED**] Environmental Attributes applicable for each calendar year during the Contract Term, on or before March 31st of the subsequent calendar year.

(2) For MH's Energy Resources that [**TRADE SECRET DATA EXCISED**] are registered by MH on a system used to track and transfer Environmental Attributes and used by MH to transfer [**TRADE SECRET DATA EXCISED**] (the "**Transfer System**"), MP shall receive the transfer of the applicable amount of [**TRADE SECRET DATA EXCISED**] Environmental Attributes through the Transfer System. MH's transfer through the Transfer System will be on the condition that MP complies, at its own expense, with the Transfer System requirements concerning the acceptance of the transferred [**TRADE

SECRET DATA EXCISED] Environmental Attributes.

(3) If any of MH's Energy Resources [**TRADE SECRET DATA EXCISED**] are not registered by MH on a Transfer System, MP shall receive the transfer of the applicable amount of the [**TRADE SECRET DATA EXCISED**] Environmental Attributes from MH, by MH providing a transfer substantially in the form used by MH generally for the transfer of Environmental Attributes.

(4) Subject to Section 8.4(5), MH shall be responsible for all costs required for MH to be a member of, access and utilize the Transfer System for the recording, transfer and receipt of the [**TRADE SECRET DATA EXCISED**] Environmental Attributes.

(5) MP shall be responsible for all costs required for MP to be a member, access and utilize the Transfer System for the recording, transfer and receipt of the [**TRADE SECRET DATA EXCISED**] Environmental Attributes.

(6) No actions shall be required to be undertaken by MH in respect of the transfer to MP of the [**TRADE SECRET DATA EXCISED**] Environmental Attributes, except as expressly provided herein

8.5 Use

MP may use any and all of the [**TRADE SECRET DATA EXCISED**] Environmental Attributes at its sole discretion and for MP's sole benefit, including without limitation the re-sale of the [**TRADE SECRET DATA EXCISED**] Environmental Attributes.

8.6 Rights Conferred by Law

In the event that the [**TRADE SECRET DATA EXCISED**] Environmental Attributes are conferred by statute or other legal instrument to MH, MH shall transfer the [**TRADE SECRET DATA EXCISED**] Environmental Attributes to MP in accordance with MH's procedures and the terms of this Agreement provided that MH has the legal authority for so doing. If MH does not have the legal authority to transfer the [**TRADE SECRET DATA EXCISED**] Environmental Attributes to MP, then MH shall use Commercially Reasonable Efforts to obtain such legal authority.

TRADE SECRET DATA EXCISED

8.7 MP Qualification

To the extent allowed by applicable law, MP may have the [**TRADE SECRET DATA EXCISED**] Environmental Attributes qualified and recognized as environmental credits or offsets, if any. MH shall cooperate in such qualification and recognition in accordance with the procedures that it uses or applies generally to the qualification and recognition of [**TRADE SECRET DATA EXCISED**] Environmental Attributes. Without limiting the generality of Section 8.9 and Section 18.1, neither Party makes any representation or warranty with respect to any future action or failure to act, or approval or failure to approve, by any Governmental Authority or any other third Person in respect of the allocation and transfer of the [**TRADE SECRET DATA EXCISED**] Environmental Attributes.

8.8 [TRADE SECRET DATA EXCISED]

[**TRADE SECRET DATA EXCISED**]

8.9 Disclaimer

WITH RESPECT TO THE [**TRADE SECRET DATA EXCISED**] ENVIRONMENTAL ATTRIBUTES TO BE TRANSFERRED UNDER THIS AGREEMENT, EXCEPT AS EXPRESSLY SET FORTH IN THIS AGREEMENT, MH EXPRESSLY DISCLAIMS ANY OTHER REPRESENTATIONS OR WARRANTIES, WHETHER WRITTEN OR ORAL, AND WHETHER EXPRESS OR IMPLIED. WITHOUT LIMITING THE GENERALITY OF THE FOREGOING, MH MAKES NO REPRESENTATION OR WARRANTY HEREUNDER REGARDING THE SUITABILITY OR LIKELIHOOD OF THE [**TRADE SECRET DATA EXCISED**] ENVIRONMENTAL ATTRIBUTES TO MEET OR QUALIFY UNDER ANY VOLUNTARY OR MANDATORY PROGRAM PERTAINING TO THE GENERATION OF “GREEN” OR CARBON NEUTRAL ELECTRIC POWER OR REGARDING ANY CREATION OF A FEDERAL, STATE OR LOCAL MANDATORY OR VOLUNTARY RENEWABLE PORTFOLIO STANDARD OR CARBON OFFSET OR ALLOWANCE TRADING PROGRAM UNDER WHICH

THE [**TRADE SECRET DATA EXCISED**] ENVIRONMENTAL ATTRIBUTES COULD BE SOLD, TRANSFERRED OR USED FOR COMPLIANCE.

ARTICLE IX
OPERATING COMMITTEE

9.1 Operating Committee

(1) A committee (the "**Operating Committee**") is hereby constituted consisting of the Division Manager of Power Sales & Operations for MH or a duly authorized delegate from MH, and the Vice-President Strategy and Planning for MP or a duly authorized delegate from MP. Both MH and MP shall have one vote on the Operating Committee, and all decisions of the Operating Committee must be unanimous to be effective.

(2) The Operating Committee shall meet at the written request of either of its members within ten (10) Business Days of receipt of such request. Written minutes shall be kept of all meetings and decisions and copies of such minutes shall be distributed to the Operating Committee members and the Parties within five (5) Business Days after each meeting.

(3) The Operating Committee may:

(a) make and implement decisions regarding the creation and revision, from time to time, of accounting and billing procedures necessary to implement the terms and conditions of this Agreement in accordance with Sections 5.11 and 5.12;

(b) make and implement decisions and procedures regarding Scheduling from time to time as necessary to implement the terms and conditions of this Agreement in accordance with Section 3.2;

(c) make and implement decisions and procedures regarding the sale and purchase and delivery and receipt of MH's Real Time Energy in accordance with Section 3.2(9);

(d) make and implement decisions for operating procedures for the conduct of meetings and the recording of minutes;

(e) make recommendations to the Parties concerning amendment and revision of this Agreement;

(f) perform any other obligations expressly provided for in this Agreement to be performed by the Operating Committee and any other matters as the Parties may agree from time to time;

(g) attempt to resolve any controversy, claim or dispute prior to referring such matters to the Executive Officers of MP and MH for resolution in accordance with Section 16.1 and the form of notices being provided by the Parties pursuant to the provisions of this Agreement; and

(h) make and implement decisions concerning Section 19.1 and the form of notices being provided by the Parties pursuant to the provisions of this Agreement,

provided that the Operating Committee shall not have authority to modify the terms and conditions of this Agreement.

ARTICLE X

REPRESENTATIONS, WARRANTIES AND COVENANTS

10.1 <u>General and US Bankruptcy Representations and Warranties</u>

(1) Each Party makes the following representations and warranties to the other Party, which representations and warranties will be deemed to be repeated, if applicable, by each Party throughout the Contract Term:

(a) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(b) subject to Article XII, it has all regulatory authorizations necessary for it to legally perform its obligations under this Agreement;

(c) subject to Article XII, the execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

(d) this Agreement and each other document executed and delivered by it in accordance with this Agreement constitutes its legally valid and binding obligation, enforceable against it in accordance with its terms, subject to any equitable defences;

(e) it is a Market Participant as of the date of the execution of this Agreement;

(f) it or its Credit Support Provider, if any, is not bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it or its Credit Support Provider, if any, being or becoming bankrupt;

(g) there is not pending or, to its knowledge, threatened against it or any of its Affiliates or its Credit Support Provider, if any, any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement;

(h) it is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing and understanding the merits, and understands and accepts, the terms, conditions and risks of this Agreement. It is also capable of assuming, and assumes, the risks of this Agreement. Information and explanations related to the terms and conditions of this Agreement will not be considered advice or a recommendation to enter into this Agreement. No communication (written or oral) received from the other Party will be deemed to be an assurance or guarantee as to the expected results of this Agreement, unless such communication is expressly stated in writing to be a "guarantee" and is signed by the Party providing the statement;

(i) it has entered into this Agreement in connection with the conduct of its business and it has, subject to the provisions of this Agreement, the capacity or ability to make available or take delivery of (as applicable) all of the Firm Energy;

(j) the other Party is not acting as a fiduciary for or an adviser to it in respect of this Agreement;

(k) this Agreement constitutes a "master netting agreement" and all transactions pursuant to it constitute "forward contracts" within the meaning of the United States Bankruptcy Code ("**Bankruptcy Code**") or a "swap agreement" within the meaning of the Bankruptcy Code;

(l) it is a "forward contract merchant" within the meaning of the Bankruptcy Code with respect to any transactions under this Agreement that constitute "forward contracts" and a "swap participant" with respect to any transactions under this Agreement that constitute "swap agreements", all within the meaning of the Bankruptcy Code;

(m) all payments made or to be made by one Party to the other Party pursuant to this Agreement constitute "settlement payments" within the meaning of the Bankruptcy Code;

(n) all transfers of Performance Assurance by one Party to the other Party under this Agreement constitute "margin payments" within the meaning of the Bankruptcy Code;

(o) it is a "master netting agreement participant" within the meaning of the Bankruptcy Code;

(p) certain provisions of this Agreement grant each Party the contractual right to "cause the liquidation, termination, or acceleration" of this Agreement or the transactions under this Agreement within the meaning of Sections 556, 560 and 561 of the Bankruptcy Code, as they may be amended, superseded or replaced from time to time;

(q) it intends and agrees that, if it goes into bankruptcy, the other Party shall be entitled to exercise its rights and remedies under this Agreement in accordance with the safe harbour provisions of the

Bankruptcy Code set forth in, *inter alia*, Sections 362(b)(6), 362(b)(17), 362(b)(27), 362(o), 546(e), 548(d)(2), 556, 560 and 561, as they may be amended, superseded or replaced from time to time;

(r) it is an “eligible contract participant” as defined in Section 1a(12) of the Commodity Exchange Act, as amended, 7 U.S.C. § 1a(12);

(s) it (i) is a producer, processor, or commercial user of, or a merchant handling, the commodity which is the subject of this Agreement, or the products or by products thereof; and (ii) enters into this Agreement solely for purposes related to its business as such;

(t) (i) for the purposes of this Agreement, neither it nor the other Party is a "utility" as such term is used in 11 U.S.C. Section 366; and (ii) it waives and agrees not to assert against the other Party the applicability of the provisions of 11 U.S.C. Section 366 in any bankruptcy proceeding wherein it is a debtor and in any such proceeding, it further waives the right to assert that the other Party is a provider of last resort; and

(u) the Parties acknowledge that all transactions executed under this Agreement, and this Agreement itself, are commercial merchandizing contracts that are not regulated under the Commodity Exchange Act, as amended, 7 U.S.C. Sec. 1, et seq. (the "**Act**") and lawful Commodity Futures Trading Commission ("**CFTC**") regulations promulgated thereunder (“**Regulations**”), as "swaps" as defined in Sec. 1a(47)(A) of the Act but rather all transactions under this Agreement and this Agreement itself are excluded from the term “swap” under Section 1a(47)(B)(ii) of the Act.

(2) MH makes the following additional representations and warranties to MP as of the Effective Date, which representations and warranties will be deemed to be repeated throughout the Contract Term:

(a) no Event of Default with respect to MH and no MH Termination Event has occurred and is continuing; and

(b) no Event of Default with respect to MH and no MH Termination Event would occur as a result of its entering into or performing its obligations under this Agreement.

(3) MP makes the following additional representations and warranties to MH as of the Effective Date, which representations and warranties will be deemed to be repeated throughout the Contract Term:

(a) no Event of Default with respect to MP and no MP Termination Event has occurred and is continuing; and

(b) no Event of Default with respect to MP and no MP Termination Event would occur as a result of its entering into or performing its obligations under this Agreement.

10.2 MH Tax Representations and Warranties

MH makes the following representations and warranties to MP, which representations and warranties will be deemed to be repeated, if applicable, by MH throughout the Contract Term:

(a) it is a foreign person (as that term is used in section 1.6041-4(a)(4) of the United States Treasury Regulations) for United States federal income tax purposes and its U.S. Taxpayer identification number is 98-0126210; and

(b) no part of any payment received or to be received by MH in connection with this Agreement is attributable to a trade or business carried on by it in the United States of America.

10.3 MP Tax Representations

MP makes the following representations and warranties to MH, which representations and warranties will be deemed to be repeated, if applicable, by MP throughout the Contract Term:

(a) it is a "U.S. person" (as that term is used in section 1.1441-4(a) (3) (ii) of the United States Treasury Regulations) for United States federal income tax purposes and its U.S. Taxpayer identification number is 39-0715160; and

(b) no part of any payment received or to be received by MP in connection with this Agreement is attributable to a trade or business carried on by it or in respect of services rendered by it in Canada.

ARTICLE XI
CONFIDENTIALITY

11.1 Confidentiality

The Parties confirm that Confidential Information (as defined in the "Non-Disclosure Agreement") had been disclosed by each Party to the other Party during the course of negotiating this Agreement and acknowledge that the provisions of the Non-Disclosure Agreement governs the disclosure of all such Confidential Information that was disclosed up to the date this Agreement is executed. The Parties (each a "**Discloser**") also recognize that there is a need pursuant to this Agreement for each Party to disclose Confidential Information, after the date this Agreement is executed, to the other Party (each a "**Recipient**") and that the provisions of this Agreement will govern the disclosure of such information not the Non-Disclosure Agreement and the Parties wish to protect the Confidential Information in the following manner and agree as follows:

(a) **"Confidential Information"** shall mean all non-public and confidential information which information is treated by the Discloser and its representatives as confidential and which is conspicuously marked "Confidential" if in written or printed form, or if oral, which is specifically identified as confidential at the time of disclosure and is confirmed in writing to each other party as "Confidential" within five (5) Business Days after disclosure, unless: (i) the information is or becomes publicly known through lawful means; (ii) the information was rightfully in Recipient's possession or part of Recipient's general knowledge prior to the date of this Agreement; or (iii) the information is disclosed to Recipient without confidential restriction by a third party who rightfully possesses the information (without confidential restriction) and did not learn of it, directly or indirectly, from

Recipient.

(b) Except as hereinafter provided, Recipient shall hold all Confidential Information in strict confidence and shall not disclose any Confidential Information to any third party. Recipient shall take all reasonable measures to protect the confidentiality of, and avoid the unauthorized use, disclosure, publication, or dissemination of Confidential Information. Recipient may disclose Confidential Information:

(i) to its directors, officers, employees, members, agents or advisors, including, without limitation, its attorneys, accountants, consultants and financial advisors who need to know such information for the purposes of the transactions contemplated by this Agreement (each a "**Representative**"); and

(ii) to any other third parties, only with the prior written consent of the Discloser.

(c) If the Recipient or its Representatives are required to disclose the Confidential Information by law, regulation, ruling of a governmental agency or by court order, before the Recipient or its Representatives disclose any Confidential Information, the Recipient or its Representatives shall give the Discloser timely written notice (at least 10 Business Days) of the requirement for disclosure and assist the Discloser to secure a protective order to limit disclosure of such Confidential Information only to parties agreeing to be bound by the terms of a confidentiality agreement in a form and content satisfactory to the Discloser, acting reasonably. Recipient shall cooperate reasonably in any such efforts to secure a protective order; provided, however, Recipient shall not be required to take, or refrain from taking, any action if it would cause Recipient or its Representatives to be in violation of the terms of a required disclosure described in this Section 11.1(c).

(d) Notwithstanding the foregoing, the Parties acknowledge that if MP files this Agreement with the Minnesota Public Utilities Commission, MP agrees to seek protection of the Confidential Information in this Agreement under the Minnesota Public Utilities Commission's Minnesota Rule 7829.0500. The Parties will cooperate reasonably to prepare a public version of this Agreement for inclusion in the public record at the Minnesota Public Utilities Commission. The Parties agree that the public version of this Agreement will redact only such Confidential Information that properly constitutes proprietary information, trade secrets, or other privileged information as defined by applicable Minnesota laws.

(e) Recipient shall be liable for any use or disclosure of Confidential Information by its Representatives, which is not in compliance with the obligations imposed upon the Recipient pursuant to this Agreement.

(f) All rights, title and interest in and to the Confidential Information are reserved by, and remain the sole property of the Disclosing Party. The Recipient does not acquire any intellectual property rights under this Agreement. Nothing in this Agreement shall be construed as a grant of, or intention or commitment to grant any right, title or interest of any nature whatsoever in or to the Confidential Information.

(g) Recipient agrees that the unauthorized disclosure or use of Confidential Information could cause irreparable harm and significant injury to the Discloser, the amount of which may be difficult to ascertain or quantify, thus, making any remedy at law or in damages inadequate. Therefore, Recipient agrees that Discloser shall have the right to apply to any court of competent jurisdiction for an order restraining any breach or threatened breach of this Section and for any other relief Discloser deems appropriate. This right shall be in addition to any other remedy available to Discloser in law or equity.

(h) This Section 11.1 shall survive any termination of this Agreement for a period of three (3) years.

ARTICLE XII
CONDITIONS

12.1 MH's Conditions Precedent

(1) The obligation of MH to complete the transactions referenced herein shall be subject to and contingent upon the fulfillment of the following conditions precedent ("**MH's Conditions Precedent**") to the satisfaction of MH, as certified or waived in writing by MH, by the dates specified:

(a) MH obtaining the approval of its Board of Directors, within sixty (60) days of the Effective Date, approving MH entering into this Agreement;

(b) MH obtaining an Order in Council of the Lieutenant Governor (Manitoba), within one-hundred and fifty (150) days of the Effective Date, approving MH entering into this Agreement;

(c) MH obtaining the final non-appealable order of the NEB on conditions acceptable to MH, in its sole and absolute discretion, six (6) months before the start of the Contract Term, or by such other date (if any) as the Parties may mutually agree upon, authorizing the export by MH of the Firm Energy to the United States;

(d) the US FCA has been entered into by MISO, MP, and MH and/or an Affiliate of MH, and such other Persons, if any, as MISO may otherwise require enter into the US FCA, on or before June 1, 2016;

(e) the Canadian FCA has been entered into by MH (Power Sales & Operations division) and MH's Transmission Provider on or before June 1, 2016;

(f) the 500 kV US Transmission Interconnection is constructed, commissioned and in-service on or before June 1, 2025;

(g) the 500 kV Canadian Transmission Interconnection is constructed, commissioned and in-service on or before June 1, 2025;

(h) MH receiving from MH's Transmission Provider, on or before June 1, 2025, pursuant to MH's OATT, 133 MW of southbound Firm Transmission Service in respect of the 133 MW Canadian TSR as a result of the Canadian Upgrades being constructed and placed in-service;

(i) MP receiving from MISO, on or before June 1, 2025, pursuant to the TARIFF, 133 MW of southbound Firm Transmission Service in respect of the US Upgrades as a result of the US Upgrades being constructed, and placed in-service; and

(j) the Parties executing on the Effective Date the 2014 Energy Exchange Agreement.

12.2 MP's Conditions Precedent

(1) The obligation of MP to complete the transactions referenced herein shall be subject to and contingent upon the fulfillment of the following conditions precedent ("**MP's Conditions Precedent**") to the satisfaction of MP, as certified or waived in writing by MP, by the dates specified:

(a) the US FCA has been entered into by MISO, MP, and MH and/or an Affiliate of MH, and such other Persons, if any, as MISO may otherwise require enter into the US FCA, on or before June 1, 2016;

(b) the 500 kV US Transmission Interconnection is constructed, commissioned and in-service on or before June 1, 2025;

(c) MP receiving from MISO, on or before June 1, 2025, pursuant to the TARIFF, 133 MW of southbound Firm Transmission Service in respect of the 133 MW US TSR as a result of the US Upgrades being constructed and place in-service;

(d) the final approval of this Agreement by the MPUC on conditions acceptable to MP, within eighteen (18) months of the Effective Date; and

(e) the Parties executing on the Effective Date the 2014 Energy Exchange Agreement.

12.3 Required Approvals

MH shall use Commercially Reasonable Efforts to secure the approvals listed in Sections 12.1(1)(c) and 12.1(1)(h) ("**MH's Required Approval**"). MP shall use Commercially Reasonable Efforts to secure the approvals listed in Sections 12.2(1)(c) ("**MP's Required Approval**"). Each Party agrees to cooperate with and provide reasonable assistance to the other Party, if requested, in order to assist that Party in obtaining the Required Approvals.

12.4 Conditions Precedent Notices

(1) MH shall notify MP as soon as practicable following the satisfaction or waiver or the failure to satisfy or waive any of MH's Conditions Precedent, including the obtaining of or the failure to obtain MH's Required Approval.

(2) MP shall notify MH as soon as practicable following the satisfaction or waiver or the failure to satisfy or waive any of MP's Conditions Precedent including MP's Required Approvals.

12.5 Termination of Agreement

This Agreement shall, subject to the obligation of the Parties in Section 12.3 and Article XI, terminate on the date notice has been received by one Party from the other Party that:

(a) any of MH's Conditions Precedent have not been satisfied and will not be waived; or

(b) any of MP's Conditions Precedent have not been satisfied and will not be waived.

ARTICLE XIII

FORCE MAJEURE

13.1 Force Majeure

(1) Neither Party shall be in breach or liable for any delay or failure in its performance under this Agreement to the extent such performance is prevented or delayed due to a Force Majeure event or circumstance, provided that:

(a) the non-performing Party shall give the other Party notice promptly (and within forty-eight (48) hours if possible) after the non-performing Party's knowledge of the commencement of the Force Majeure, with written confirmation to be supplied within ten (10) calendar days after the commencement of the Force Majeure further describing the particulars of the occurrence of the Force Majeure;

(b) the delay in performance due to the Force Majeure shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure;

(c) the Party whose performance is delayed or prevented: (i) shall proceed with Commercially Reasonable Efforts to overcome the Force Majeure which is preventing or delaying performance; and (ii) shall provide weekly written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure, the schedule for such actions and the expected date by which performance shall no longer be affected by the Force Majeure; and

(d) when the performance of the Party claiming the Force Majeure is no longer being delayed or prevented, that Party shall give the other Party notice to that effect.

(2) For greater certainty, the Parties further acknowledge that the following events or circumstances shall not constitute or form the basis for Force Majeure: (a) the loss of MP's markets; (b) MP's inability to economically use or resell the

Firm Energy, including MP's ability to purchase the Firm Energy, at a price less than the prices provided for in this Agreement; and (c) MH's ability to sell the Firm Energy at a price greater than the prices provided for in this Agreement.

ARTICLE XIV
CREDITWORTHINESS

14.1 Credit Review Procedures

For the purpose of determining whether a Party is able to meet its obligations pursuant to this Agreement, a Party may require commercially reasonable credit review procedures. If requested by a Party, the other Party shall deliver, unless such financial statements are available on "EDGAR" or "SEDAR" or on such other Party's internet website: (a) within 150 calendar days following the end of each fiscal year, a copy of such Party's annual report containing audited consolidated financial statements for such fiscal year; and (b) within 90 calendar days after the end of each of its first three fiscal quarters of each fiscal year, a copy of such Party's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles or such other principles then in effect, provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such Party shall diligently pursue the preparation, certification and delivery of the statements.

14.2 Performance Assurances

(1) Should the creditworthiness, financial strength, or performance viability of a Party (the "**Second Party**") become unsatisfactory to the other Party (the "**Requesting Party**") in such Requesting Party's commercially reasonably exercised discretion with regard to any transaction pursuant to this Agreement, the Requesting Party may require the Second Party to post or provide at the Second Party's option: (a) a Letter of Credit; (b) other collateral or security by the Second Party that is acceptable to the Requesting Party in its commercially

reasonably exercised discretion; (c) a Guarantee Agreement; or (d) some other mutually agreeable method of satisfying the Requesting Party (the items described in (a) through (d) are referred to as "**Performance Assurance**"). The Requesting Party may only request, and the Second Party shall only be required to provide, Performance Assurance in a commercially reasonable amount under the circumstances. The Second Party may request from the Requesting Party that the Performance Assurance be returned or reduced, on the condition that such a request shall only be made once every sixty (60) days during any period when a Performance Assurance has been provided. The Requesting Party shall be required to return or reduce the Performance Assurance, after receipt of the request from the Second Party, if, considering whether the factors that justified the Requesting Party's request for Performance Assurance have been removed or improved, it is commercially reasonable to do so.

(2) Events which may cause the Requesting Party to question the Second Party's financial strength, or performance viability as set out in Section 14.2(1) above, include, but are not limited to, any of the following:

(a) The Requesting Party having knowledge that the Second Party (or its Credit Support Provider, if applicable) is failing to perform or defaulting under terms of other contracts;

(b) The Second Party, or its Credit Support Provider has an Investment Grade Credit Rating (unenhanced by unaffiliated third Party support) and the credit rating falls below an Investment Grade Credit Rating according to at least one of S&P, Moody's or DBRS;

(c) The Second Party, or its Credit Support Provider is rated BBB- by S&P (or the equivalent rating from Moody's or DBRS) and the Second Party or its Credit Support Provider (as applicable) has been either placed on negative credit watch or negative outlook by at least one such rating agency; or

(d) Other material adverse changes in the Second Party's financial condition.

(3) If the Second Party fails to provide Performance Assurance within five (5) Business Days of written demand therefore, such failure will be considered an Event of Default under Article XVII of this Agreement and the Requesting Party shall have the right to exercise any of the remedies provided for under that Article XVII. Nothing contained in this Article XIV shall affect any other credit agreement or arrangement, if any, between the Parties.

(4) If the Second Party provides a Letter of Credit, the Second Party shall: (i) renew the Letter of Credit on a timely basis; and (ii) provide a substitute Letter of Credit at least twenty (20) Business Days prior to the expiration of the outstanding Letter of Credit if the issuer has indicated its intent not to renew such Letter of Credit.

14.3 Grant of Security Interest

(1) To secure its obligations under this Agreement and to the extent either or both Parties (or their Credit Support Provider, if applicable) deliver Performance Assurance hereunder, unless prohibited by applicable law, each Party (a "**Pledgor**") hereby grants to the other Party (the "**Secured Party**") a present and continuing security interest in, and lien on (and right of setoff against), all Performance Assurance delivered by the Pledgor to the Secured Party hereunder and held for the benefit of, such Secured Party, and all proceeds of such Performance Assurance (subject to any secured interest held or maintained by the Pledgor's lender), and Pledgor agrees to take such actions as the Secured Party reasonably requires in order to perfect the Secured Party's security interest in, and lien on (and right of setoff against), such Performance Assurance and any and all proceeds resulting there from or from the liquidation thereof.

(2) Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default, or an uncured event of default under any of the MH/MP Agreements, the Non-defaulting Party may do any one or more of the following: (a) exercise any of the rights and remedies of a Secured Party

with respect to all Performance Assurance delivered by the Defaulting Party, including any such rights and remedies under law then in effect; (b) exercise its rights of setoff against any and all Performance Assurance of the Defaulting Party in the possession of the Non-defaulting Party or its agent up to the amount then owed to it by the Defaulting Party; (c) draw on any outstanding Letter of Credit issued for its benefit up to the amount then owed to it by the Defaulting Party; and (d) liquidate all Performance Assurance then held by or for the benefit of the Secured Party, free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under this Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

(3) In addition to and not in limitation of any other right or remedy (including any right to setoff, counterclaim, or otherwise withhold payment) under applicable law, the Non-defaulting Party may, at its option and in its commercially reasonably exercised discretion and without prior notice to the Defaulting Party, setoff any amounts payable by it to the Defaulting Party under this Agreement (irrespective of currency, place of payment or booking office of obligation) against amounts that the Defaulting Party may owe it under this Agreement and any of the MH/MP Agreements. The obligations of the Parties under this Agreement in respect of such amounts shall be deemed satisfied and discharged to the extent of any such setoff.

(4) The payment by the Defaulting Party of any amounts due under this Agreement and under any of the MH/MP Agreements shall be a condition precedent to the payment of any amounts due by the Non-defaulting Party to the Defaulting Party under any of the MH/MP Agreements.

(5) The Non-defaulting Party shall use Commercially Reasonable Efforts to

provide notice to the Defaulting Party as to the nature and amount of any setoff and recoupment after it is effected, but failure to give notice shall not impair the validity of any setoff.

ARTICLE XV

[TRADE SECRET DATA EXCISED]

15.1 [TRADE SECRET DATA EXCISED]

[**TRADE SECRET DATA EXCISED**]

ARTICLE XVI

DISPUTE RESOLUTION

16.1 Condition Precedent to Arbitration

Prior to initiation of arbitration, any controversy, claim or dispute between the Parties shall be first referred in writing to the Operating Committee for review and attempted resolution. If the controversy, claim or dispute is not resolved within thirty (30) calendar days after referral to the Operating Committee, the matter will be referred to the Executive Officers for review and decision. Any decision by the Executive Officers to resolve a controversy, claim or dispute must be unanimous. If the controversy, claim or dispute is not resolved within thirty (30) calendar days after referral to the Executive Officers, either Party may proceed to arbitration.

16.2 Initiation

Arbitration proceedings must be initiated within one hundred and twenty (120) calendar days of the date the controversy, claim or dispute was first referred to the Executive Officers and shall be initiated by written notice to the other Party setting forth the point or points in dispute. Unless otherwise agreed to in writing by the Parties, failure to initiate arbitration within such one hundred and twenty (120) day period shall be deemed a waiver of the right to arbitrate that controversy, claim or dispute. Provided however, that any such waiver shall not preclude a Party from initiating arbitration proceedings in respect of a similar claim, controversy or dispute based on facts that arise subsequent to the date the controversy, claim or dispute was first submitted to the Executive Officers.

16.3 Arbitration Proceedings

Subject to Section 16.1 above and Section 9.1(3)(g), any and all controversies, claims or disputes between the Parties arising out of or relating to this Agreement or an alleged breach thereof, shall be settled by arbitration. For greater clarity and certainty, arbitration shall not be available to anyone who is not a party to this Agreement, and the aforesaid requirement to arbitrate shall not preclude a Party from seeking contribution, indemnification or damages from another Person in proceedings instituted by third parties in courts of competent jurisdiction. Unless otherwise provided in this Article, the arbitration shall be conducted before three arbitrators and shall be conducted in accordance with the International Commercial Arbitration Act (Ontario), RSO 1990, c.I9 and the UNCITRAL model Law on International Commercial Arbitration as amended and then in effect. Each Party shall select one arbitrator, and the two selected arbitrators shall jointly agree, within 30 days after the last of the two arbitrators have been appointed, on a third arbitrator who shall chair the arbitration. All arbitrators shall be competent by virtue of education and experience in the particular matter subject to arbitration. Before proceeding with the first hearing, each arbitrator shall take an oath of office. The arbitrators shall require witnesses to testify under oath administered by a duly qualified person. The arbitrators shall have jurisdiction and authority only to interpret, apply or determine compliance with the provisions of this Agreement insofar as shall be necessary to determine the particular matter subject to arbitration. The arbitrators shall not have jurisdiction or authority to add to, detract from, or alter the provisions of this Agreement or any applicable law or rule of civil procedure. The arbitrators shall have the power to order specific performance under any and all provisions of this Agreement and no Party can avoid specific performance based on an argument that the other Party has an adequate remedy at law. All arbitrations shall be held in Winnipeg, Manitoba.

16.4 Jurisdiction

The arbitrators may rule on their own jurisdiction, including any objections with respect to the existence or validity of this Agreement. For that purpose, this Article shall be treated as an agreement independent of the terms of the balance of this Agreement. A decision by the arbitrators that this Agreement is null and void shall not entail *ipso jure* the invalidity of this Article. If a Party disputes the authority or jurisdiction of the arbitrators, it shall notify the other Party as soon as the matter alleged to be beyond the authority or jurisdiction of the arbitrators is raised during the arbitration proceedings. The arbitrators may rule on the issue as to whether or not they have the authority or jurisdiction in dispute, either as a preliminary question or in an award on the merits.

16.5 Discovery

Each Party shall have the rights of discovery in accordance with the applicable rules of the Court of Queen's Bench of Manitoba. All issues subject to discovery shall be determined by order of the arbitrators upon motion made to them by any Party. When a Party is asked to reveal material which the Party considers to be proprietary or confidential information or trade secrets, the Party shall bring the matter to the attention of the arbitrators who shall make such protective orders as are reasonable and necessary or as otherwise provided by law.

16.6 Continuation of Performance

Pending the final decision of the arbitrators, the Parties agree, subject to Section 14.2, to diligently proceed with the performance of all obligations, including the payment of all sums required by this Agreement. Payment of any interest shall be as determined by the arbitrator.

16.7 Costs

All fees, costs and expenses of the arbitrators incurred in connection with the arbitration shall be allocated among the Parties by the arbitrators. The nature of the dispute and the outcome of the arbitration shall be factors considered by the arbitrators when allocating such fees, costs, and expenses. Each Party shall be responsible for the fees, costs, and expenses of its own employees, expert consultants and attorneys, and for the costs of exhibits and other incidental costs.

16.8 Enforcement

Any decision (including orders arising out of disputes as to the scope or appropriateness of a request for, or a response to, discovery) of an arbitrator may be enforced in a court of competent jurisdiction with all costs, including court costs and attorney's fees and disbursements, paid by the Party found to be in default or in error. Judgment upon the award rendered by the arbitrators may be entered in any court of competent jurisdiction and may be enforced in accordance with the Convention on the Recognition and Enforcement of Foreign Arbitral Awards.

16.9 Correction and Interpretation of Award

Within thirty (30) calendar days after receipt of an arbitration award, a Party, with notice to the other Party, may request the arbitrators to correct in the award any errors in computation, any clerical or typographical errors or any errors of similar nature, or may request the arbitrators to give an interpretation of a specific point or a part of the award. If the arbitrators consider the request to be justified, they shall make the correction or give the interpretation within thirty (30) calendar days after receipt of the request. The interpretation shall form part of the award. The arbitrators may correct any error as herein-before referred to on their own initiative within thirty (30) calendar days after the date of award. In addition, within thirty (30) calendar days after receipt of an award, a Party with notice to the other Party may request the arbitrators to make an additional award as to claims presented in the arbitration but omitted from the award. If the arbitrators consider the request to be justified, they shall make an additional award within sixty (60) calendar days after receipt of the request. The arbitrators may extend, at their sole discretion if necessary, the period of time within which it shall make a correction, interpretation or an additional award.

ARTICLE XVII
DEFAULT/TERMINATION

17.1 Events of Default

If any of the following events, conditions, or circumstances (each an "**Event of Default**") shall occur and be continuing:

(a) the failure of either Party or any Credit Support Provider of either Party to make any payment to the other Party as required by this Agreement if such amount remains unpaid for a period of five (5) Business Days after the date the Defaulting Party receives written notice from the Non-defaulting Party that the amount is overdue;

(b) the failure by either Party to perform or observe any material obligation to the other Party under this Agreement, that is not excused by an event of Force Majeure, other than obligations for the payment of money, if such failure is not remedied within thirty (30) calendar days after written notice thereof shall have been given by the Non-defaulting Party to the Defaulting Party;

(c) the insolvency or bankruptcy of a Party or its Credit Support Provider or its inability or admission in writing of its inability to pay its debts as they mature, or the making of a general assignment for the benefit of, or entry into any contract or arrangement with, its creditors;

(d) the application for, or consent (by admission of material allegations of a petition or otherwise) to, the appointment of a receiver, trustee or liquidator for a Party or for all or substantially all of its assets, or its authorization of such application or consent, or the commencement of any proceedings seeking such appointment against it without such authorization, consent or application, which proceedings continue undismissed or unstayed for a period of thirty (30) calendar days;

(e) the authorization or filing by a Party or its Credit Support Provider of a voluntary petition in bankruptcy or application for or consent (by admission of material allegations of a petition or otherwise) to the application of any bankruptcy, reorganization, readjustment of debt, insolvency, dissolution, liquidation or other similar law of any jurisdiction or the institution of such proceedings against a Party or its Credit Support Provider without such authorization, application or consent, which proceedings remain undismissed or unstayed for thirty (30) calendar days or which result in adjudication of bankruptcy or insolvency within such time;

(f) in the event that a Party fails to provide Performance Assurance within five (5) Business Days of the date the Performance Assurance was to have been provided in accordance with Section 14.2;

(g) a Party or its Credit Support Provider consolidates or amalgamates with, or merges with or into, or transfers all or substantially all its assets to or reorganizes or reincorporates or reconstitutes into or as another entity and, at the time of such consolidation, amalgamation, merger, transfer, reorganization, reincorporation or reconstitution, the resulting, surviving or transferee entity fails to assume, if applicable, all the obligations of such Party or such Party's Credit Support Provider under this Agreement to which it or its predecessor was a party and, in the case of a Credit Support Provider, such Party has failed to provide a replacement Guarantee Agreement (if a Guarantee Agreement is outstanding) within five (5) Business Days

(h) the occurrence of a Letter of Credit Default that remains uncured for five (5) Business Days;

(i) the occurrence of an uncured Event of Default (as such term is defined in Section 17.1 of the 250 MW System Power Sale Agreement) provided that the Non-defaulting Party shall have the unfettered discretion whether to declare an Event of Default under this Agreement associated with such occurrence;

(j) the occurrence of an uncured Event of Default (as such term is defined in Section 15.1 of the Energy Exchange Agreement) provided that the Non-defaulting Party shall have the unfettered discretion whether to declare an Event of Default under this Agreement associated with such occurrence;

(k) the occurrence of an uncured Event of Default (as such term is defined in Section 15.1 of the 2014 Energy Exchange Agreement) provided that the Non-defaulting Party shall have the unfettered discretion whether to declare an Event of Default under this Agreement associated with such occurrence; or

(l) any material representation or warranty made by the Defaulting Party in this Agreement that is proven to have been false in any material respect when made,

then, and in any such event, the Non-defaulting Party shall have all the rights and remedies available to it at law or in equity, including the right to terminate this Agreement by written notice to the Defaulting Party in accordance with Section 17.3.

17.2 Suspension of Performance

Notwithstanding any other provision of this Agreement, if an Event of Default has occurred and is continuing beyond any applicable cure period, the Non-defaulting Party, upon notice to the Defaulting Party, shall have the right: (a) to suspend performance under this Agreement; provided, however, in no event shall any such suspension continue for longer than (10) Business Days unless an Early Termination Date has been declared and notice thereof given pursuant to Section 17.3; and (b) to the extent an Event of Default has occurred and is continuing beyond any applicable cure period, to exercise any remedies available at law or in equity.

17.3 Right to Terminate Following an Event of Default

(1) If at any time an Event of Default with respect to a Party (the "**Defaulting Party**") has occurred and is then continuing beyond any applicable cure period, the other Party (the "**Non-defaulting Party**") may, by not less than twenty (20) calendar days notice to the Defaulting Party specifying the relevant Event of Default, designate a Business Day not earlier than the day such notice is effective as termination of this Agreement prior to the expiry of the Contract Term (such designated Business Day will constitute an "**Early**

Termination Date”).

(2) In addition to and not in limitation of any other right or remedy (including any right to setoff, counterclaim, or otherwise withhold payment) available to the Non-defaulting Party at law or in equity, the Non-defaulting Party may, at its option and in its commercially reasonably exercised discretion and without prior notice to the Defaulting Party, setoff any amounts payable by it to the Defaulting Party under this Agreement (irrespective of currency, place of payment or booking office of obligation) against amounts that the Defaulting Party may owe it under any of the MH/MP Agreements. The obligations of the Parties under this Agreement in respect of such amounts shall be deemed satisfied and discharged to the extent of any such setoff and recoupment.

(3) The payment by the Defaulting Party of any amounts due under any of the MH/MP Agreements shall be a condition precedent to the payment of any amounts due by the Non-defaulting Party to the Defaulting Party under any of the MH/MP Agreements.

(4) The Non-defaulting Party shall use Commercially Reasonable Efforts to provide notice to the Defaulting Party as to the nature and amount of any setoff and recoupment after it is affected, but failure to give notice shall not impair the validity of any setoff and recoupment.

17.4 MH Termination Events

MH has the right, but not the obligation, to terminate this Agreement (a “**MH Termination Event**”) immediately upon notice to MP upon the termination of any of the MH/MP Agreements prior to the expiry of the term of the applicable agreement, unless the termination occurred due to occurrence of an uncured “Event of Default” (as such term is defined in the applicable agreement) by MH.

17.5 MP Termination Events

MP has the right, but not the obligation, to terminate this Agreement (a “**MP Termination Event**”) immediately upon notice to MH upon the termination of any of the MH/MP Agreements prior to the expiry of the term of the applicable agreement, unless the termination occurred due to occurrence of an uncured "Event of Default" (as such term is defined in the applicable agreement) by MP.

17.6 Payment on Termination

On or as soon as practicable following the effective designation of either an MH Termination Event or an MP Termination Event, MH shall calculate the amounts due and owing by MP to MH, and MP shall calculate the amounts due and owing by MH to MP, as applicable, for the period up to and including the termination date, and each Party shall deliver an invoice to the other Party for the amount due which shall be payable in accordance with Article V.

ARTICLE XVIII
LIMITATION OF LIABILITY

18.1 Limitation of Liability

THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF THE EXPRESS REMEDY OR MEASURE OF DAMAGES PROVIDED IS ALL RIGHTS OR REMEDIES AVAILABLE TO A PARTY AT LAW OR IN EQUITY, SUCH PARTY SHALL BE ENTITLED TO SEEK ALL OR ANY SUCH RIGHTS AND DAMAGES OR REMEDIES. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED IN THIS AGREEMENT, THE OBLIGOR'S LIABILITY

SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE XIX
GENERAL

19.1 Notices

Any notices, demands or requests (other than those operational matters identified by the Operating Committee), required or authorized by this Agreement shall be in writing and may be delivered by hand delivery, mail, electronic mail, confirmed fax, or overnight courier service to:

if to the Manitoba Hydro-Electric Board:

Division Manager

Power Sales & Operations
Manitoba Hydro
360 Portage Avenue
Post Office Box 815
Winnipeg, Manitoba
R3C 2P4
Fax (204) 360-6137

with copies to:

General Counsel
Manitoba Hydro
360 Portage Avenue
Post Office Box 815
Winnipeg, Manitoba
R3C 2P4
Fax (204) 360-6147

if to Minnesota Power:

Vice-President Strategy & Planning
Minnesota Power
30 West Superior St.
Duluth, MN 55802
Fax (218) 723-3915

with copies to:

General Counsel
Minnesota Power
30 West Superior Street
Duluth, MN 55802
Fax (218) 723-3955

Notice by hand delivery shall be effective at the close of business on the day actually received, if received during the recipient's business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight mail, or courier, shall be effective on the next Business Day after it was sent. Notice by electronic mail or confirmed fax shall be effective at the close of business on the day actually received, if received during the recipient's business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. The designation of the persons to be notified or the address of such persons may be changed at any time by similar notice.

19.2 Operational Matters

All issues related to operational matters and notices in respect thereto, as identified by the Operating Committee shall be directed to the appropriate operations personnel at MH and MP. Each Party shall each provide to the other Party a list of contacts for notification on the said operational matters that shall be updated from time to time as required.

19.3 MH's Marketing and Sales Function and MP's Merchant Function

The Parties acknowledge that MH has established an open access transmission tariff and MP is subject to the TARIFF, and MH has adopted, and MP is subject to, the FERC "Standards of Conduct" which require that MH's and MP's respective employees engaged in transmission system operations function independently from MH's and MP's respective marketing and sales employees, and that MH and MP treat all of their respective transmission customers on a non-discriminatory basis. This Agreement is entered into by MH and MP on behalf of their respective marketing and sales functions. Nothing in this Agreement shall obligate either MH's or MP's transmissions function to take or refrain from taking any action.

19.4 Records

Each Party shall keep complete and accurate records and memoranda of its operations hereunder and shall maintain such data as may be necessary to determine with reasonable accuracy any item required hereunder. With respect to invoicing records, each Party shall maintain such records, memoranda and data for the current calendar year plus a minimum of five (5) previous calendar years. Each Party or its respective designee, shall each have the right, at its sole expense, upon reasonable prior notice during the other Party's regular business hours at such Party's primary place of business, to inspect, review and take copies of the other Party's records as far as such records concern monetary matters or other issues under this Agreement and may be reasonably necessary for the purpose of ascertaining the reasonableness and accuracy of any statements of cost, bills or invoices relating to transactions hereunder. Each Party shall treat and shall take reasonable steps to cause its designee to treat such information so inspected, reviewed, or copied as Confidential Information.

19.5 Indemnity

(1) Each Party shall indemnify and save harmless the other Party from and against all claims, actions, suits, proceedings, demands, assessments, judgments, charges, penalties, costs, and expenses which arise or are made or claimed against or suffered or incurred by the other as a result of:

(a) any breach by it of or any inaccuracy of any representation or warranty contained in this Agreement or in any agreement, instrument, certificate or other document delivered pursuant hereto; and

(b) any breach or non-performance by it of any covenant to be performed by it that is contained in this Agreement or in any agreement, certificate or other document delivered pursuant hereto.

(2) The Parties agree:

(a) MH shall be deemed to be in exclusive control of the Firm Energy prior to the delivery by MH and receipt by MP of the Firm Energy at the Delivery Point and MH shall be responsible for, and shall indemnify MP from, any damages or injury MP or any third party may suffer or incur, caused thereby except to the extent such damages or injury were caused by the gross negligence or wilful misconduct of MP; and

(b) MP shall be deemed to be in exclusive control of the Firm Energy from and after delivery by MH and receipt by MP of the Firm Energy at the

Delivery Point and shall be responsible for, and shall indemnify MH from, any damages or injury MH or any third party may suffer or incur, caused thereby except to the extent such damages or injury is caused by the gross negligence or wilful misconduct of MH.

For the purposes of this Section 19.5(2) "gross negligence or wilful misconduct" does not include acts or omissions by a Party that constitute ordinary negligence, and "damages or injury" does not include indirect, incidental, and consequential damages, and without restricting generality of the foregoing, "damages or injury" does not include expenses or liabilities associated with the interruption of power, energy or related services to any third Person.

(3) Each Party shall promptly notify the other Party of claims, demands or actions that may result in a claim for indemnity. Failure to be provided with notice will not relieve a Party from indemnification liability unless, and then only to the extent that, such failure results in the forfeiture by such Party of a substantial right or defense. No settlement of any claim which may result in a claim for indemnity may be made by either Party without the prior consent of the other Party, which consent may not be unreasonably withheld. Neither Party shall be liable under this Agreement in respect of any settlement of a claim unless it has consented in writing to such settlement.

19.6 Governing Law

In respect of matters under this Agreement relating to or arising out of the offering and all other matters in respect of the Firm Energy, the Parties acknowledge that those matters and the applicable provisions of this Agreement concerning same shall be governed and construed in accordance with the laws of the province of Manitoba and Canada. Any disputes arising under this Agreement concerning same that are not resolved by arbitration shall be subject to the exclusive jurisdiction of the courts of the province of Manitoba and the Supreme Court of Canada.

19.7 Waiver of Right to Trial by Jury

Each Party hereby irrevocably waives to the fullest extent permitted by applicable law, any and all rights it may have to trial by jury with respect to any legal proceeding arising out of or relating to this Agreement and any agreement executed or contemplated to be executed in conjunction with this Agreement. This provision is a material inducement to each of the Parties for entering into this Agreement. Each Party hereby waives any right to consolidate any action, proceeding, or counterclaim arising out of or in connection with this Agreement and any other agreement executed or contemplated to be executed in conjunction with this Agreement, or any matter arising hereunder or thereunder in which a jury trial has not or cannot be waived.

19.8 Foreign Sovereign Immunities Act

MH irrevocably agrees to waive the protections of the Foreign Sovereign Immunities Act, 28 U.S.C. §1602, et seq., in connection with this Agreement.

19.9 No Representation or Warranty for Injury

It is acknowledged and agreed that the Firm Energy and related services are inherently dangerous, MH offers no warranty, or representation, express or implied, that the Firms Energy or related services will not cause injury to Person, property or business.

19.10 Surviving Termination

All provisions of this Agreement which by their nature are intended to survive the termination of this Agreement, including, the provisions relating to: (a) the billing by MH to MP of and payment from MP to MH for or related to the Firm Energy; (b) the confidentiality provisions pursuant to Article 11 of this Agreement; and (c) Section 17.6, shall survive the Contract Term or the earlier termination of this Agreement, as the case may be, for a period of three (3) years following the expiration of the Contract Term or the earlier termination of this Agreement.

19.11 Enurement

This Agreement shall be binding upon and its benefits enure to the Parties and their permitted successors and assigns. This Agreement shall not create the relationship between the Parties of a joint venture or a partnership.

19.12 Assignment

Neither this Agreement nor any interest or obligation in or under this Agreement may be assigned (whether by way of security or otherwise) by either Party without the prior written consent of the other Party, except that either Party may, without consent of the other Party, assign this Agreement (in whole and not in part only) to any of their respective Affiliates, including any newly formed Affiliate pursuant to either Party reorganizing its corporate structure, on sixty (60) calendar days advance notice to the other Party provided that:

(a) prior to the effective date of the assignment, Performance Assurance, if required by the non-assigning Party, has been provided to the non-assigning Party in an amount and upon terms satisfactory to the non-assigning Party, in its sole discretion, acting reasonably;

(b) the non-assigning Party shall not be required to pay to the assignee an amount in respect of any Governmental Charges which the non-assigning Party would not have been required to pay to the assigning Party in the absence of such assignment;

(c) the non-assigning Party shall not receive a payment from which an amount has been withheld or deducted, on account of a withholding tax in excess of that which the assigning Party would have been required to so withhold or deduct in the absence of such assignment;

(d) it does not become unlawful for either Party or the assignee to perform any obligation under this Agreement as a result of such assignment; and

(e) no Event of Default or MH Termination Event or MP Termination Event, as applicable, occurs as a result of such assignment.

With respect to the results described in clauses (b) and (c) above, the non-assigning Party will cause the assignee to make, and the assigning Party will make, such reasonable representations as may be mutually agreed upon by the assigning Party, the assignee and the non-assigning Party in order to permit such parties to determine that such results will not occur upon or after the assignment. For greater certainty the assignment in part only of the interest or obligation of MP, to an Affiliate of MP in accordance with and pursuant to the conditions stipulated in this Section 19.12, includes the interest granted pursuant to Article 8 to have the Allocated Environmental Attributes transferred to MP.

19.13 Waiver and Amendment

Unless otherwise specifically provided herein, this Agreement may be altered, modified, varied, or waived, in whole or in part, only by a supplementary written document executed by the Parties.

19.14 Counterparts

This Agreement may be executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

19.15 Recording of Communications

The Parties agree: (a) that each may electronically monitor or record, at any time and from time to time, any and all communications between them; (b) to waive any further notice of such monitoring or recording; (c) to notify and obtain any necessary consents of its officers and employees of such monitoring or recording; (d) that any such monitoring or recording may be offered into evidence in any such suit, trial, hearing, arbitration, or other proceeding; and (e) to furnish appropriately redacted copies of recordings to the other Party within ten (10) Business Days of the other Party's written request.

19.16 Existing Agreements

Each of the Parties are parties to existing agreements with each other and with other third parties. This Agreement shall not affect the obligations and rights of a Party with respect to such existing agreements, except as expressly provided for herein.

19.17 No Other Rights

This Agreement is not intended to and shall not create rights of any character whatsoever in favour of any Person, other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, nor is anything in this

Agreement intended to relieve or discharge the obligation or liability of any third Persons to any Party, nor shall any provision of this Agreement give any third Persons any right of subrogation or action over against any Party.

19.18 Entire Agreement

Subject only to the provisions of the Non-Disclosure Agreement, this Agreement represents the entire agreement between the Parties with respect to the subject matter hereof and supersedes all prior oral and written proposals and communications pertaining hereto, including the Term Sheet. There are no representations, conditions, warranties or agreements, express or implied, statutory or otherwise, with respect to or collateral to this Agreement other than contained herein or expressly incorporated herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed on the date first above written.

THE MANITOBA HYDRO-ELECTRIC BOARD

____

By: A.D. Cormie, Division Manager Power Sales & Operations

I HAVE AUTHORITY TO BIND THE MANITOBA HYDRO-ELECTRIC BOARD

MINNESOTA POWER, an operating division of ALLETE, Inc.

____

By: Alan R. Hodnik, Chairman, President and Chief Executive Officer

I HAVE AUTHORITY TO BIND ALLETE, INC.

Appendix A
[Trade Secret Data Excised]

Appendix B
MH's Energy Resources

[TRADE SECRET DATA EXCISED]

APPENDIX C

INTERBANK TRANSFER OF FUNDS ACCOUNT DESIGNATIONS

For THE MANITOBA HYDRO-ELECTRIC BOARD:

US Dollar Wire Payments

[TRADE SECRET DATA EXCISED]

For MINNESOTA POWER

US Dollar Payments

[TRADE SECRET DATA EXCISED]

Appendix D
[TRADE SECRET DATA EXCISED]

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

APPENDIX E

[TRADE SECRET DATA EXCISED]

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

APPENDIX F
[TRADE SECRET DATA EXCISED]

APPENDIX G
[TRADE SECRET DATA EXCISED]

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

APPENDIX H
[TRADE SECRET DATA EXCISED]

APPENDIX I

[TRADE SECRET DATA EXCISED]

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

APPENDIX I

[TRADE SECRET DATA EXCISED]

APPENDIX J
[TRADE SECRET DATA EXCISED]

APPENDIX K
[TRADE SECRET DATA EXCISED]

APPENDIX L
[TRADE SECRET DATA EXCISED]

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

APPENDIX M
[TRADE SECRET DATA EXCISED]

APPENDIX N
[TRADE SECRET DATA EXCISED]

2014 ENERGY EXCHANGE AGREEMENT

between

THE MANITOBA HYDRO-ELECTRIC BOARD

- and –

MINNESOTA POWER, an operating division of ALLETE, Inc.

DATED July 30, 2014

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SCHEUDULE B- [TRADE SECRET DATA EXCISED]

TRADE SECRET DATA EXCISED

2014 ENERGY EXCHANGE AGREEMENT

DATED July 30, 2014

BETWEEN:

THE MANITOBA HYDRO-ELECTRIC BOARD,
(hereinafter referred to as "MH"),

- and –

MINNESOTA POWER, an operating division of ALLETE, Inc.,
(hereinafter referred to as "MP").

WHEREAS, MP, and MH are the owners and operators of electric generation and transmission facilities in the United States of America and in Canada, respectively, and are engaged in the generation, transmission, distribution and sale of electric energy;

AND WHEREAS, MP, MH and 6690271 Manitoba Ltd. entered into a term sheet dated September 27, 2013, (the "**Term Sheet**") for a number of proposed transactions;

AND WHEREAS, each of the aforesaid proposed transactions contemplated by the Term Sheet was subject to a number of conditions including the execution and delivery of definitive written agreements;

AND WHEREAS, this Agreement is the definitive agreement for one of the proposed transactions being: (i) the sale by MP and the purchase by MH of MP's Energy; (ii) MH agreeing to pay for MP's Pumped Energy; and (iii) MP agreeing to pay for MH's Stored Energy;

AND WHEREAS, MH agrees to purchase and MP agrees to sell MP's Energy pursuant to the terms and conditions set forth in this Agreement;

AND WHEREAS, MH agrees to pay MP for MP's Pumped Energy pursuant to the terms and conditions set forth in this Agreement;

AND WHEREAS, MP agrees to pay MH for MH's Stored Energy pursuant to the terms and conditions set forth in this Agreement;

AND WHEREAS, the Parties require governmental permits and approvals for the import and export of electric energy;

AND WHEREAS, MP is a member of MISO and subject to applicable MISO tariffs, and MH is a coordinating member of MISO.

NOW, THEREFORE, in consideration of the mutual promises and covenants of each Party to the other contained in this Agreement and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties covenant and agree as follows:

ARTICLE I
INTERPRETATION

1.1 Defined Terms

Unless otherwise specified in this Agreement, the following terms shall, for the purposes of this Agreement, have the following meanings:

"**133 MW Energy Sale Agreement**" shall mean the 133 MW Energy Sale Agreement entered into between MP and MH concurrently with this Agreement.

"**250 MW System Power Sale Agreement**" shall mean the 250 MW System Power

Sale Agreement entered into between MP and MH on May 19, 2011.

"500 kV Canadian Transmission Interconnection" shall have the meaning set forth in Section 3.1(1)(g).

"500 kV Transmission Interconnection" shall have the meaning set forth in Section 3.1(1)(g).

"**500 kV Transmission Interconnection In-service Date**" shall mean when the 500 kV Transmission Interconnection is commissioned and comes into service.

"500 kV US Transmission Interconnection" shall have the meaning set forth in Section 3.1(1)(g).

"Affiliate" shall mean any Person that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with MP or MH and shall include a wholly owned subsidiary of MP or MH.

"**Agreement**" means this 2014 Energy Exchange Agreement and all amendments thereto.

"Ancillary Services" shall have the meaning set forth in the TARIFF.

"**Balancing Authority**" shall have the meaning set forth in the TARIFF.

"**Bankruptcy Code**" shall have the meaning set forth in Section 9.1(1)(k).

"Business Day" shall mean Monday through Friday, excluding Canadian banking holidays (such banking holidays shall be as recognized by the Canadian Payments Association or any successor agency) and United States banking holidays (such banking holidays shall be as recognized by the Federal Reserve Board or any successor agency).

"**Canadian FCA**" shall have the meaning set forth in Section 3.1(1)(f).

"**Canadian TSRs**" shall have the meaning set forth in Section 3.1(1)(d).

"**Canadian Upgrades**" shall have the meaning set forth in Section 3.1(1)(e).

"**Centrally Operated Market**" shall mean a centrally operated structure or structures bringing together buyers and sellers to facilitate the exchange of wholesale electricity products and/or related services.

"**Commercially Reasonable Efforts**" shall mean those efforts expended by a Party, acting reasonably, under normal commercial conditions to identify, develop, and implement a solution to an issue or problem that is cost effective (taking into account the complexity and importance of the issue or problem being addressed) and is also consistent with applicable legal requirements, rules governing any applicable Market and Good Utility Practice if the Party is MP and Good Utility Hydro Practice if the Party is MH.

"**Confidential Information**" shall have the meaning set forth in Section 10.1(a).

"**Contract Term**" shall mean, the twenty (20) year period from the 500 kV Transmission Interconnection In-service Date**.**

"**Contract Year**" shall mean a twelve-month period, June 1 through May 31 of the following calendar year, whether or not within the Contract Term.

"**Credit Support Provider**" shall mean a Person approved by the Requesting Party who provides Performance Assurance on behalf of the Second Party.

"Day-Ahead Basis" shall mean in advance, not later than 11 a.m. (EST) of the Business Day prior to any day that MP is to make available MP's Energy to MH.

"**Day-Ahead Energy and Operating Reserve Market**" shall mean the day-ahead market established pursuant to and defined by the TARIFF.

"**Day-Ahead Energy Price**" shall have the meaning set forth in the TARIFF.

“Day-Ahead Offer Basis” shall mean in advance, not later than 11 a.m. (EST) of the Business Day prior to any day that MP offers MP’s Pumped Energy to MH or MH offers MH’s Stored Energy to MP, as applicable.

“**DBRS**” shall mean DBRS Limited or its successor.

“**Defaulting Party**” shall have the meaning set forth in Section 15.3(1).

“**Delivery Point**” shall have the meaning set forth in Section 2.2(1).

“**Discloser**” shall have the meaning set forth in Section 10.1.

“**Early Termination Date**” shall have the meaning set forth in Section 15.3(1).

“**Effective Date**” shall mean the date this Agreement is executed by the Parties.

“**Energy Exchange Agreement**” shall mean the Energy Exchange Agreement entered into between MP and MH on May 19, 2011.

“**Environmental Attributes**” shall mean the rights to any existing or future environmental benefits or attributes, credits, renewable characteristics, avoided emissions, avoided greenhouse gas emissions, emission reductions, emissions or greenhouse gas emissions associated with, related to or derived or resulting from the generation of electricity.

“**Event of Default**” shall have the meaning set forth in Section 15.1.

“**Executive Officers**” shall be, in the case of MH the Vice-President Generation Operations, and in the case of MP the Vice-President Strategy and Planning, or its successor or such other officer designated by each Party from time to time.

“**FERC**” shall mean the Federal Energy Regulatory Commission or its successor.

“**Financial Schedule**” shall have the meaning set forth in the TARIFF.

"**Firm Point-to-Point Transmission Service**" shall have the meaning set forth in the applicable OATT.

"**Firm Transmission Service**" shall mean transmission service provided pursuant to the OATT of either Party's Transmission Provider, being either Firm Point-to-Point Transmission Service or Network Integration Transmission Service, or the highest priority transmission service available pursuant to either Party's OATT, or in the event that either Party does not have an OATT, the highest priority transmission service available to that Party for the delivery of energy and the supply of capacity.

"**Force Majeure**" shall mean an event or circumstances that prevents or delays one Party (the "**Claiming Party**") from performing its obligations under this Agreement and that is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and that, by the exercise of Good Utility Practice, if the Claiming Party is MP and that, by the exercise of Good Hydro Utility Practice, if the Claiming Party is MH is unable to overcome or avoid or cause to be avoided, including but not restricted to, acts of God, [**TRADE SECRET DATA EXCISED**] strikes, lockouts and other labour disturbances, epidemics, pandemic, war (whether or not declared), blockades, acts of public enemies, acts of sabotage or terrorism, civil insurrection, riots or civil disobedience, any situation where delivery or acceptance will endanger the Claiming Party's facilities or endanger that Party's system operations, explosions, acts or omissions of any Governmental Authority taken on or after the Effective Date, (including the adoption or change in any law or regulation or environmental constraints lawfully imposed by such Governmental Authority) but only if, and to the extent that, such action or inaction by such Governmental Authority prevents or delays performance and/or renders the Claiming Party unable, despite due diligence, to obtain any licenses, permits, or approval required by any Governmental Authority, and the issuance of any order, injunction, or other legal or equitable decree to the extent that any of the foregoing prevents or delays the performance of a Claiming Party's obligations hereunder.

"**Good Hydro Utility Practice**" shall mean, at any particular time, any of the practices, methods, and acts engaged in or approved by a significant portion of the hydro-electric utilities located in North America during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could be expected to produce the desired result at a reasonable cost consistent with reliability, safety, and expedition. Good Hydro Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but includes a range of acceptable practices, methods, or acts.

"**Good Utility Practice**" shall mean, at any particular time, any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utilities located in North America during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could be expected to produce the desired result at a reasonable cost consistent with reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but includes a range of acceptable practices, methods, or acts.

"**Governmental Authority**" shall mean any federal, state, or provincial government, parliament, legislature, or any regulatory authority, agency, commission or board of any of the foregoing, or any political subdivision thereof, or any court, or, without limitation, any other laws, regulation or rule-making entity, having jurisdiction in the relevant circumstances, or any Person acting under the authority of any of the foregoing, or any other authority charged with the administration or enforcement of applicable laws.

"**Governmental Charges**" shall mean all applicable federal, state, provincial and local ad valorem, property, occupation, severance, generation, first use, conservation, or energy, transmission, utility, gross receipts, privilege, sales, use, consumption, excise and other taxes (other than taxes based on income or net worth), charges, emission allowance costs, duties, tariffs, levies, licenses, fees, permits, assessments, adders or surcharges (including public purposes charges and low income bill payment assistance charges), imposed or authorized by a Governmental Authority, independent system operator, utility, transmission and distribution provider or similar Person, however styled or payable.

[**TRADE SECRET DATA EXCISED**]

"**Guarantee Agreement**" shall mean a guarantee provided to the Requesting Party by a Credit Support Provider with an Investment Grade Credit Rating as Performance Assurance pursuant to Section 13.2 in a form acceptable to the Requesting Party acting with commercially reasonable discretion.

"**Interest Rate**" shall mean, for any date, the lesser of: (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in The Wall Street Journal under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%); or (b) the maximum rate permitted by applicable law.

"**Investment Grade Credit Rating**" shall mean with respect to any Person, a rating (unenhanced by unaffiliated third party support) of not less than: (a) BBB- from S&P; or (b) Baa3 from Moody's; or (c) BBB(low) from DBRS, then assigned to the lower of: (i) its unsecured, senior long-term debt obligations; or (ii) if applicable, its issuer rating and, in each instance, unenhanced by unaffiliated third party support and not on "credit watch" or "negative outlook", provided, however, that in the event that such Person has a rating from one of the aforesaid rating agencies below the required level, the lowest such rating shall apply for the purposes of this definition.

"**Letter(s) of Credit**" shall mean one or more irrevocable, transferable, standby letters of credit, issued by a commercial bank, as defined in either the Federal Deposit Insurance Act (United States) or the Bank Act (Canada), or successor legislation, operating from an office in either the United States or Canada whose credit rating is, at such time of issuance, at least "A-'' by S&P or "A3" by Moody's or A(low) by DBRS, or an equivalent rating by any successor rating agency thereof (if any) in a form as the issuing bank may request and as may be acceptable in a commercially reasonable manner to the Party in whose favor the Letter of Credit is issued.

"Letter of Credit Default" shall mean with respect to an outstanding Letter of Credit, the occurrence of any of the following events: (a) the issuer of the Letter of Credit shall fail to maintain a credit rating of at least "A-" by S&P or "A3" by Moody's or A(low) by DBRS; (b) the issuer of such Letter of Credit shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of, such Letter of Credit; (c) such Letter of Credit shall expire or terminate, or shall fail to or cease to be in full force and effect at any time during the Contract Term; (d) any event analogous to an event specified in Section 15.1(c), (d),(e) or (g) of this Agreement shall occur with respect to the issuer of such Letter of Credit; or (e) twenty (20) Business Days prior to the expiration or termination date of a Letter of Credit, such Letter of Credit is not extended or replaced with a Letter of Credit for an amount at least equal to that of the Letter of Credit being replaced.

"**Local Balancing Authority**" shall have the meaning set forth in the TARIFF.

"**Market**" or "**Markets**" shall mean:

(a) a Centrally Operated Market; and/or

(b) the wholesale purchase and sale of electricity products and/or related services on a bilateral basis.

"**Market Participant**" shall have the meaning set forth in the TARIFF.

"**Market Settlement Amounts**" shall mean any and all charges attributable to either Party arising out of a process of determining charges established and maintained at any time and from time to time by a Market (or a Transmission Provider).

"**MH Termination Event**" shall have the meaning set forth in Section 15.4.

"**MH/MP Agreements**" shall mean this Agreement, the 250 MW System Power Sale Agreement, the Energy Exchange Agreement and the 133 MW Energy Sale Agreement.

"**MH's Ancillary Services**" shall mean those Ancillary Services and other reasonably similar services and products, associated, directly or indirectly, with the transmission of MP's Energy.

"**MH's Conditions Precedent**" shall have the meaning set forth in Section 11.1.

"**MH's Stored Energy**" shall have the meaning set forth in Section 2.5(2).

"**MH's Stored Energy Price**" shall have the meaning set forth in Section 4.1(3).

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"**Minimum MP's Energy Requested Amount**" shall have the meaning set forth in Section 2.1(2).

"**MISO**" shall mean the Midcontinent Independent System Operator, Inc.

"**Moody's**" shall mean Moody's Investors Service Inc. or its successor.

"**MP Charges**" shall have the meaning set forth in Section 3.1(5)(b).

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"**MP Termination Event**" shall have the meaning set forth in Section 15.5.

"**MP's Ancillary Services**" shall mean those Ancillary Services and other reasonably similar services and products, associated, directly or indirectly, with the generation of MP's Energy.

"**MP's Condition Precedent**" shall have the meaning set forth in Section 11.2.

"**MP's Designated Peak Hours**" shall mean any four (4) hours in any day during the Contract Term, of which MP has provided advance notice to MH, not later than 8 a.m. (EST) of the Business Day occurring immediately prior to the day that MP's Energy is to be made available by MP to MH.

"**MP's Energy**" shall have the meaning set forth in Section 2.1(1).

"**MP's Energy Price**" shall have the meaning set forth in Section 4.1(1).

"**MP's Load Zone**" shall mean the geographic area that encompasses the major portion of MP's electric load in the States of Minnesota and Wisconsin.

"**MP's Pumped Energy**" shall have the meaning set forth in Section 2.5(1).

"**MP's Pumped Energy Price**" shall have the meaning set forth in Section 4.1(2).

"**NERC**" shall mean the North American Electric Reliability Corporation or its successor.

"**Network Integration Transmission Service**" shall have the meaning set forth in the applicable OATT.

"**Non-defaulting Party**" shall have the meaning set forth in Section 15.3(1).

"**Non-Disclosure Agreement**" shall mean that certain non-disclosure agreement between the Parties, effective November 10, 2006, as amended.

"**Northbound 133 MW Canadian TSR**" shall have the meaning set forth in Section 3.1(1)(d)(i)(A).

"**Northbound 133 MW US TSR**" shall have the meaning set forth in Section 3.1(1)(a)(i)(A).

"**On-Peak Hours**" shall mean HE 7:00 CPT to HE 22:00 CPT Monday to Friday.

"**Open Access Transmission, Energy and Operating Reserve Markets Tariff**" or "**TARIFF**" shall mean the Open Access Transmission, Energy and Operating Reserve Markets FERC Electric Tariff, including all schedules and attachments thereto, of the Midcontinent Independent System Operator, Inc. issued on May 1, 2013, as amended, supplemented, or replaced from time to time.

"**Open Access Transmission Tariff**" or "**OATT**" shall mean a transmission tariff as it may be in effect from time to time that: (a) in the case of MP's Transmission Provider, has been filed with and accepted by FERC as complying with FERC's then current open access transmission, comparability, and nondiscrimination requirements; and (b) in the case of MH, provides reciprocal open access transmission service on sufficiently comparable and nondiscriminatory terms so as to entitle MH to use the transmission tariff of Transmission Providers in the United States; and (c) in the case of a third party, has been filed with and accepted by FERC as complying with FERC's then current open access transmission, comparability, and nondiscrimination requirements, or provides reciprocal open access transmission service so as to entitle such entity to transmit electricity with entities whose transmission tariffs have been filed with and accepted by FERC as a transmission tariff.

"**Operating Committee**" shall have the meaning set forth in Section 8.1(1).

"Party" shall mean either MH or MP and "**Parties**" means both MH and MP.

"**Performance Assurance**" shall have the meaning set forth in Section 13.2(1).

"**Person**" shall mean an individual, partnership, corporation, trust, unincorporated association, syndicate, joint venture, or other entity or Governmental Authority.

"**Pledgor**" shall have the meaning set forth in Section 13.3(1).

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"**Recipient**" shall have the meaning set forth in Section 10.1.

"**Representative**" shall have the meaning set forth in Section 10.1(b)(i).

"**Requesting Party**" shall have the meaning set forth in Section 13.2(1).

"**S&P**" shall mean Standard & Poor's Rating Services (a division of McGraw-Hill Inc.) or its successor.

"**Schedule**" or "**Scheduling**" shall mean the actions of seller, buyer, and their designated representatives, of notifying, requesting, and confirming to each other the quantity of MP's Energy to be delivered on any given day or days during the Contract Term.

"**Scheduled**" shall mean the result of Scheduling.

"**Seams Costs**" shall mean any and all transmission and transmission service and related costs applied by one Market for the transmission of energy and related products from that Market or to that Market at the boundary of that Market.

"SEP Contract Year" shall have the meaning set forth in Section 4.1(3).

"**Second Party**" shall have the meaning set forth in Section 13.2(1).

"**Secured Party**" shall have the meaning set forth in Section 13.3(1).

"**Transmission Provider(s)**" shall mean, collectively, the Person or Persons as applicable who direct the operation of the Transmission Provider(s) System.

"**Transmission Provider(s) System**" shall mean the contiguously interconnected electric transmission and sub-transmission facilities, including land rights, material, equipment and facilities owned, controlled, directed, and or operated by the

Transmission Provider(s) that transmits and distributes electrical energy.

"**Transmission Service**" shall have the meaning set forth in Sections 3.1(2)(a), 3.1(3), 3.1(4)(a), and 3.1(5).

"**U.S. Dollars or US $**" shall mean lawful money of the United States of America.

"**US FCA**" shall have the meaning set forth in Section 3.1(1)(c).

"**US TSRs**" shall have the meaning set forth in Section 3.1(1)(a)(ii)(B).

"**US Upgrades**" shall have the meaning set forth in Section 3.1(b).

"**WPS**" shall have the meaning set forth in 3.1(1)(a)(ii).

1.2 <u>Interpretation</u>

Unless the context otherwise requires, this Agreement shall be interpreted in accordance with the following:

(a) words singular and plural in number shall be deemed to include the other and pronouns having masculine or feminine gender shall be deemed to include the other;

(b) any reference in this Agreement to any Person includes its successors and permitted assigns, and, in the case of any Governmental Authority, any Person succeeding to its functions and capacities; any reference in this Agreement to any section or Appendix means and refers to the section contained in, or Appendix attached to, this Agreement;

(c) other grammatical forms of defined words or phrases have corresponding meanings to the defined words or phrases;

(d) a reference to writing includes typewriting, printing, lithography, photography, and any other mode of representing or reproducing words, figures or symbols in a lasting and visible form, including electronic mail;

(e) a reference to a Party to this Agreement includes that Party's successors and permitted assigns;

(f) a reference to a document or agreement, including this Agreement, includes a reference to that document or agreement as amended from time to time and includes any exhibits or attachments thereto;

(g) headings are inserted for convenience only and shall not affect the interpretation of this Agreement or any section thereto;

(h) the word "including" means "including without limitation"; and

(i) the preamble hereto shall not form part of this Agreement.

1.3 No Presumption

The Parties are both represented by counsel, have both participated in the negotiation and drafting of this Agreement, and have endeavoured to ensure that the terms of this Agreement are as clear as possible. Accordingly, in interpreting this Agreement there shall be no presumption in favour of or against any Party on the basis that it was or was not the drafter of this Agreement or any individual provision thereof.

ARTICLE II

ENERGY TRANSACTIONS

2.1 MP's Energy

(1) Subject to the provisions of this Agreement, during the Contract Term MP shall sell to MH and MH shall purchase from MP that quantity of energy that MH, subject to Section 2.1(2), in its sole discretion requests on a Day-Ahead Basis ("**MP's Energy**"), provided that the energy quantity requested in any hour shall not exceed 133 MWh per hour. MP shall offer and make available MP's Energy to the Delivery Point and MH shall accept delivery at the Delivery Point and pay for MP's Energy.

(2) MH agrees to request from MP pursuant to Section 2.1(1) the energy quantity amount (expressed in MWh) determined as follows:

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over the Contract Term (the "**Minimum MP's Energy Requested Amount**").

(3) The Parties acknowledge that in accordance with Section 3.1 the Transmission Service shall be utilized for the delivery and receipt of MP's Energy. The Parties may by mutual agreement also request additional Firm Transmission Service or additional transmission service that is not Firm Transmission Service on a daily and/or monthly basis for the delivery and receipt of MP's Energy.

(4) The Parties acknowledge that MP has in its sole discretion the right, but not the obligation, to source and/or supply and/or sell MP's Energy from third party purchases and/or Markets available to MP. Without limiting the generality of the foregoing, the Parties acknowledge that MP has the right but not the obligation to utilize any Market mechanisms that are available to MP throughout the Contract Term.

(5) The Parties acknowledge and agree that: (a) MP has retained all Environmental Attributes for MP's Energy; and (b) for environmental reporting purposes, the Environmental Attributes of MP's Energy, is electrical energy that is not sourced from any specific generation type or resource and has Environmental Attributes equivalent to energy that is associated with the applicable market in which the majority of MP's Load Zone is physically situated and shall be reported by each of the Parties in that manner, in any reports that are filed by each of the Parties in respect of the purchase and sale of MP's Energy pursuant to this Agreement.

2.2 MP's Energy Delivery Point

(1) The Parties agree that the delivery point for MP's Energy that is sold by MP and purchased by MH under this Agreement shall be at the point or points where MH's major transmission facilities cross the international boundary between the province of Manitoba and the United States of America (the "**Delivery Point**").

(2) The Delivery Point for any portion of MP's Energy to be sold and purchased herein may only be changed with the consent of the Parties provided that the Party receiving a request from the other Party to change the Delivery Point must use Commercially Reasonable Efforts in responding to such request.

2.3 MP's Energy Title and Risk of Loss

Title to and risk of loss of MP's Energy sold and purchased under this Agreement shall pass from MP to MH at the Delivery Point.

2.4 MP's Energy Ancillary Services

(1) The Parties acknowledge and agree that: (a) MP shall be entitled to retain all of MP's Ancillary Services; (b) the price for MP's Energy does not include any value in respect of or related to MP's Ancillary Services; (c) MH shall use Commercially Reasonable Efforts to comply with all reasonable requests by MP to participate in the Market in respect of or related to MP's Ancillary Services; (d) MH shall be entitled to retain all of MH's Ancillary Services; (e) the price for MP's Energy is inclusive of the value in respect of or related to MH's Ancillary Services; and (f) MP shall use Commercially Reasonable Efforts to comply with all reasonable requests by MH to participate in the Market in respect of or related to MH's Ancillary Services.

(2) In the event that MH receives any compensation or payment from the MISO or otherwise for MP's Ancillary Services that were offered or scheduled by MP, MH shall remit such compensation or payment to MP. In the event that MP receives any compensation or payment from MISO or otherwise for MH's Ancillary Services that were offered or scheduled by MH, MP shall remit such compensation or payment to MH.

2.5 MP's Pumped Energy and MH's Stored Energy

MP's Pumped Energy

(1) Subject to the provisions of this Agreement, during the Contract Term MP shall be entitled to offer to MH on a Day-Ahead Offer Basis when MP, in its sole discretion, determines excess renewable energy is available: (a) during the twelve (12) month period of each calendar year that is entirely within the

Contract Term, up to a total of 750,000 MWh of energy; and (b) during such period of time within a portion of a calendar year that is within the Contract Term (and that calendar year is not entirely within the Contract Term), up to a total amount determined using a pro-rated portion of 750,000 MWh of energy for an entire calendar year, calculated by multiplying 750,000 by the total number of days in that calendar year that were within the Contract Term and dividing the result by the number of days in such calendar year (all energy offered by MP pursuant to this Section 2.5(1)(a) and (b) shall collectively be referred to as "**MP's Pumped Energy**"). MP's Pumped Energy shall not exceed in any hour 383 MWh under the Energy Exchange Agreement and this Agreement, subject to further agreement by MP and MH. The Parties acknowledge and agree that MP shall have no obligation to sell and deliver any quantity of MP's Pumped Energy and MH shall have no obligation to purchase and receive any quantity of MP's Pumped Energy. MH agrees to pay MP for the applicable quantity of MP's Pumped Energy at MP's Pumped Energy Price and the provisions of Section 3.2(9) shall apply to the Parties in respect of MP's Pumped Energy.

(2) MH's Stored Energy

Subject to the provisions of this Agreement, during the Contract Term MP shall be entitled to require MH to offer to MP the amount of energy that MP has requested on a Day-Ahead Offer Basis that MH offer to MP during the Contract Term, provided that: (a) the total amount of energy offered by MH shall not exceed for the corresponding time period referred to in Section 2.5(1)(a) or (b) above, the total amount of MP's Pumped Energy that was offered by MP during that same time period; and (b) the energy offered by MH shall not exceed in any hour 383 MWh under the Energy Exchange Agreement and this Agreement subject to further agreement by MP and MH (all energy offered by MH pursuant to the request of MP pursuant to this Section 2.5(2)(a) and (b) shall collectively be referred to as "**MH's Stored Energy**"). The Parties acknowledge and agree that MH shall have no obligation to sell and deliver any of MH's Stored Energy and MP shall have no obligation to purchase and receive any quantity of MH's Stored Energy. MP agrees to pay MH for the applicable quantity of MH's Stored Energy at MH's Stored Energy Price and the provisions of Section 3.2(9) shall apply to the Parties in respect of MH's Stored Energy.

ARTICLE III
SCHEDULING AND DELIVERY

3.1 Transmission

(1) The Parties acknowledge and agree:

(a) Transmission service requests have been filed on the MISO OASIS:

(i) by MH for 883 MW of northbound transfer capability which includes:

(A) MH pursuant to transmission service request number 79258492 for 133 MW of northbound transfer capability (the "**Northbound 133 MW US TSR**); and

(ii) by MP, MH and Wisconsin Public Service Corporation ("**WPS**") for 883 MW of southbound transfer capability which includes:

(A) MP pursuant to transmission service request 76703672 for 250 MW of southbound transfer capability; and

(B) MP pursuant to transmission service request number 79258361 for 133 MW of southbound transfer capability (such filed MP transmission service requests collectively the "**US TSRs**"),

and for recognition of such transfer capability as Firm Transmission Service under the TARIFF;

(b) to accommodate the US TSRs, additions, alterations, and improvements will be required to MP's transmission system (the "**US Upgrades**" which includes without limitation, the 500 kV US Transmission Interconnection);

(c) a facilities construction agreement would be required to be entered into in accordance with the requirements of MISO for the construction and maintenance of the US Upgrades (the "**US FCA**");

(d) MH has filed individual transmission service requests on the MH OASIS (such filed transmission service requests collectively the "**Canadian TSRs**") for:

(i) a total 883 MW of northbound transfer capability which includes:

(A) MH's transmission service request number 76703155 (as of the Effective Date) for 500 MW of northbound transfer capability pursuant or any successor transmission service request for a minimum of 200 MW of northbound transfer capability (the "**Northbound 500 MW Canadian TSR**"); and

(ii) a total 883 MW of southbound transfer capability;

and for recognition of such transfer capability as Firm Transmission Service under MH's OATT;

(e) to accommodate the Canadian TSRs, additions, alterations, and improvements will be required to MH's Transmission Providers transmission system (the "**Canadian Upgrades"** which includes without limitation, the 500 kV Canadian Transmission Interconnection");

(f) a facilities construction agreement would be required to be entered into in accordance with the requirements of MH's Transmission Provider for the construction and maintenance of the Canadian Upgrades (the "**Canadian FCA**");

(g) the US Upgrades and the Canadian Upgrades are expected to consist of the United States portion and the Canadian portion, respectively, of a new 500 kilovolt international transmission interconnection utilizing a route between the Dorsey sub-station in Manitoba and the Blackberry sub-station near Grand Rapids, Minnesota (the Canadian and United States components of the said transmission interconnection collectively referred to the "**500 kV Transmission Interconnection**")(the United States component of the 500 kV Transmission Interconnection referred to as the "**500 kV US Transmission Interconnection**") (the Canadian component of the 500 kV Transmission Interconnection referred to as the "**500 kV Canadian Transmission Interconnection**");

(h) if a Canadian FCA is entered into, MH agrees it will fund all of the costs for constructing the Canadian Upgrades on the conditions and terms set out in the Canadian FCA and will comply with the provisions of such agreement;

(i) if a US FCA is entered into, MH agrees it will contribute or cause an Affiliate of MH to contribute to the costs for constructing and maintaining the US Upgrades on the conditions and terms set out in the US FCA or otherwise by separate agreement with MH and/or its Affiliate and MP, and MH and/or its Affiliate, as applicable, agree to comply with the provisions of such agreement(s); and

(j) if a US FCA is entered into, MP agrees it will contribute to the costs for constructing and maintaining the US Upgrades on the conditions and terms set out in the US FCA or otherwise by separate agreement with MH and/or its Affiliate, as applicable, and MP agrees it will comply with the provisions of such agreement(s).

(2) MH acknowledges and agrees that the Canadian Upgrades, if built and completed, shall enable the provision of Firm Transmission Service in respect of the purchase of MP's Energy that is sold by MP and purchased by MH pursuant to this Agreement from the Delivery Point, subject to:

(a) MH receiving from MH's Transmission Provider pursuant to MH's OATT, 133 MW of northbound Firm Transmission Service in respect of the Northbound 133 MW Canadian TSR as a result of the Canadian Upgrades being constructed and placed in-service.

(3) MH agrees:

(a) to use Commercially Reasonable Efforts to obtain the Firm Transmission Service referred to in Section 3.1(2)(a) above; and

(b) subject to Sections 3.1(1) and 3.1(2)(a) to arrange and pay for Firm Transmission Service for the delivery of the MP's Energy to be received and purchased by MH pursuant to this Agreement from the Delivery Point. Without limiting the generality of the foregoing, MH shall be responsible for the payment of any and all Market Settlement Amounts, transmission charges and associated charges, congestion charges, transmission loss charges and/or transmission energy losses, and all other charges assessed by MH's Transmission Provider for the delivery of MP's Energy made available and sold by MP pursuant to this Agreement from the Delivery Point. For greater certainty, no provision of this Agreement shall obligate MH and/or any Affiliate of MH to pay for any of the costs of constructing, operating or maintaining the Canadian Upgrades, or any of the costs of constructing, operating and maintaining the US Upgrades and such obligations, will be as set out in the Canadian FCA and the US FCA, as applicable.

(4) MH acknowledges and agrees that the US Upgrades, if built and completed, shall enable the provision of Firm Transmission Service, in respect of the purchase of the Firm Energy that is made available and sold by MP and purchased by MH pursuant to this Agreement to the Delivery Point, subject to:

(a) MH receiving from MISO, pursuant to the TARIFF, 133 MW of northbound Firm Transmission Service in respect of the Northbound 133 MW US TSR as a result of the US Upgrades being constructed and place in-service.

(5) MH agrees:

(a) to use Commercially Reasonably Efforts to obtain the Firm Transmission Service referred to in Section 3.1(4)(a); and

(b) subject to Sections 3.1(1) and 3.1(4)(a), to arrange and pay for Firm Transmission Service for the delivery of the Firm Energy to be received and purchased by MH pursuant to this Agreement from the Delivery Point. Without limiting the generality of the foregoing, MH shall be responsible for the payment of any and all Market Settlement Amounts, transmission charges and associated charges, congestion charges, transmission loss charges and/or transmission energy losses, and all other charges assessed by MP's Transmission Provider for the delivery of the Firm Energy received and purchased by MH pursuant to this Agreement to the Delivery Point with the exception of those charges and amounts that MP incurs or is subject to due to arising from MP offering the Energy into the MISO market or other applicable Market (the "**MP Charges**").

(6) MP acknowledges agrees that is responsible for the payment of the MP Charges.

3.2 <u>Scheduling</u>

<u>MP's Energy</u>

(1) The Parties shall Schedule MP's Energy provided that MP's Energy that is Scheduled shall:

(a) not exceed in any hour 133 MWh per hour; and

(b) not be Scheduled during MP's Designated Peak Hours.

(2) MP shall during each day, during each month of the Contract Term, subject to the provisions of this Agreement offer into the Day-Ahead Energy and Operating Reserve Market, in accordance with the applicable MISO requirements, MP's Energy and MH shall submit a Dispatchable Interchange Schedule with a Bid into the Day-Ahead Energy Market for MP's Energy, in accordance with the applicable MISO requirements.

(3) The price at which MP offers MP's Energy pursuant to this Agreement, into the Day-Ahead Energy and Operating Reserve Market shall be at the sole discretion of MP. The price of MH's Bid for MP's Energy pursuant to this Agreement into the Day-Ahead Energy and Operating Reserve Market shall be at the sole discretion of MH.

(4) MP shall advise MH of any curtailment of MP's Energy pursuant to Section 3.6. Upon receipt of such notice, MH agrees not to submit a Bid and/or will curtail any Schedules for the amount of MP's Energy that has been curtailed and agrees to disclaim any right or entitlement to such amount of MP's Energy for the duration of the curtailment. Such curtailment time period shall decrement the Minimum MP's Energy Requested Amount for each one (1) month curtailment time period the amount determined as follows:

Minimum MP's Energy Requested Amount ÷ 240;

provided that the said monthly amount will be pro-rated for any curtailment time period that is less than one (1) month in duration.

(5) In the event during any applicable hour during the Contract Term:

(a) MH's Bid in respect of any amount of MP's Energy does not clear the Day-Ahead Energy and Operating Reserve Market; and/or

(b) any portion of MP's Energy was curtailed, restricted or reduced pursuant to Sections 3.4, 3.5 or 3.6 or Article XII,

MP shall have no obligation to sell and deliver and MH shall have no obligation to purchase and receive that quantity of MP's Energy. For greater certainty, all of the energy quantities referred to in this Section 3.2(5) shall decrement the Minimum MP's Energy Requested Amount.

(6) MP may offer MP's Energy in a manner that would enable MP to supply MP's Energy from MP's resource(s) including MP's electrical generation facility(s), third party purchases and/or Markets available to MP, and has the right to utilize any Market mechanisms that are available to MP throughout the Contract Term to satisfy its obligations under this Agreement.

(7) MH shall be responsible for and pay the costs and expenses associated with the purchase and sale of MP's Energy under the applicable OATT and/or TARIFF, including without limitation any Market Settlement Amounts, with the exception of: (i) MP Charges; (ii) all amounts arising due to MP's curtailment of MP's Energy pursuant to Section 3.6; and (iii) any costs or expenses associated with or related to the generation of MP's Energy. For greater certainty, this Section 3.2 and this Agreement does not allocate responsibility for construction, operation and maintenance costs related to the 500 kV Transmission Interconnection which will be addressed in the Canadian FCA and the US FCA.

(8) MP shall utilize the Market mechanisms authorized by the TARIFF with MP's offer in the Day-Ahead Energy and Operating Reserve Market in order to supply MH with MP's Energy under this Agreement. MH shall submit a Dispatchable Interchange Schedule with a Bid, if applicable, in accordance with the timing requirements of the Market Business Practices Manuals.

MP's Pumped Energy and MH's Stored Energy

(9) (a) MP shall submit a Financial Schedule in the Day-Ahead Energy and Operating Reserve Market for the applicable quantity of MP's Pumped Energy specifying MP as the seller and MH as the buyer. [**TRADE SECRET DATA EXCISED]**

(b) MH shall submit a Financial Schedule in the Day-Ahead Energy and Operating Reserve Market for the applicable quantity of MH's Stored Energy specifying MH as the seller and MP as the buyer. [**TRADE SECRET DATA EXCISED**]

(c) MH shall approve for MP's Pumped Energy and MP shall approve for MH's Stored Energy, if required pursuant to the Market mechanisms in effect at the applicable time, the Financial Schedule submitted by the other Party pursuant to this Section 3.2(9)(a) and (b), as applicable and each Party shall take such other actions as may be reasonably requested by the other Party pursuant to the Market mechanisms in effect at the applicable time in respect of such Financial Schedule.

(10) The Parties acknowledge that pursuant to the TARIFF MISO will: (i) charge MP and pay MH the [**TRADE SECRET DATA EXCISED**] for the quantity of MP's Pumped Energy; and (ii) charge MH and pay MP the [**TRADE SECRET DATA EXCISED**]for the quantity of MH's Stored Energy. The Parties also acknowledge that the Financial Schedules submitted in accordance with Section 3.2(9), together with: (A) MH's obligation to pay for the quantity of MP's Pumped Energy at MP's Pumped Energy Price, shall satisfy MH's obligation(s) in respect of MP's offer of MP's Pumped Energy; and (B) MP's obligation to pay for the quantity of MH's Stored Energy at MH's Stored Energy Price, shall satisfy MP's obligation(s) in respect of MH's offer of MH's Stored Energy.

(11) The Parties further acknowledge and agree that if: (i) either Party is no longer a Market Participant; or (ii) the MISO Market no longer exists; or (iii) the TARIFF no longer exists; or (iv) the TARIFF is amended or revised to the extent, that one or both of the Parties is or will be materially adversely impacted when such amendments or revisions are considered in the context of the impact they will have on the Parties continued compliance with the requirements of Sections 2.5, 3.2(9) and 3.2(10), and pursuant to Section 8.1(3) changes to Sections 2.5, 3.2(9) and 3.2(10) to address the material adverse impact such amendments or revisions to the TARIFF had on the Parties have not been developed and agreed to by the Parties; or (v) [**TRADE SECRET DATA EXCISED**] as referred to in Sections 4.1(2) and (3) is no longer available to be used in the establishment of the price for MP's Pumped Energy and MH's Stored Energy, then either Party shall on notice to the other Party have the right to immediately terminate the rights and obligations of the Parties pursuant to Section 2.5, 3.2(9) and 3.2(10), and the provisions of Sections 2.5, 3.2(9) and 3.2(10) shall no longer constitute a legally valid and binding obligation enforceable against either Party.

General

(12) As of the Effective Date, the Parties are Market Participants, and the terms of Sections 3.2(8) and 3.2(9) reflect the Scheduling practices and procedures of the TARIFF. The Parties further acknowledge that in the event that at any time after the Effective Date and prior to the end of the Contract Term: (i) either one or both of the Parties is no longer a Market Participant; or (ii) the TARIFF or the Business Practices Manuals are no longer in effect or are revised, to the extent that the requirements of Sections 3.2(8) and 3.2(9) would, if complied with by either Party, achieve a result that would be materially inconsistent with the rights and obligations of the Parties pursuant to the other provisions of this Agreement; or (iii) the MISO market no longer exists, the Parties agree that a new Scheduling mechanism that is consistent with the rights and obligations of

the Parties pursuant to this Agreement shall be established and the Parties agree to direct the Operating Committee to immediately enter into good faith negotiations to establish such new Scheduling mechanism failing which the establishment of a new Scheduling mechanism shall be determined pursuant to Article XIV on the condition that it is consistent with the rights and obligations under this Agreement prior to the revision.

(13) The Parties further acknowledge and agree that in the event that, at any time after the Effective Date and prior to the end of the Contract Term either one or both of the Parties is no longer a Market Participant and one Party is a participant in a Centrally Operated Market that is different from the Centrally Operated Market in which the other Party participates: (i) where one Party is still a participant in the MISO market, the Party that is no longer a participant in the MISO market shall pay all Seams Costs incurred by the Parties in respect of the sale and purchase and delivery of all of the energy purchased and sold pursuant to the provisions of this Agreement; and (ii) where neither Party is a participant in the MISO market the Seams Costs incurred by the Parties in respect of the sale and purchase and delivery of all of the energy purchased and sold pursuant to the provisions of this Agreement shall be accounted for and allocated equally between the Parties.

(14) The Parties further acknowledge that in the event that at any time after the Effective Date and prior to the end of the Contract Term: (i) either one or both of the Parties is no longer a Market Participant; or (ii) the TARIFF or the Business Practices Manuals are no longer in effect or are substantially revised; or (iii) the MISO market no longer exists, the Operating Committee will meet, consult in good faith, and consistent with Section 8.1(3)(d), make recommendations to the Parties about what amendments or revisions to the Agreement (if any) would be appropriate to address one or both Parties not being a Market Participant, the TARIFF changes or the end of the MISO market. The Operating Committee shall also keep a record of changes to the TARIFF that could impact on the scope and meaning of the Agreement, and consistent

with Section 8.1(3) shall make recommendations to the Parties about what amendments or revisions to the Agreement (if any) would be appropriate to address the TARIFF changes.

(15) Capitalized terms used in this Section 3.2 and not otherwise defined in this Agreement shall have the meanings prescribed in the TARIFF or the MISO Initiative Business Practices Manual for Definitions.

3.3 Transmission System Operations

The Parties acknowledge that as of the Effective Date, their respective Transmission Providers operate their transmission systems pursuant to the provisions of an OATT. Nothing in this Agreement shall obligate either Party or its respective Transmission Providers to maintain an OATT in effect during the Contract Term.

3.4 MH's Energy Curtailments

MH shall have the right to curtail, restrict, or reduce the purchase and receipt of any of MP's Energy to the extent a Force Majeure event precludes MH's ability to accept any of MP's Energy under this Agreement.

3.5 Transmission Provider Curtailments

(1) In the event that the Transmission Provider(s) of MH and/or MP reduces or curtails the Firm Transmission Service designated, allocated or required for the delivery of MP's Energy the said energy shall be curtailed, restricted or reduced in accordance with the provisions of that Transmission Provider's OATT.

(2) Subject to Section 17.3, in the event MH or MP or its respective Transmission Provider ceases to have an OATT, curtailment or reduction of energy Schedules hereunder in order to maintain the reliable operation of the interconnected AC transmission system, shall be implemented exclusively in accordance with this Section 3.5(2). Curtailment of energy deliveries under this Section 3.5(2) to accommodate such events shall be implemented as follows, in the order

specified, until the required amount of loading relief has been obtained: (a) all transmission service or transactions, that are lower in curtailment priority than Firm Transmission Service and that contribute to the condition requiring curtailment shall be curtailed first; (b) the applicable Party shall use Commercially Reasonable Efforts to cause the curtailing Person to redispatch its generation system to continue the Schedules hereunder consistent with producing the desired loading mitigation upon the congested facility(s); and (c) to the extent all transactions identified in clause (a) of this Section 3.5(2) are curtailed and system redispatch is not sufficient to produce the necessary mitigation that would avoid curtailment of the schedules under this Agreement, the transaction curtailment priority used by the applicable Transmission Provider relative to all uses of such AC transmission system at the time shall be implemented in a comparable and non-discriminatory manner.

3.6 <u>MP's Curtailments</u>

MP shall have the right to curtail, restrict or reduce the sale and supply of any of MP's Energy, in accordance with either of the following provisions:

(a) to the extent a Force Majeure precludes MP's ability to supply any of MP's Energy under this Agreement; or

(b) to the extent necessary to avoid curtailing, restricting or reducing service to MP's End-Use Load, in a manner consistent with and to the extent authorized by "Requirement 6.3 of NERC Standard EOP-002" or its successor requirements.

3.7 <u>Curtailment Notice</u>

Each Party shall provide as much notice as practicable to the other Party regarding the curtailment, restriction or reduction or refusal of the supply or acceptance, as applicable, of MP's Energy pursuant to Section 3.4 or Section 3.6. This shall include the anticipated duration of the curtailment, restriction, or reduction or refusal of the supply or acceptance, as applicable, of MP's Energy and where practicable daily updates.

ARTICLE IV

ENERGY PRICING

4.1 Energy Pricing

(1) The price for MP's Energy [**TRADE SECRET DATA EXCISED**]

(2) The price for MP's Pumped Energy [**TRADE SECRET DATA EXCISED**]

(3) The price for MH's Stored Energy [**TRADE SECRET DATA EXCISED**]

(4) [**TRADE SECRET DATA EXCISED**]

(5) [**TRADE SECRET DATA EXCISED**]

ARTICLE V

BILLING AND PAYMENT

5.1 Dollar Amounts

All dollar amounts set forth in this Agreement, monetary transactions, accounting and cost calculations between MH and MP shall be determined and stated in U.S. Dollars.

5.2 Payment in U.S. Dollars

Payment of all invoices pursuant to this Agreement shall be made in U.S. Dollars.

5.3 Method of Payment of Invoices

Payment of all invoices pursuant to this Agreement shall be made by the Party required to make the payment to the Party entitled to receive the payment by electronic bank transfer or by other mutually agreeable method(s), to the bank designated in Appendix A attached hereto. A Party may change the designation of the bank set out in Appendix A by notice to the other Party in accordance with Section 17.1 hereof. Payment shall be deemed to be made when received by the bank designated in Appendix A.

5.4 Rendering Invoices

Unless otherwise specifically agreed upon by the Parties, the calendar month shall be the standard billing period for all invoices rendered under this Agreement. As soon as practicable after the end of each calendar month, each Party shall render to the other Party an invoice for the payment obligations, if any, incurred hereunder during the preceding month.

5.5 Payment Amounts

(1) Except as hereinafter expressly provided, the amount payable by MH to MP for each month during the Contract Term shall be determined as follows:

(a) the sum of the amount determined for each applicable hour that a quantity of MP's Energy was Scheduled for that month for each applicable hour as follows:

(i) [**TRADE SECRET DATA EXCISED**]; less

(b) the sum of the amount determined for each applicable hour that a quantity of MP's Energy was curtailed, restricted or reduced pursuant to Sections 3.4, 3.5, 3.6 or Article XII that had been Scheduled during any day for that month and where a net amount was owed by MH pursuant to Section 5.5(1)(a), as follows:

(i) [**TRADE SECRET DATA EXCISED**]; plus

(c) any costs and expenses associated with the supply and receipt of MP's Energy under the applicable OATT that were billed to and paid by MP but were amounts that were required to be paid by MH pursuant to Section 3.2(7); plus

(d) the sum of the amount determined for each applicable hour that a quantity of MP's Pumped Energy was offered for that month that MH is obligated to pay for that quantity of MP's Pumped Energy pursuant to Section 3.2(9) for that month determined as follows:

(i) [**TRADE SECRET DATA EXCISED**]; less

(e) the sum of the amount determined for each applicable hour that a quantity of MH's Stored Energy was offered for that month that MP is obligated to pay for that quantity of MH's Stored Energy pursuant to Section 3.2(9) for that month determined as follows:

(i) [**TRADE SECRET DATA EXCISED**]

Provided that if during any particular month of the Contract Term the total of the amounts determined pursuant to Section 5.5(b) and (e) exceeds the total of the amounts determined pursuant to Sections 5.5(a), (c) and (d), MP shall pay MH the difference between the total of the said amounts.

5.6 Payment Date

Unless otherwise agreed by the Parties, all invoices under this Agreement shall be due and payable in accordance with each Party's invoice instructions on or before the third (3^{rd}) Business Day after receipt of the invoice. Any amounts not paid by the due date shall be deemed delinquent and shall accrue interest at the Interest Rate and such interest shall be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

5.7 Estimates

In the event that not all of the information necessary for the preparation of the monthly invoice is known in time for the preparation of the monthly invoice, estimates may be used on the monthly invoice to be followed with an adjustment to reflect actual charges on a future invoice. In the event that the amount paid or payable on any invoice or invoices delivered pursuant to this Agreement is based, in whole or in part, upon third party invoices and the third party subsequently adjusts their invoice, MP shall charge or credit MH for the change in such third party invoice within sixty (60) Business Days of MP's receipt of such adjusted third party invoice.

5.8 Billing Adjustments and Disputes

A Party may in good faith dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Agreement within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder is disputed, payment of the invoice, as invoiced, shall be required to be made when due. Notice of the objection shall be given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Upon resolution of the dispute, any required payment shall be made within ten (10) Business Days of the receipt of such resolution along with interest accrued at the Interest Rate from and including the due date to but excluding the date the payment or reimbursement is paid. Inadvertent overpayments shall be deducted by the Party receiving such overpayment from subsequent monthly invoices rendered by such Party. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 5.8 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made.

5.9 Netting

(1) The billing departments of each of the Parties shall exchange settlement data under each of the MH/MP Agreements. A netting computation of the amount that each Party has determined is due and owing under each of the MH/MP Agreements for the applicable billing period shall be performed by each of the Parties by the third (3) Business Day following the last day of each month. If the Parties are in agreement as to the net amount owing by a Party under the MH/MP Agreements, that net amount shall be paid by that Party by the date referenced in Section 5.6. If the net amount agreed upon is not paid by that date, or if the Parties are unable to agree on the net amount to be paid, all of the provisions of each of the MH/MP Agreements, including the billing and payment provisions shall continue to govern the payment obligations of each Party, and all amounts due under this Agreement shall be paid in full on the date payment is required to be made under this Agreement.

(2) The payment by a Defaulting Party of any amounts due under each of the

MH/MP Agreements shall be a condition precedent to the payment of any amounts due by the Non-defaulting Party to the Defaulting Party under either of the MH/MP Agreements.

5.10 Payment in Full

If the Parties subsequently mutually agree not to net payments pursuant to Section 5.9 or only one Party owes a debt or obligation to the other during the applicable billing period, including, but not limited to, any interest, and payments or credits, that Party shall pay such sum in full when due.

5.11 Impact of Performance Assurance

Except in connection with a termination in accordance with Article XV in which circumstances the Party benefiting from the Performance Assurance notifies the other Party in writing, amounts invoiced pursuant to this Article V shall not take into account or include any Performance Assurance which may be in effect to secure a Party's performance under this Agreement.

5.12 Accounting and Billing Procedures

The Operating Committee may make and implement decisions regarding the creation and revision, from time to time, of accounting and billing procedures necessary to implement the terms and conditions of this Agreement including the provisions of Article V.

5.13 Preliminary Billing Information

The Parties shall exchange preliminary billing information in accordance with the accounting and billing procedures established by the Operating Committee.

ARTICLE VI
GOVERNMENTAL CHARGES

6.1 Governmental Charges

Each Party shall be solely responsible for and shall pay or cause to be paid all Governmental Charges imposed on that Party in respect of any matters related to this Agreement. In the event MH is required by law or regulation to remit or pay Governmental Charges that are MP's responsibility hereunder, MP shall promptly reimburse MH for such Governmental Charges. In the event MP is required by law or regulation to remit or pay Governmental Charges that are MH's responsibility hereunder, MH shall promptly reimburse MP for such Governmental Charges. For greater certainty, the Parties agree and acknowledge that, as of the Effective Date, MP is a non-resident, non-registrant not carrying on business in Canada in respect of all supplies hereunder for Canadian federal goods and services tax purposes.

6.2 Assistance

Each Party shall provide reasonable assistance to the other Party in connection with and for the purpose of enabling due compliance with Governmental Charges and all associated information, documentation and reporting obligations. Each Party shall provide to the other and to a Governmental Authority having jurisdiction such forms, returns, reports, documents, elections, written declarations, certificates, etc. as the other Party may reasonably request, including without limitation any documentation that may be required to substantiate any available exemptions or relief from Governmental Charges.

ARTICLE VII
METERING

7.1 Metering

All applicable matters relating to the metering of MP's Energy shall be determined in accordance with the applicable provisions of agreements between the Parties Transmission Providers relating to revenue metering and the application of the provisions of such agreements shall, if necessary, be referred to the Operating

Committee.

ARTICLE VIII

OPERATING COMMITTEE

8.1 Operating Committee

(1) A committee (the "**Operating Committee**") is hereby constituted consisting of the Division Manager of Power Sales & Operations for MH or a duly authorized delegate from MH and the Vice-President Strategy & Planning for MP or a duly authorized delegate from MP. Both MH and MP shall have one vote, and all decisions of the Operating Committee must be unanimous to be effective.

(2) The Operating Committee shall meet at the written request of either of its members within ten (10) Business Days of receipt of such request. Written minutes shall be kept of all meetings and decisions and copies of such minutes shall be distributed to the Operating Committee members and the Parties within five (5) Business Days after each meeting.

(3) The Operating Committee may:

(a) make and implement decisions regarding the creation and revision, from time to time, of accounting and billing procedures necessary to implement the terms and conditions of this Agreement in accordance with Section 5.12 and Section 5.13;

(b) make and implement decisions and procedures regarding Scheduling, from time to time as necessary to implement the terms and conditions of this Agreement in accordance with Section 3.2;

(c) make and implement decisions for operating procedures for the conduct of meetings and the recording of minutes;

(d) make recommendations to the Parties concerning amendment and revision of this Agreement;

(e) perform any other obligations expressly provided for in this Agreement to be performed by the Operating Committee and any other matters as the Parties may agree from time to time;

(f) settle any controversy, claim or dispute prior to referring such matters to the Executive Officers of MP and MH for resolution in accordance with Section 14.1; and

(g) make and implement decisions concerning Section 17.1 and the form of notices being provided by the Parties pursuant to the provisions of this Agreement,

provided that the Operating Committee shall not have authority to modify the terms and conditions of this Agreement.

ARTICLE IX

REPRESENTATIONS, WARRANTIES AND COVENANTS

9.1 General and US Bankruptcy Representations and Warranties

(1) Each Party makes the following representations and warranties to the other Party, which representations and warranties will be deemed to be repeated, if applicable, by each Party throughout the Contract Term:

(a) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(b) subject to Article XI, it has all regulatory authorizations necessary for it to legally perform its obligations under this Agreement;

(c) subject to Article XI, the execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

(d) subject to Article XI, this Agreement and each other document executed and delivered in accordance with this Agreement constitutes a legally valid and binding obligation enforceable against it in accordance with its terms subject to any equitable defences;

(e) it is a Market Participant as of the date of the execution of this

Agreement;

(f) it or its Credit Support Provider, if any, is not bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it or its Credit Support Provider, if any, being or becoming bankrupt;

(g) there is not pending or, to its knowledge, threatened against it or any of its Affiliates or its Credit Support Provider, if any, any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement;

(h) it is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing and understanding the merits, and understands and accepts, the terms, conditions and risks of this Agreement. It is also capable of assuming, and assumes, the risks of this Agreement. Information and explanations related to the terms and conditions of this Agreement will not be considered advice or a recommendation to enter into this Agreement. No communication (written or oral) received from the other Party will be deemed to be an assurance or guarantee as to the expected results of this Agreement, unless such communication is expressly stated in writing to be a "guarantee" and is signed by the Party providing the statement;

(i) it has entered into this Agreement in connection with the conduct of its business and it has, subject to the provisions of this Agreement, the capacity or ability to make available or take delivery of all of MP's Energy, as applicable;

(j) the other Party is not acting as a fiduciary for or an adviser to it in respect of this Agreement;

(k) this Agreement constitutes a "master netting agreements" and all transactions pursuant to it constitute "forward contracts" within the meaning of the United States Bankruptcy Code ("**Bankruptcy Code**") or a “swap agreement” within the meaning of the Bankruptcy Code;

(l) it is a “forward contract merchant” within the meaning of the Bankruptcy Code with respect to any transactions that constitute "forward contracts" and a “swap participant” with respect to any transactions that constitute “swap agreements”;

(m) all payments made or to be made by one Party to the other Party pursuant to this Agreement constitute "settlement payments" within the meaning of the Bankruptcy Code;

(n) all transfers of Performance Assurance by one Party to the other Party under this Agreement constitute "margin payments" within the meaning of the Bankruptcy Code;

(o) it is a “master netting agreement participant” within the meaning of the Bankruptcy Code;

(p) certain provisions of this Agreement grants each Party the contractual right to "cause the liquidation, termination or acceleration" of the transactions under this Agreement within the meaning of Sections 556, 560 and 561 of the Bankruptcy Code, as they may be amended superseded or replaced from time to time;

(q) upon a bankruptcy of the other Party, a Non-defaulting Party shall be entitled to exercise its rights and remedies under this Agreement in accordance with the safe harbour provisions of the Bankruptcy Code set forth in, *inter alia*, Sections 362(b)(6), 362(b)(17), 362(b)(27), 362(o), 546(e), 548(d)(2), 556, 560 and 561, as they may be amended superseded or replaced from time to time;

(r) it is an “eligible contract participant” as defined in Section 1a(18) of the Commodity Exchange Act, as amended, 7 U.S.C. § 1a(18);

(s) it (i) is a producer, processor, or commercial user of, or a merchant handling, the commodity which is the subject of this Agreement, or the products or by products thereof; and (ii) is offered or enters into this Agreement solely for purposes related to its business as such;

(t) for the purposes of this Agreement, it is not a "utility" as such term is used in 11 U.S.C. Section 366. Each Party waives and agrees not to assert the applicability of the provisions of 11 U.S.C. Section 366 in any bankruptcy proceeding wherein such Party is a debtor. In any such proceeding, each Party further waives the right to assert that the other Party is a provider of last resort;

(u) no Event of Default or potential Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement; and

(v) all transactions under this Agreement and this Agreement itself are not "swaps" as defined in Section 1a(47)(A) of the Commodity Exchange Act, as amended, 7 U.S.C. § 1 et. seq. (the "Act"), but rather all transactions under this Agreement and this Agreement itself are excluded from the term "swap" under Section 1a(47)(B)(ii) or lawful Commodity Futures Trading Commission ("CFTC") regulations promulgated thereunder ("Regulations") as contracts of sale of nonfinancial commodities for deferred shipment or delivery intended to be physically settled. In the event that any particular transaction is deemed by an agency of competent jurisdiction (whether or not in a final adjudication) to be a "swap" as defined above, or not to be qualified for the exclusion under Section 1a(47)(B) described above, any attendant recordkeeping, reporting or other regulatory obligations shall be timely and completely fulfilled by MP; and consistent therewith, in such event, MP and MH have elected, under Section 4r(a)(3)(C) of the Act (7 U.S.C. Section 6r(a)(3)(C)), that MP shall fulfill all counterparty reporting obligations of either party under the Act and the interim and final Regulations. Notwithstanding the above, MH shall meet all its own then applicable recordkeeping obligations under the Act and interim and final Regulations (i) which are not the exclusive responsibility of MP under the Act or as provided above, and (ii) which are applicable to MH under the Act despite MH not being a U.S. person. Further, MH will cooperate in a reasonably timely and complete manner in such event to provide MP information to enable MP to meet its responsibilities under the Act.

(2) MH makes the following additional representations and warranties to MP as of the Effective Date and which will be deemed to be repeated throughout the Contract Term:

(a) no Event of Default with respect to MH and no MH Termination Event has occurred and is continuing; and

(b) no Event of Default with respect to MH and no MH Termination Event would occur as a result of its entering into or performing its obligations under this Agreement.

(3) MP makes the following additional representations and warranties to MH as of the Effective Date and which will be deemed to be repeated throughout the Contract Term:

(a) no Event of Default with respect to MP and no MP Termination Event has occurred and is continuing; and

(b) no Event of Default with respect to MP and no MP Termination Event would occur as a result of its entering into or performing its obligations under this Agreement.

9.2 MH Tax Representations and Warranties

MH makes the following representations and warranties to MP, which representations and warranties will be deemed to be repeated, if applicable, by MH throughout the Contract Term:

(a) it is a foreign person (as that term is used in section 1.6041-4(a)(4) of the United States Treasury Regulations) for United States federal income tax purposes and its U.S. Taxpayer identification number is 98-0126210; and

(b) no part of any payment received or to be received by MH in connection with this Agreement is attributable to a trade or business carried on by it in the United States of America.

9.3 MP Tax Representations

MP makes the following representations and warranties to MH, which representations and warranties will be deemed to be repeated, if applicable, by MP throughout the Contract Term:

(a) it is a "U.S. person" (as that term is used in section 1.1441-4(a) (3) (ii) of the United States Treasury Regulations) for United States federal income tax purposes and its U.S. Taxpayer identification number is 41-04181150; and

(b) no part of any payment received or to be received by MP in connection with this Agreement is attributable to a trade or business carried on by it or in respect of services rendered by it in Canada.

ARTICLE X
CONFIDENTIALITY

10.1 Confidentiality

The Parties confirm that Confidential Information (as defined in the "Non-Disclosure Agreement") had been disclosed by each Party to the other Party during the course of negotiating this Agreement and acknowledge that the provisions of the Non-Disclosure Agreement governs the disclosure of all such Confidential Information that was disclosed up to the date this Agreement is executed. The Parties (each a "**Discloser**") also recognize that there is a need pursuant to this Agreement for each Party to disclose Confidential Information, after the date this Agreement is executed, to the other Party (each a "**Recipient**") and that the provisions of this Agreement will govern the disclosure of such information not the Non-Disclosure Agreement and the Parties wish to protect the Confidential Information in the following manner and agree as follows:

(a) **"Confidential Information"** shall mean all non-public and confidential information which information is treated by the Discloser and its representatives as confidential and which is conspicuously marked "Confidential" if in written or printed form, or if oral, which is specifically identified as confidential at the time of disclosure and is confirmed in writing to each other party as "Confidential" within five (5) Business Days after disclosure, unless: (i) the information is or becomes publicly known through lawful means; (ii) the information was rightfully in Recipient's possession or part of Recipient's general knowledge prior to the date of this Agreement; or (iii) the information is disclosed to Recipient without confidential restriction by a third party who rightfully possesses the information (without confidential restriction) and did not learn of it, directly or indirectly, from Recipient.

(b) Except as hereinafter provided, Recipient shall hold all Confidential Information in strict confidence and shall not disclose any Confidential Information to any third party. Recipient shall take all reasonable measures to protect the confidentiality of, and avoid the unauthorized use, disclosure, publication, or dissemination of Confidential Information. Recipient may disclose Confidential Information:

(i) to its directors, officers, employees, members, agents or advisors, including, without limitation, its attorneys, accountants, consultants and financial advisors who need to know such information for the purposes of the transactions contemplated by this Agreement (each a "**Representative**"); and

(ii) to any other third parties, only with the prior written consent of the Discloser.

(c) If the Recipient or its Representatives are required to disclose the Confidential Information by law, regulation, ruling of a governmental agency or by court order, before the Recipient or its Representatives disclose any Confidential Information, the Recipient or its Representatives shall give the Discloser timely written notice (at least 10 Business Days) of the requirement for disclosure and assist the Discloser to secure a protective order to limit disclosure of such Confidential Information only to parties agreeing to be bound by the terms of a confidentiality agreement in a form and content satisfactory to the Discloser, acting reasonably. Recipient shall cooperate reasonably in any such efforts to secure a protective order; provided, however, Recipient shall not be required to take, or refrain from taking, any action if it would cause Recipient or its Representatives to be in violation of the terms of a required disclosure described in this Section 10.1(c).

(d) Notwithstanding the foregoing, the Parties acknowledge that if MP files this Agreement with the Minnesota Public Utilities Commission, MP agrees to seek protection of the Confidential Information in this Agreement under the Minnesota Public Utilities Commission's Minnesota Rule 7829.0500. The Parties will cooperate reasonably to prepare a public version of this Agreement for inclusion in the public record at the Minnesota Public Utilities Commission. The Parties agree that the public version of this Agreement will redact only such Confidential Information that properly constitutes proprietary information, trade secrets, or other privileged information as defined by applicable Minnesota laws.

(e) Recipient shall be liable for any use or disclosure of Confidential Information by its Representatives, which is not in compliance with the obligations imposed upon the Recipient pursuant to this Agreement.

(f) All rights, title and interest in and to the Confidential Information are reserved by, and remain the sole property of the Disclosing Party. The Recipient does not acquire any intellectual property rights under this Agreement. Nothing in this Agreement shall be construed as a grant of, or intention or commitment to grant any right, title or interest of any nature whatsoever in or to the Confidential Information.

(g) Recipient agrees that the unauthorized disclosure or use of Confidential Information could cause irreparable harm and significant injury to the Discloser, the amount of which may be difficult to ascertain or quantify, thus, making any remedy at law or in damages inadequate. Therefore, Recipient agrees that Discloser shall have the right to apply to any court of competent jurisdiction for an order restraining any breach or threatened breach of this Section and for any other relief Discloser deems appropriate. This right shall be in addition to any other remedy available to Discloser in law or equity.

(h) This Section 10.1 shall survive any termination of this Agreement for a period of three (3) years.

ARTICLE XI
CONDITIONS PRECEDENT

11.1 MH's Condition Precedent

The obligation of MH to complete the transactions referenced herein shall be subject to and contingent upon the fulfillment of the following condition precedent ("**MH's Conditions Precedent**") to the satisfaction of MH, as certified or waived in writing by MH, by the dates specified:

(a) MH obtaining the approval of its Board of Directors, within sixty (60) calendar days of the Effective Date, approving MH entering into this Agreement;

(b) the Parties executing on the Effective Date the 133 MW Energy Sale Agreement and all conditions precedent to that agreement being satisfied by the date specified in that agreement;

(c) MH receiving from MH's Transmission Provider, on or before June 1, 2025, pursuant to MH's OATT, 133 MW of northbound Firm

Transmission Service in respect of the Northbound 133 MW Canadian TSR as a result of the Canadian Upgrades being constructed and placed in-service; and

(d) MH receiving from MISO, on or before June 1, 2025, pursuant to the TARIFF, 133 MW of northbound Firm Transmission Service in respect of the Northbound 133 MW US TSR as a result of the US Upgrades being constructed and placed in-service.

11.2 MP's Condition Precedent

The obligation of MP to complete the transactions referenced herein shall be subject to and contingent upon the fulfillment of the following condition precedent ("**MP's Condition Precedent**") to the satisfaction of MP, as certified or waived in writing by MP, by the dates specified:

(a) the Parties executing on the Effective Date the 133 MW Energy Sale Agreement and all conditions precedent to that agreement being satisfied by the dates specified in that agreement.

11.3 Conditions Precedent Notices

Each Party shall notify the other Party as soon as practicable following the satisfaction or the failure to satisfy MH's Conditions Precedent or MP's Condition Precedent, as applicable.

11.4 Termination of Agreement

This Agreement shall, subject to the obligations of the Parties in Article X, terminate on the date notice has been received by one Party from the other Party that:

(a) MH's Conditions Precedent have not been satisfied and will not be waived; or

(b) MP's Condition Precedent has not been satisfied and will not be waived.

ARTICLE XII

FORCE MAJEURE

12.1 Force Majeure

(1) Neither Party shall be in breach or liable for any delay or failure in its performance under this Agreement to the extent such performance is prevented or delayed due to a Force Majeure event or circumstance, provided that:

(a) the non-performing Party shall give the other Party notice promptly (and within forty-eight (48) hours if possible) after the non-performing Party's knowledge of the commencement of the Force Majeure, with written confirmation to be supplied within ten (10) calendar days after the commencement of the Force Majeure further describing the particulars of the occurrence of the Force Majeure;

(b) the delay in performance due to the Force Majeure shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure;

(c) the Party whose performance is delayed or prevented: (i) shall proceed with Commercially Reasonable Efforts to overcome the Force Majeure which is preventing or delaying performance; and (ii) shall provide weekly written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure, the schedule for such actions and the expected date by which performance shall no longer be affected by the Force Majeure; and

(d) when the performance of the Party claiming the Force Majeure is no longer being delayed or prevented, that Party shall give the other Party notice to that effect.

(2) For greater certainty, the Parties further acknowledge that the following events or circumstances shall not constitute or form the basis for Force Majeure: (a) the loss of MH's markets; (b) MH's inability to economically use or resell MP's Energy, including MH's ability to purchase MP's Energy, at a price less than the prices provided for in this Agreement; and (c) MP's ability to sell MP's Energy

at a price greater than the prices provided for in this Agreement.

ARTICLE XIII

CREDITWORTHINESS

13.1 Credit Review Procedures

For the purpose of determining whether a Party is able to meet its obligations pursuant to this Agreement, a Party may require commercially reasonable credit review procedures. If requested by a Party, the other Party shall deliver, unless such financial statements are available on "EDGAR" or "SEDAR" or on such other Party's internet website: (a) within 150 calendar days following the end of each fiscal year, a copy of such Party's annual report containing audited consolidated financial statements for such fiscal year; and (b) within 90 calendar days after the end of each of its first three fiscal quarters of each fiscal year, a copy of such Party's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles or such other principles then in effect, provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such Party shall diligently pursue the preparation, certification and delivery of the statements.

13.2 Performance Assurances

(1) Should the creditworthiness, financial strength, or performance viability of a Party (the "**Second Party**") become unsatisfactory to the other Party (the "**Requesting Party**") in such Requesting Party's commercially reasonably exercised discretion with regard to any transaction pursuant to this Agreement, the Requesting Party may require the Second Party to post or provide at the Second Party's option: (a) a Letter of Credit; (b) other collateral or security by the Second Party that is acceptable to the Requesting Party in its commercially reasonably exercised discretion; (c) a Guarantee Agreement; or (d) some other mutually agreeable method of satisfying the Requesting Party (the items

described in (a) through (d) are referred to as "**Performance Assurance**"). The Requesting Party may only request, and the Second Party shall only be required to provide, Performance Assurance in a commercially reasonable amount under the circumstances. The Second Party may request from the Requesting Party that the Performance Assurance be returned or reduced, on the condition that such a request shall only be made once every sixty (60) days during any period when a Performance Assurance has been provided. The Requesting Party shall be required to return or reduce the Performance Assurance, after receipt of the request from the Second Party, if, considering whether the factors that justified the Requesting Party's request for Performance Assurance have been removed or improved, it is commercially reasonable to do so.

(2) Events which may cause the Requesting Party to question the Second Party's financial strength, or performance viability as set out in Section 13.2(1) above, include, but are not limited to, any of the following:

(a) The Requesting Party having knowledge that the Second Party (or its Credit Support Provider, if applicable) is failing to perform or defaulting under terms of other contracts;

(b) The Second Party, or its Credit Support Provider has an Investment Grade Credit Rating (unenhanced by unaffiliated third Party support) and the credit rating falls below an Investment Grade Credit Rating according to at least one of S&P, Moody's or DBRS;

(c) The Second Party, or its Credit Support Provider is rated BBB- by S&P (or the equivalent rating from Moody's or DBRS) and the Second Party or its Credit Support Provider (as applicable) has been either placed on negative credit watch or negative outlook by at least one such rating agency; or

(d) Other material adverse changes in the Second Party's financial condition.

(3) If the Second Party fails to provide Performance Assurance within five (5) Business Days of written demand therefore, such failure will be considered an Event of Default under Article XV of this Agreement and the Requesting Party

shall have the right to exercise any of the remedies provided for under that Article XV. Nothing contained in this Article XIII shall affect any other credit agreement or arrangement, if any, between the Parties.

(4) If the Second Party provides a Letter of Credit, the Second Party shall: (i) renew the Letter of Credit on a timely basis; and (ii) provide a substitute Letter of Credit at least twenty (20) Business Days prior to the expiration of the outstanding Letter of Credit if the issuer has indicated its intent not to renew such Letter of Credit.

13.3 <u>Grant of Security Interest</u>

(1) To secure its obligations under this Agreement and to the extent either or both Parties (or their Credit Support Provider, if applicable) deliver Performance Assurance hereunder, unless prohibited by applicable law, each Party (a "**Pledgor**") hereby grants to the other Party (the "**Secured Party**") a present and continuing security interest in, and lien on (and right of setoff against), all Performance Assurance delivered by the Pledgor to the Secured Party hereunder and held for the benefit of, such Secured Party, and all proceeds of such Performance Assurance (subject to any secured interest held or maintained by the Pledgor's lender), and Pledgor agrees to take such actions as the Secured Party reasonably requires in order to perfect the Secured Party's security interest in, and lien on (and right of setoff against), such Performance Assurance and any and all proceeds resulting there from or from the liquidation thereof.

(2) Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default, or an uncured event of default under the 250 MW System Power Sale Agreement, the Non-defaulting Party may do any one or more of the following: (a) exercise any of the rights and remedies of a Secured Party with respect to all Performance Assurance delivered by the Defaulting Party, including any such rights and remedies under law then in effect; (b) exercise its rights of setoff against any and all Performance Assurance of the Defaulting Party in the possession of the Non-defaulting Party or its agent

up to the amount then owed to it by the Defaulting Party; (c) draw on any outstanding Letter of Credit issued for its benefit up to the amount then owed to it by the Defaulting Party; and (d) liquidate all Performance Assurance then held by or for the benefit of the Secured Party, free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under this Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

(3) In addition to and not in limitation of any other right or remedy (including any right to setoff, counterclaim, or otherwise withhold payment) under applicable law, the Non-defaulting Party may, at its option and in its commercially reasonably exercised discretion and without prior notice to the Defaulting Party, setoff any amounts payable by it to the Defaulting Party under this Agreement (irrespective of currency, place of payment or booking office of obligation) against amounts that the Defaulting Party may owe it under this Agreement and the 250 MW System Power Sale Agreement. The obligations of the Parties under this Agreement in respect of such amounts shall be deemed satisfied and discharged to the extent of any such setoff.

(4) The payment by the Defaulting Party of any amounts due under this Agreement and under the 250 MW System Power Sale Agreement shall be a condition precedent to the payment of any amounts due by the Non-defaulting Party to the Defaulting Party under either of the MH/MP Agreements.

(5) The Non-defaulting Party shall use Commercially Reasonable Efforts to provide notice to the Defaulting Party as to the nature and amount of any setoff and recoupment after it is effected, but failure to give notice shall not impair the validity of any setoff.

ARTICLE XIV

DISPUTE RESOLUTION

14.1 Condition Precedent to Arbitration

Prior to initiation of arbitration, any controversy, claim or dispute between the Parties shall be first referred in writing to the Operating Committee for review and attempted resolution. If the controversy, claim or dispute is not resolved within thirty (30) calendar days after referral to the Operating Committee, the matter will be referred to the Executive Officers for review and decision. Any decision by the Executive Officers to resolve a controversy, claim or dispute must be unanimous. If the controversy, claim or dispute is not resolved within thirty (30) calendar days after referral to the Executive Officers, either Party may proceed to arbitration.

14.2 Initiation

Arbitration proceedings must be initiated within one hundred and twenty (120) calendar days of the date the controversy, claim or dispute was first referred to the Executive Officers and shall be initiated by written notice to the other Party setting forth the point or points in dispute. Unless otherwise agreed to in writing by the Parties, failure to initiate arbitration within such one hundred and twenty (120) day period shall be deemed a waiver of the right to arbitrate that controversy, claim or dispute. Provided however, that any such waiver shall not preclude a Party from initiating arbitration proceedings in respect of a similar claim, controversy or dispute based on facts that arise subsequent to the date the controversy, claim or dispute was first submitted to the Executive Officers.

14.3 Arbitration Proceedings

Subject to Section 14.1 above and Section 10.1(g), any and all controversies, claims or disputes between the Parties arising out of or relating to this Agreement or an alleged breach thereof, shall be settled by arbitration. For greater clarity and certainty, arbitration shall not be available to anyone who is not a party to this Agreement, and the aforesaid requirement to arbitrate shall not preclude a Party from seeking contribution, indemnification or damages from another Person in proceedings instituted by third parties in courts of competent jurisdiction. Unless otherwise provided in this Article, the arbitration shall be conducted before three arbitrators and shall be conducted in accordance with the International Commercial Arbitration Act (Ontario), RSO 1990, c.I9 and the UNCITRAL model Law on International Commercial Arbitration as amended and then in effect. Each Party shall select one arbitrator, and the two selected arbitrators shall jointly agree, within 30 days after the last of the two arbitrators have been appointed, on a third arbitrator who shall chair the arbitration. All arbitrators shall be competent by virtue of education and experience in the particular matter subject to arbitration. Before proceeding with the first hearing, each arbitrator shall take an oath of office. The arbitrators shall require witnesses to testify under oath administered by a duly qualified person. The arbitrators shall have jurisdiction and authority only to interpret, apply or determine compliance with the provisions of this Agreement insofar as shall be necessary to determine the particular matter subject to arbitration. The arbitrators shall not have jurisdiction or authority to add to, detract from, or alter the provisions of this Agreement or any applicable law or rule of civil procedure. The arbitrators shall have the power to order specific performance under any and all provisions of this Agreement and no Party can avoid specific performance based on an argument that the other Party has an adequate remedy at law. All arbitrations shall be held in Winnipeg, Manitoba.

14.4 <u>Jurisdiction</u>

The arbitrators may rule on their own jurisdiction, including any objections with respect to the existence or validity of this Agreement. For that purpose, this Article shall be treated as an agreement independent of the terms of the balance of this Agreement. A decision by the arbitrators that this Agreement is null and void shall not entail *ipso jure* the invalidity of this Article. If a Party disputes the authority or jurisdiction of the arbitrators, it shall notify the other Party as soon as the matter alleged to be beyond the authority or jurisdiction of the arbitrators is raised during the arbitration proceedings.

The arbitrators may rule on the issue as to whether or not they have the authority or jurisdiction in dispute, either as a preliminary question or in an award on the merits.

14.5 Discovery

Each Party shall have the rights of discovery in accordance with the applicable rules of the Court of Queen's Bench of Manitoba. All issues subject to discovery shall be determined by order of the arbitrators upon motion made to them by any Party. When a Party is asked to reveal material which the Party considers to be proprietary or confidential information or trade secrets, the Party shall bring the matter to the attention of the arbitrators who shall make such protective orders as are reasonable and necessary or as otherwise provided by law.

14.6 Continuation of Performance

Pending the final decision of the arbitrators, the Parties agree, subject to Section 15.2, to diligently proceed with the performance of all obligations, including the payment of all sums required by this Agreement. Payment of any interest shall be as determined by the arbitrator.

14.7 Costs

All fees, costs and expenses of the arbitrators incurred in connection with the arbitration shall be allocated among the Parties by the arbitrators. The nature of the dispute and the outcome of the arbitration shall be factors considered by the arbitrators when allocating such fees, costs, and expenses. Each Party shall be responsible for the fees, costs, and expenses of its own employees, expert consultants and attorneys, and for the costs of exhibits and other incidental costs.

14.8 Enforcement

Any decision (including orders arising out of disputes as to the scope or appropriateness of a request for, or a response to, discovery) of an arbitrator may be enforced in a court of competent jurisdiction with all costs, including court costs and attorney's fees and disbursements, paid by the Party found to be in default or in error. Judgment upon the award rendered by the arbitrators may be entered in any court of competent jurisdiction and may be enforced in accordance with the Convention on the Recognition and Enforcement of Foreign Arbitral Awards.

14.9 <u>Correction and Interpretation of Award</u>

Within thirty (30) calendar days after receipt of an arbitration award, a Party, with notice to the other Party, may request the arbitrators to correct in the award any errors in computation, any clerical or typographical errors or any errors of similar nature, or may request the arbitrators to give an interpretation of a specific point or a part of the award. If the arbitrators consider the request to be justified, they shall make the correction or give the interpretation within thirty (30) calendar days after receipt of the request. The interpretation shall form part of the award. The arbitrators may correct any error as herein-before referred to on their own initiative within thirty (30) calendar days after the date of award. In addition, within thirty (30) calendar days after receipt of an award, a Party with notice to the other Party may request the arbitrators to make an additional award as to claims presented in the arbitration but omitted from the award. If the arbitrators consider the request to be justified, they shall make an additional award within sixty (60) calendar days after receipt of the request. The arbitrators may extend, at their sole discretion if necessary, the period of time within which it shall make a correction, interpretation or an additional award.

ARTICLE XV

DEFAULT/TERMINATION

15.1 <u>Events of Default</u>

If any of the following events, conditions, or circumstances (each an "**Event of Default**") shall occur and be continuing:

(a) the failure of either Party or any Credit Support Provider of either Party to make any payment to the other Party as required by this Agreement if such amount remains unpaid for a period of five (5) Business Days after the date the Defaulting Party receives written notice from the Non-defaulting Party that the amount is overdue;

(b) the failure by either Party to perform or observe any material obligation to the other Party under this Agreement, that is not excused by an event of Force Majeure, other than obligations for the payment of money, if such failure is not remedied within thirty (30) calendar days after written notice thereof shall have been given by the Non-defaulting Party to the Defaulting Party;

(c) the insolvency or bankruptcy of a Party or its Credit Support Provider or its inability or admission in writing of its inability to pay its debts as they mature, or the making of a general assignment for the benefit of, or entry into any contract or arrangement with, its creditors;

(d) the application for, or consent (by admission of material allegations of a petition or otherwise) to, the appointment of a receiver, trustee or liquidator for a Party or for all or substantially all of its assets, or its authorization of such application or consent, or the commencement of any proceedings seeking such appointment against it without such authorization, consent or application, which proceedings continue undismissed or unstayed for a period of thirty (30) calendar days;

(e) the authorization or filing by a Party or its Credit Support Provider of a voluntary petition in bankruptcy or application for or consent (by admission of material allegations of a petition or otherwise) to the application of any bankruptcy, reorganization, readjustment of debt, insolvency, dissolution, liquidation or other similar law of any jurisdiction or the institution of such proceedings against a Party or its Credit Support Provider without such authorization, application or consent, which proceedings remain undismissed or unstayed for thirty (30) calendar days or which result in adjudication of bankruptcy or insolvency within such time;

(f) in the event that a Party fails to provide Performance Assurance within five (5) Business Days of the date the Performance Assurance was to have been provided in accordance with Section 13.2;

(g) a Party or its Credit Support Provider consolidates or amalgamates with, or merges with or into, or transfers all or substantially all its assets to or reorganizes or reincorporates or reconstitutes into or as another entity and, at the time of such consolidation, amalgamation, merger, transfer, reorganization, reincorporation or reconstitution, the resulting, surviving or transferee entity fails to assume, if applicable, all the obligations of such Party or such Party's Credit Support Provider under this Agreement to which it or its predecessor was a party and, in the case of a Credit Support Provider, such Party has failed to provide a replacement Guarantee Agreement (if a Guarantee Agreement is outstanding) within five (5) Business Days;

(h) the occurrence of a Letter of Credit Default that remains uncured for five (5) Business Days;

(i) the occurrence of an uncured "Event of Default" (as such term is defined in Section 17.1 of the 250 MW System Power Sale Agreement) provided that the Non-defaulting Party shall have the unfettered discretion whether to declare an Event of Default under this Agreement associated with such occurrence;

(j) the occurrence of an uncured "Event of Default" (as such term is defined in Section 15.1 of the Energy Exchange Agreement) provided that the Non-defaulting Party shall have the unfettered discretion whether to declare an Event of Default under this Agreement associated with such occurrence;

(k) the occurrence of an uncured "Event of Default" (as such term is defined in Section 17.1 of the 133 MW Energy Sale Agreement) provided that the Non-defaulting Party shall have the unfettered discretion whether to declare an Event of Default under this Agreement associated with such occurrence; or

(l) any material representation or warranty made by the Defaulting Party in this Agreement that is proven to have been false in any material respect when made,

then, and in any such event, the Non-defaulting Party shall have all the rights and remedies available to it at law or in equity, including the right to terminate this Agreement by written notice to the Defaulting Party in accordance with Section 15.3.

15.2 Suspension of Performance

Notwithstanding any other provision of this Agreement, if an Event of Default has occurred and is continuing beyond any applicable cure period, the Non-defaulting Party, upon notice to the Defaulting Party, shall have the right: (a) to suspend performance under this Agreement; provided, however, in no event shall any such suspension continue for longer than (10) Business Days unless an Early Termination Date has been declared and notice thereof given pursuant to Section 15.3; and (b) to the extent an Event of Default has occurred and is continuing beyond any applicable cure period, to exercise any remedies available at law or in equity.

15.3 Right to Terminate Following an Event of Default

(1) If at any time an Event of Default with respect to a Party (the "**Defaulting Party**") has occurred and is then continuing beyond any applicable cure period, the other Party (the "**Non-defaulting Party**") may, by not less than twenty (20) calendar days notice to the Defaulting Party specifying the relevant Event of Default, designate a Business Day not earlier than the day such notice is effective as termination of this Agreement prior to the expiry of the Contract Term (such designated Business Day will constitute an "**Early Termination Date**").

(2) In addition to and not in limitation of any other right or remedy (including any right to setoff, counterclaim, or otherwise withhold payment) available to the Non-defaulting Party at law or in equity, the Non-defaulting Party may, at its

option and in its commercially reasonably exercised discretion and without prior notice to the Defaulting Party, setoff any amounts payable by it to the Defaulting Party under this Agreement (irrespective of currency, place of payment or booking office of obligation) against amounts that the Defaulting Party may owe it under the 250 MW System Power Sale Agreement. The obligations of the Parties under this Agreement in respect of such amounts shall be deemed satisfied and discharged to the extent of any such setoff and recoupment.

(3) The payment by the Defaulting Party of any amounts due under either of the MH/MP Agreements shall be a condition precedent to the payment of any amounts due by the Non-defaulting Party to the Defaulting Party under either of the MH/MP Agreements.

(4) The Non-defaulting Party shall use Commercially Reasonable Efforts to provide notice to the Defaulting Party as to the nature and amount of any setoff and recoupment after it is effected, but failure to give notice shall not impair the validity of any setoff and recoupment.

15.4 MH Termination Events

MH has the right, but not the obligation, to terminate this Agreement (a "**MH Termination Event**") immediately upon notice to MP upon the termination of any of the MH/MP Agreements prior to the expiry of the term of the applicable agreement, unless the termination occurred due to occurrence of an uncured Event of Default (as such term is defined in the applicable agreement) by MH.

15.5 MP Termination Events

MP has the right, but not the obligation, to terminate this Agreement (a "**MP Termination Event**") immediately upon notice to MH upon the termination of the MH/MP Agreements prior to the expiry of the term of the applicable agreement, unless the termination occurred due to occurrence of an uncured Event of Default (as such term is defined in the applicable agreement) by MP.

15.6 Payment on Termination

On or as soon as practicable following the effective designation of either an MH Termination Event or an MP Termination Event, MH shall calculate the amounts due and owing by MP to MH, and MP shall calculate the amounts due and owing by MH to MP, as applicable, for the period up to and including the termination date, and each Party shall deliver an invoice to the other Party for the amount due which shall be payable in accordance with Article V.

ARTICLE XVI
LIMITATION OF LIABILITY

16.1 **Limitation of Liability**

THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF THE EXPRESS REMEDY OR MEASURE OF DAMAGES PROVIDED IS ALL RIGHTS OR REMEDIES AVAILABLE TO A PARTY AT LAW OR IN EQUITY, SUCH PARTY SHALL BE ENTITLED TO SEEK ALL OR ANY SUCH RIGHTS AND DAMAGES OR REMEDIES. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED IN THIS AGREEMENT, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL

TRADE SECRET DATA EXCISED

OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE XVII
GENERAL

17.1 <u>Notices</u>

Any notices, demands or requests (other than those operational matters identified by the Operating Committee), required or authorized by this Agreement shall be in writing and may be delivered by hand delivery, mail, electronic mail, confirmed fax, or overnight courier service to:

if to the Manitoba Hydro-Electric Board:

Division Manager
Power Sales & Operations
Manitoba Hydro
360 Portage Avenue
Post Office Box 815

Winnipeg, Manitoba
R3C 2P4
Fax (204)-360-6137

with copies to:

General Counsel
Manitoba Hydro
360 Portage Avenue
Post Office Box 815
Winnipeg, Manitoba
R3C 2P4
Fax (204)-360-6147

if to Minnesota Power:

Vice-President Strategy & Planning
Minnesota Power
30 West Superior St.
Duluth, MN 55802
Fax (218) 723-3915

with copies to:

General Counsel
Minnesota Power
30 West Superior Street
Duluth, MN 55802
Fax (218) 723-3955

Notice by hand delivery shall be effective at the close of business on the day actually received, if received during the recipient's business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight mail, or courier, shall be effective on the next Business Day after it was sent. Notice by electronic mail or confirmed fax shall be effective at the close of business on the day actually received, if received during the recipient's business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. The designation of the persons to be notified or the address of such persons may be changed at any time by similar notice.

17.2 Operational Matters

All issues related to operational matters and notices in respect thereto, as identified by the Operating Committee shall be directed to the appropriate operations personnel at MH and MP. Each Party shall each provide to the other Party a list of contacts for notification on the said operational matters that shall be updated from time to time as required.

17.3 MH's Marketing and Sales Function and MP's Merchant Function

The Parties acknowledge that MH has established an open access transmission tariff and MP is subject to the TARIFF, and MH has adopted, and MP is subject to, the FERC "Standards of Conduct" which require that MH's and MP's respective employees engaged in transmission system operations function independently from MH's and MP's respective marketing and sales employees, and that MH and MP treat all of their respective transmission customers on a non-discriminatory basis. This Agreement is entered into by MH and MP on behalf of their respective marketing and sales functions. Nothing in this Agreement shall obligate either MH's or MP's transmission function to take or refrain from taking any action.

17.4 Records

Each Party shall keep complete and accurate records and memoranda of its operations hereunder and shall maintain such data as may be necessary to determine with reasonable accuracy any item required hereunder. With respect to invoicing records, each Party shall maintain such records, memoranda and data for the current calendar year plus a minimum of five (5) previous calendar years. Each Party or its respective designee, shall each have the right, at its sole expense, upon reasonable prior notice during the other Party's regular business hours at such Party's primary place of business, to inspect, review and take copies of the other Party's records as far as such records concern monetary matters or other issues under this Agreement and may be reasonably necessary for the purpose of ascertaining the reasonableness and accuracy of any statements of cost, bills or invoices relating to transactions hereunder. Each Party shall treat and shall take reasonable steps to cause its designee to treat such information so inspected, reviewed, or copied as Confidential Information.

17.5 <u>Indemnity</u>

(1) Each Party shall indemnify and save harmless the other Party from and against all claims, actions, suits, proceedings, demands, assessments, judgments, charges, penalties, costs, and expenses which arise or are made or claimed against or suffered or incurred by the other as a result of:

(a) any breach by it of or any inaccuracy of any representation or warranty contained in this Agreement or in any agreement, instrument, certificate or other document delivered pursuant hereto; and

(b) any breach or non-performance by it of any covenant to be performed by it that is contained in this Agreement or in any agreement, certificate or other document delivered pursuant hereto.

(2) The Parties agree:

(a) MP shall be deemed to be in exclusive control of the MP's Energy prior to the delivery by MP and receipt by MH of MP's Energy at the Delivery Point and MP shall be responsible for, and shall indemnify MH from, any damages or injury MH or any third party may suffer or incur, caused thereby except to the extent such damages or injury were caused by the gross negligence or wilful misconduct of MH; and

(b) MH shall be deemed to be in exclusive control of MP's Energy from and after delivery by MP and receipt by MH of MP's Energy at the Delivery Point and shall be responsible for, and shall indemnify MP from, any damages or injury MP or any third party may suffer or incur, caused thereby except to the extent such damages or injury is caused by the gross negligence or wilful misconduct of MP.

For the purposes of this Section 17.5(2) "gross negligence or wilful misconduct" does not include acts or omissions by a Party that constitute ordinary negligence, and "damages or injury" does not include indirect, incidental, and consequential damages, and without restricting generality of the foregoing, "damages or injury" does not include expenses or liabilities associated with the interruption of power, energy or related services to any third Person.

(3) Each Party shall promptly notify the other Party of claims, demands or actions that may result in a claim for indemnity. Failure to be provided with notice will not relieve a Party from indemnification liability unless, and then only to the extent that, such failure results in the forfeiture by such Party of a substantial right or defense. No settlement of any claim which may result in a claim for indemnity may be made by either Party without the prior consent of the other Party, which consent may not be unreasonably withheld. Neither Party shall be liable under this Agreement in respect of any settlement of a claim unless it has consented in writing to such settlement.

17.6 Governing Law

(1) In respect of matters under this Agreement relating to or arising out of the sale of MP's Energy and MP's Pumped Energy, the Parties acknowledge that those matters and the applicable provisions of this Agreement concerning same shall be governed and construed in accordance with the laws of the state of Minnesota and United States. Any disputes arising under this Agreement that are not resolved by arbitration shall be subject to the exclusive jurisdiction of the courts of the state of Minnesota and the Supreme Court of the United States.

(2) In respect of matters under this Agreement relating to or arising out of the offering and all other matters in respect of the MH's Stored Energy, the Parties acknowledge that those matters and the applicable provisions of this Agreement concerning same shall be governed and construed in accordance with the laws of

the province of Manitoba and Canada. Any disputes arising under this Agreement concerning same that are not resolved by arbitration shall be subject to the exclusive jurisdiction of the courts of the province of Manitoba and the Supreme Court of Canada.

17.7 Waiver of Right to Trial by Jury

Each Party hereby irrevocably waives to the fullest extent permitted by applicable law, any and all rights it may have to trial by jury with respect to any legal proceeding arising out of or relating to this Agreement and any agreement executed or contemplated to be executed in conjunction with this Agreement. This provision is a material inducement to each of the Parties for entering into this Agreement. Each Party hereby waives any right to consolidate any action, proceeding, or counterclaim arising out of or in connection with this Agreement and any other agreement executed or contemplated to be executed in conjunction with this Agreement, or any matter arising hereunder or thereunder in which a jury trial has not or cannot be waived.

17.8 Foreign Sovereign Immunities Act

MH irrevocably agrees to waive the protections of the Foreign Sovereign Immunities Act, 28 U.S.C. §1602, et seq., in connection with this Agreement.

17.9 No Representation or Warranty for Injury

It is acknowledged and agreed that MP's Energy and related services are inherently dangerous, MP offers no warranty, or representation, express or implied, that MP's Energy or related services will not cause injury to Person, property or business.

17.10 Surviving Termination

All provisions of this Agreement which by their nature are intended to survive the termination of this Agreement, including, the provisions relating to: (a) the billing by MP to MH of and payment from MH to MP for or related to MP's Energy and MP's

Pumped Energy; (b) the billing by MH to MP of and payment from MP to MH for or related to MH's Stored Energy; (c) the confidentiality provisions pursuant to Article 10 of this Agreement; and (d) Section 17.5, shall survive the Contract Term or the earlier termination of this Agreement as the case may be for a period of three (3) years following the expiration of the Contract Term or the earlier termination of this Agreement.

17.11 Enurement

This Agreement shall be binding upon and its benefits enure to the Parties and their permitted successors and assigns. This Agreement shall not create the relationship between the Parties of a joint venture or a partnership.

17.12 Assignment

Neither this Agreement nor any interest or obligation in or under this Agreement may be assigned (whether by way of security or otherwise) by either Party without the prior written consent of the other Party, except that either Party may, without consent of the other Party, assign this Agreement (in whole and not in part only) to any of their respective Affiliates, including any newly formed Affiliate pursuant to either Party reorganizing its corporate structure, on sixty (60) calendar days advance notice to the other Party provided that:

(a) prior to the effective date of the assignment, Performance Assurance, if required by the non-assigning Party, has been provided to the non-assigning Party in an amount and upon terms satisfactory to the non-assigning Party, in its sole discretion, acting reasonably;

(b) the non-assigning Party shall not be required to pay to the assignee an amount in respect of any Governmental Charges which the non-assigning Party would not have been required to pay to the assigning Party in the absence of such assignment;

(c) the non-assigning Party shall not receive a payment from which an amount has been withheld or deducted, on account of a withholding tax in excess of that which the assigning Party would have been required to so withhold or deduct in the absence of such assignment;

(d) it does not become unlawful for either Party or the assignee to perform any obligation under this Agreement as a result of such assignment; and

(e) no Event of Default or MH Termination Event or MP Termination Event, as applicable, occurs as a result of such assignment.

With respect to the results described in clauses (b) and (c) above, the non-assigning Party will cause the assignee to make, and the assigning Party will make, such reasonable representations as may be mutually agreed upon by the assigning Party, the assignee and the non-assigning Party in order to permit such parties to determine that such results will not occur upon or after the assignment.

17.13 Waiver and Amendment

Unless otherwise specifically provided herein, this Agreement may be altered, modified, varied, or waived, in whole or in part, only by a supplementary written document executed by the Parties.

17.14 Counterparts

This Agreement may be executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

17.15 Recording of Communications

The Parties agree: (a) that each may electronically monitor or record, at any time and from time to time, any and all communications between them; (b) to waive any further notice of such monitoring or recording; (c) to notify and obtain any necessary consents of its officers and employees of such monitoring or recording; (d) that any such monitoring or recording may be offered into evidence in any such suit, trial, hearing, arbitration, or other proceeding; and (e) to furnish appropriately redacted copies of recordings to the other Party within ten (10) Business Days of the other Party's written request.

17.16 Existing Agreements

Each of the Parties are parties to existing agreements with each other and with other third parties. This Agreement shall not affect the obligations and rights of a Party with respect to such existing agreements, except as expressly provided for herein.

17.17 No Other Rights

This Agreement is not intended to and shall not create rights of any character whatsoever in favour of any Person, other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, nor is anything in this Agreement intended to relieve or discharge the obligation or liability of any third Persons to any Party, nor shall any provision of this Agreement give any third Persons any right of subrogation or action over against any Party.

17.18 Entire Agreement

Subject only to the provisions of the Non-Disclosure Agreement, this Agreement represents the entire agreement between the Parties with respect to the subject matter hereof and supersedes all prior oral and written proposals and communications pertaining hereto, including the Term Sheet. There are no representations, conditions, warranties or agreements, express or implied, statutory or otherwise, with respect to or collateral to this Agreement other than contained herein or expressly incorporated herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed on the date first above written.

THE MANITOBA HYDRO-ELECTRIC BOARD

____

TRADE SECRET DATA EXCISED

By: A.D. Cormie, Division Manager Power Sales & Operations

I HAVE AUTHORITY TO BIND THE MANITOBA HYDRO-ELECTRIC BOARD

MINNESOTA POWER, an operating division of ALLETE, Inc.

____

By: Alan R. Hodnik, Chairman, President and Chief Executive Officer

I HAVE AUTHORITY TO BIND ALLETE, INC.

APPENDIX A

INTERBANK TRANSFER OF FUNDS ACCOUNT DESIGNATIONS

For THE MANITOBA HYDRO-ELECTRIC BOARD:

US Dollar Wire Payments

[TRADE SECRET DATA EXCISED]

For MINNESOTA POWER

US Dollar Payments

[TRADE SECRET DATA EXCISED]

Appendix B

[TRADE SECRET DATA EXCISED]