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OTTER TAIL POWER COMPANY

September 17, 2010

Dr. Burl Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

PUBLIC DOCUMENT - TRADE SECRET AND PRIVILEGED DATA EXCISED

RE: IN THE MATTER OF OTTER TAIL POWER COMPANY'S 2011-2025 RESOURCE PLAN, DOCKET NO. E017/RP-10-623

Dear Dr. Haar:

On August 27, 2010 Otter Tail Power Company ("Otter Tail") advised the Commission that it would be filing an update to its 2010 Resource Plan Filing.

Enclosed please find fifteen (15) copies of the update and a Certificate of Service. Also enclosed is the original document as an unbound single-sided copy of the filing pursuant to the DPS/PUC letter dated May 28, 1996 requesting such copies.

Copies of the update have been served upon all persons on the service list. The company's website will be updated as well.

Pages three and four of "Appendix F" contain confidential business information that is considered proprietary. These sections have been marked with the caption "Non-Public Information" to indicate "Trade Secret Information" according to Minn. Stat. Sec. 13.37, subd. 1(b). This statute protects certain "government data" as that term is defined at Minn. Stat. Sec. 13.02, subd. 7, from being disclosed by an administrative agency to the public. The information being supplied is considered to be a "compilation" of data that, (1) was supplied by Otter Tail, (2) is the subject of reasonable efforts by Otter Tail to maintain its secrecy, and (3) derives independent economic value, actual or potential, from not being general known to or accessible to the public.

Otter Tail respectfully requests that the Commission approve its 2011 – 2025 Resource Plan.

Should you have any questions, please contact me at (218) 739-8417.

Sincerely,

/s/ BRIAN DRAXTEN
Brian Draxten
Manager, Resource Planning

wao
Enclosures
By electronic service and U.S. Mail
c: Service Lists

CERTIFICATE OF SERVICE

RE: IN THE MATTER OF OTTER TAIL POWER COMPANY'S SUBMITTAL OF ITS 2011-2025 RESOURCE PLAN, DOCKET NO. E017/RP-10-623

I, Wendi A. Olson, hereby certify that I have this day served a copy of the following, or a summary thereof, on Dr. Burl W. Haar and Sharon Ferguson by e-filing and First Class mail, and to all other persons on the attached service lists by electronic service or by First Class mail.

Otter Tail Power Company
2011-2025 Resource Plan Update

Dated this **17th** day of **September, 2010**.

/s/ WENDI A. OLSON
Wendi A. Olson, Regulatory Assistant
Otter Tail Power Company
215 South Cascade Street
Fergus Falls MN 56537
(218) 739-8699

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STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Otter Tail Power Company's 2011-2025 Resource Plan

Docket No. E017/RP-10-623

NOTICE OF CHANGE OR CORRECTION

PROCEDURAL HISTORY

On June 25, 2010, Otter Tail Power Company ("Otter Tail" or the "Company") submitted its Resource Plan for 2011-2025 for Commission approval pursuant to Minn. Stat. § 216B.2422 and Minn. Rules Chapter 7843. On August 27, 2010, the Company filed a letter with the Commission stating its intention to file an update to its 2011-2025 Resource Plan no later than September 17, 2010.

INTRODUCTION

After the Company filed its Resource Plan on June 25, 2010, the Company received certain updated cost information and discovered four additional, necessary corrections. The purpose of this filing is to change and correct pages of previously filed Resource Plan. The updated cost information and corrections to the original filing include the following:

1. Updated the cost of the Big Stone Plant Air Quality Control System Project.
2. Corrected the capital cost of the aeroderivative simple cycle, natural gas-fired combustion turbine selected in 2014 in the Strategist model.
3. Corrections in Appendix B to data for the Coyote Station and Hoot Lake units 2 and 3: Minnesota Electric Utility Annual Report, 7610.0430 Fuel Requirements and Generation by Fuel Type.
4. Correction of costs for Coyote O&M expenses originally included in the Strategist model.
5. Correction of the NSP energy contract included in the Strategist model as part of market purchases, rather than as a separate contract with specified terms.

CHANGES/CORRECTIONS

A description of each change/correction is included below.

1. <u>Big Stone Plant Air Quality Control System (AQCS)</u>

Beginning in 2010, the Company began a more detailed study effort to review the necessary upgrades to reduce emissions at Big Stone Plant in compliance with South Dakota's Regional Haze State Implementation Plan. This study effort is meant to review technology choice, feasibility, equipment arrangement, capital and O&M costs, and a likely project schedule. On August 13, 2010, Otter Tail began receiving preliminary results of an on-going study effort on the installation cost of the AQCS at Big Stone Plant.

In the original Resource Plan filing, Otter Tail used $300 million as the total capital cost of the AQCS project (Otter Tail's share of Big Stone Plant ownership is 53.9%). The figures were based on general capital cost guidelines provided by the U.S. Environmental Protection Agency.

The estimates provided as part of the Company's current on-going study effort were just less than $400 million with an accuracy of -15% / +25%. For the new scenario runs now being submitted, the Company used the high cost estimate of $500 million ($400 million + 25%) for the AQCS project and re-ran all 22 scenarios.

Obviously, the Net Present Value of Revenue Requirements (NPVRR) for all scenarios increased. Seven of the scenarios had a slightly different combination or timing of new resources. However, only one scenario ("Spot Market Reliance") did not choose the Big Stone Plant AQCS project as a part of the least cost plan.

2. Corrected the capital cost of the aeroderivative simple cycle, natural gas-fired combustion turbine selected in 2014.

The capital cost of the aeroderivative simple cycle, natural gas-fired combustion turbine selected in 2014 was incorrectly included in the Strategist model at $700/kW. That cost should have been $1000/kW including transmission. This correction was included in each of the 22 Strategist scenarios.

3. Corrections in Appendix B: Minnesota Electric Utility Annual Report

The capacity factor and forced outage rate for Coyote Station and the forced outage rates for Hoot Lake units 2 and 3 were incorrect in the original filing. The values have been corrected in the revised sheets. This correction did not require changes in the Strategist model.

4. ~~Correction of costs for Coyote O&M expenses originally included in the Strategist model~~

O&M costs were entered incorrectly in the Strategist model beginning in 2017. This correction was included in each of the 22 Strategist scenarios.

5. Inclusion of the NSP energy contract in the Strategist model as part of market purchases, rather than as a separate contract with specified terms.

The NSP energy contract was ignored by the model and the energy was included in the market purchases at the forecasted market price. The model was corrected to represent the NSP energy contract according to the specified terms. This correction was included in each of the 22 Strategist scenarios.

INSERTION OF CORRECTED PAGES INTO OTTER TAIL'S RESOURCE PLAN FILING

Included in this filing are corrected pages of Otter Tail's Resource Plan filing. All pages are three-hole punched for insertion into the three-ring binder provided earlier. Each corrected page is marked: "**Revised 9-17-2010.**"

- Replace the entire "Section 2: Resource Plan Non-Technical Summary" with the corrected replacement provided.
- Replace the entire "Section 5: Preferred Resource Plan" with the corrected replacement provided.
- Appendix B: Replace the first two pages of 7610.0430 Fuel Requirements and Generation by Fuel Type with the corrected replacements provided.
- Appendix F: Replace page 3-4 with the corrected replacement provided.

Using the updated Strategist data, Otter Tail will update the information requested by the OES in its information request numbers 1 and 2.

Summary

Otter Tail has changed and corrected its 2011-2025 Resource Plan to reflect certain updated cost information and make four additional, necessary corrections. The results reflect an up-to-date assessment of the Company's least cost plan under base case assumptions and sensitivity studies. The Company's preferred plan did not change from the preferred plan in its original filing.

Should you have any questions regarding this submittal, please contact me at 218-739-8417 or via email at bhdraxten@otpco.com.

/s/ BRIAN DRAXTEN
Brian Draxten
Manager, Resource Planning

Revised 9-17-2010

Section 2

Resource Plan Non-Technical Summary

This section replaces the original section 2

Revised 9-17-2010

2 Resource Plan Non-Technical Summary

Otter Tail respectfully submits this resource plan filing to the Minnesota Public Utilities Commission (Commission) for approval under MN Statute §216B.2422 and MN Rules Part 7843. The plan identifies the anticipated electric service needs of the Company's customers for the 2011-2025 planning period. The plan details specific action items that Otter Tail intends to complete within the first five years of the planning period as part of the plan implementation.

The Commission has previously stated that it considers the characteristics of the available resource options and the proposed plan as a whole. In addition, Otter Tail understands the Commission evaluates resource plans on their ability to:

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

Otter Tail has worked diligently to keep these objectives in mind while developing this resource plan. Otter Tail continues to place emphasis on making existing facilities as efficient and economical as is cost-effective. These efforts should help to maintain low rates and customer bills, reduce the financial risks of future environmental regulation or taxes, reduce the environmental effects, and keep the Company well positioned to respond to change. But existing resources alone cannot meet future customers' needs. This resource plan provides a blend of supply-side and demand-side resource options to meet those customer needs.

Load Forecast

The process of developing this resource plan filing began with the development of an econometric load forecast, which provided a base case scenario, a low load growth scenario and a high load growth scenario.

The forecast energy and demand requirements are detailed in Appendix B. The energy requirements forecast represents an approximate 1.66% annual growth rate, prior to new demand side management (DSM) programs, and is the key component in determining the type of capacity resources that are added, whether baseload, intermediate, or peaking. Load growth through 2017 is driven significantly by specific large expansion plans by customers. Peak demands are anticipated to average an annual growth rate of 1.79% in the summer and 1.58% in the winter, prior to new DSM programs. The peak demand will determine the magnitude of capacity resources that are required for the system. As a participant in the Midwest Independent Transmission System Operator (Midwest ISO), Otter Tail is currently required to maintain a 4.50% reserve margin on the forecasted peak demand in each month, after accounting for plant accreditation ratings as defined by the Midwest ISO. Failure to meet this obligation for each planning month could result in a significant financial penalty of about $90,000 per megawatt of capacity deficiency.

Future Resource Needs

Tables 2-1 and 2-2 provide the Company's summer and winter resource needs, respectively, showing the Company's projected load and capability according to Midwest ISO Module E rules for resource adequacy. Please see Section 3 for discussion of Midwest ISO Module E and further detail regarding the resource adequacy obligation calculation. [1]

The 50th- percentile demand forecast is adjusted for accredited demand response capability and a 4.50% reserve requirement is calculated on this net demand forecast to determine the expected resource adequacy obligation. The total accredited capacities, shown as Planning Resource Credits (PRCs), represent the Midwest ISO's capacity ratings for the Company's resources based on the 2010 Planning Year accreditation levels. Aggregate PRCs are the accreditation of those resources that have deliverability anywhere within the Midwest ISO footprint. Local PRCs are the accreditation of those resources that are Behind-the-Meter-Generation, or locally deliverable to the Company's load. Capacities for transactions are shown separately. Resource accreditations are based on historical summer performance and do not vary monthly. Transactions and demand response accreditations, however, can vary monthly.

Table 2-1: Summer 2010-2025 Base Case Projected Load and Capability Prior to Resource Plan Information

Planning Year	50/50 Forecasted Demand (MW)	Accredited Demand Response (MW)	Reserve Obligation Net of Accredited Demand Response (MW)	Aggregate Capacity (PRCs)	Local Capacity (PRCs)	Net Transaction Capacity (PRCs)	Total Accredited Capacity (PRCs)	Projected Summer Deficiency (-MW)
2010	696.8	25.0	702.1	582.1	41.0	85.0	708.1	6.1
2011	708.4	25.0	714.1	596.1	30.0	100.0	726.0	11.9
2012	720.1	25.0	726.4	596.1	30.0	100.0	726.0	-0.3
2013	732.0	25.0	738.8	596.1	14.7	50.0	660.7	-78.0
2014	750.4	25.0	758.0	596.1	14.7	50.0	660.7	-97.3
2015	772.7	25.0	781.3	596.1	14.7	0.0	610.7	-170.6
2016	793.2	25.0	802.7	366.1	14.7	0.0	380.7	-422.0
2017	818.4	25.0	829.1	366.1	14.7	0.0	380.7	-448.4
2018	849.3	25.0	861.4	366.1	14.7	0.0	380.7	-480.6
2019	861.8	25.0	874.4	366.1	14.7	0.0	380.7	-493.7
2020	874.4	25.0	887.6	172.7	14.7	0.0	187.4	-700.2
2021	887.2	25.0	901.0	172.7	14.7	0.0	187.4	-713.6
2022	900.1	25.0	914.5	172.7	14.7	0.0	187.4	-727.1
2023	913.1	25.0	928.1	172.7	14.7	0.0	187.4	-740.7
2024	926.3	25.0	941.9	172.7	14.7	0.0	187.4	-754.5
2025	939.7	25.0	955.8	172.7	14.7	0.0	187.4	-768.4

[1] The Module E resource adequacy obligation calculation is:
Reserve Obligation = (Peak Demand Forecast-Demand Response) x (1+Load Based Reserve Margin), where the reserve margin is currently 4.5%. Total Accredited Capacity is the sum of Aggregate PRCs, Local PRCs, and Net Transaction PRCs, where PRCs are MWs that have been converted to "Planning Resource Credits." Under Module E, only PRCs are eligible for designation toward the Reserve Obligation.

Table 2-2: Winter 2010-2025 Base Case Projected Load and Capability Prior to Resource Plan Information

Planning Year	50/50 Forecasted Demand (MW)	Accredited Demand Response (MW)	Reserve Obligation Net of Accredited Demand Response (MW)	Aggregate Capacity (PRCs)	Local Capacity (PRCs)	Net Transaction Capacity (PRCs)	Total Accredited Capacity (PRCs)	Projected Winter Deficiency (-MW)
2010	775.5	105.0	700.7	582.1	40.3	135.0	757.4	56.7
2011	787.1	105.0	712.8	596.1	29.3	100.0	725.3	12.5
2012	798.9	105.0	725.1	596.1	29.3	100.0	725.3	0.2
2013	817.1	105.0	744.2	596.1	14.7	50.0	660.7	-83.4
2014	839.2	105.0	767.3	596.1	14.7	0.0	610.7	-156.5
2015	859.6	105.0	788.5	366.1	14.7	0.0	380.7	-407.8
2016	884.6	105.0	814.7	366.1	14.7	0.0	380.7	-434.0
2017	915.3	105.0	846.8	366.1	14.7	0.0	380.7	-466.1
2018	927.7	105.0	859.7	366.1	14.7	0.0	380.7	-479.0
2019	940.2	105.0	872.8	366.1	14.7	0.0	380.7	-492.0
2020	952.8	105.0	886.0	172.7	14.7	0.0	187.4	-698.6
2021	965.6	105.0	899.3	172.7	14.7	0.0	187.4	-711.9
2022	978.4	105.0	912.8	172.7	14.7	0.0	187.4	-725.4
2023	991.5	105.0	926.4	172.7	14.7	0.0	187.4	-739.0
2024	1004.6	105.0	940.1	172.7	14.7	0.0	187.4	-752.7
2025	1017.9	105.0	954.0	172.7	14.7	0.0	187.4	-766.6

The data in the tables illustrates the capacity deficits that exist prior to plan development, based on the Company's existing resources as of June 1, 2010. The tables show that Otter Tail is slightly capacity deficient beginning in the summer of 2012 and that the deficiency grows throughout the study period as plants reach the end of their book lives, power purchase agreements (PPAs) expire, and demand continues to grow. Some resource accreditations are adjusted from 2010 accreditations in the table. Wind accreditation is assumed to drop to 3% from 8%, losing roughly 9 MW of accredited capacity in 2011. The 3% is a floor assumption for accreditation, recognizing that as wind penetration increases in the region, wind accreditation will decrease. Additionally, new emissions regulations may reduce accreditation of Otter Tail's small diesel resources by as much as 14 MW by April 2013. This assumption is also reflected in the table.

Resource Plan Development

The software model used for developing the integrated resource plan at Otter Tail is Strategist. The long-range load forecasts are incorporated into the Strategist database, along with the supply-side and demand-side resource alternatives available to the Company over the course of the study period. Strategist was then executed to develop a series of least-cost resource plans. Otter Tail defined the objective function as minimizing total revenue requirements, or total societal costs.

The Proview module within Strategist was executed to develop optimized resource plans for each scenario for the time period 2010 through 2025. Resource plans were developed in accordance with the resource planning rules, including evaluation of scenarios that varied load growth, applied externalities, and achieved specified renewable and conservation objectives.

Potential Resources

Otter Tail considers both demand-side and supply-side resources in long-term planning analysis. Appendix D provides a more detailed discussion of the resources that the Company evaluated. The relatively small size of Otter Tail dictates some of the resource alternatives available to the Company in meeting the needs of customers. Otter Tail is not large enough to develop some of the technologies that may provide economy of scale benefits. The emphasis on the development of the resource plan was on those technologies and technology sizes that are commercially viable to the Company. Table 2-3 provides a list of the supply-side alternatives evaluated.

Some of the alternatives in Table 2-3 were eliminated through a pre-screening process prior to Strategist modeling, as detailed in Appendix D. Criteria used in the pre-screening process included size adequacy, financing capability, risk acceptability, and price competitiveness with similar alternatives.

Table 2-3: List of Resource Alternative Technologies Evaluated and Included in Strategist Model

Potential New Resources Evaluated	Included in Strategist Model
Pulverized Coal – Sub-critical and Super-critical	Yes, without carbon capture and sequestration
Atmospheric Circulating Fluidized Bed Coal	No
Integrated Gasification Combined Cycle	No
Simple Cycle Combustion Turbines – Aeroderivative and Heavy-Duty	Yes
Natural Gas Combined Cycle	Yes
Reciprocating Engines	No
Battery Storage and Thermal Storage	No
Microturbines	No
Long Term Capacity and Energy Purchases	Yes
Solar Photovoltaic	No
Biomass	No
Nuclear	No
Wind	Yes
Conservation	Yes
Load Control (DSM)	Yes
Hydroelectric	No
Pumped Storage - Hydroelectric	No
Phosphoric Acid Fuel Cell	No
Projects for Existing Facilities	
Big Stone Plant Environmental Project using Best Available Retrofit Technology (BART)	Yes
Hoot Lake Environmental and Upgrade Project	Yes
Frame 5s Upgrade Project	Yes

Additionally, the model included alternatives for potential capital projects for existing plants. An Air Quality Control System (AQCS) project for Big Stone Plant using Best Available Retrofit Technology (BART) was made available in 2016. This upgrade will be necessary for continued operation of this facility and is included to determine if this upgrade is economic when compared to other available alternatives. The existing plant projects also included environmental and plant upgrades at the

Company's baseload coal-fired units, Hoot Lake #2 and #3, and were made available in 2019, as well as projects for the three Frame 5 oil-fired peaking units located in Lake Preston, SD and Jamestown, ND. These upgrades are expected to be necessary for continued operation of these facilities and are included to determine if these upgrades are economic when compared to other available alternatives. Altogether, the Frame 5 peaking unit projects would continue to contribute roughly 60 MW of accredited capacity, whereas the Hoot Lake projects would continue to contribute about 127 MW of accredited capacity. In addition, a certain amount of market reliance was allowed in the model due to the favorable forecast market conditions for both capacity and energy prices.

Preferred Resource Plan

The preferred resource plan as developed by the Strategist Proview optimization analysis is shown in Table 2-4. The table identifies the accredited annual capacity and annual selection of each resource. The preferred resource plan is the least cost plan developed by the Strategist model without the consideration of environmental externalities, CO_2 values, or other proposed environmental regulation and using base case assumptions. As shown, the preferred plan is expected to cost $4.025B, a net present value in 2010$ of revenue requirements (NPVRR). Figure 2-1 shows a pie chart of the resource additions by 2025 for the base case, or preferred plan. Essentially, about 60% of the plan is comprised of improvements at existing resources and market purchases that are similar to existing levels. The remaining 40% of the plan is comprised of the following components: 64% natural gas simple cycle combustion turbines, 21% conservation and demand response, and 15% wind generation.

Figure 2-1: Preferred Plan by Resource Selection, Summer Capacity (MW), and Percent of Total in 2025
(Wind is shown as installed capacity. Accredited capacity for wind was assumed to be 3%.)

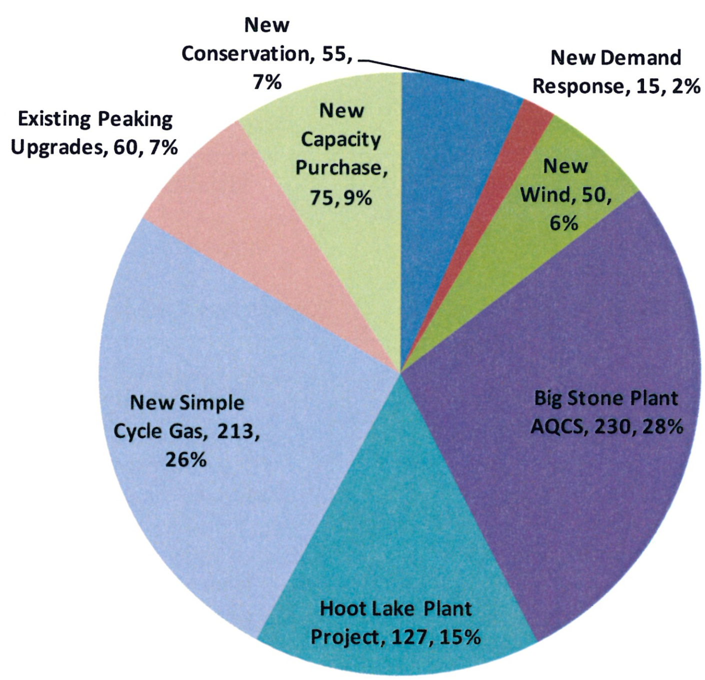


Table 2-4: Preferred Resource Plan Summary

Description	Preferred Plan	Comments
NPVRR ($000)	$4,025,983.50	This is the Net Present Value of Revenue Requirements in 2010$.
Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate		
2010	1.2% MN CIP	Implementation of an annual 1.2% Conservation Improvement Program in Minnesota
2011	New Demand Response	Implementation of a plan to grow summer demand response by 15 MW and winter by 30 MW by 2025.
2012	50 MW Wind	Installation of 50 MW of wind under the federal PTC
2013	<75 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2014	39.6 MW Aero NG CT	Commercial Operation of aeroderivative, natural gas-fired, simple cycle combustion turbine.
	<100 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2015	<150 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2016	229.7 MW BSP AQCS Project	Install Air Quality Control System (AQCS) using Best Available Retrofit Technology (BART) at Big Stone Plant.
	<150 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2017	86.5 MW Aero NG CT	Commercial Operation of aeroderivative, natural gas-fired, simple cycle combustion turbine.
	<75 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2018	86.5 MW Aero NG CT	Commercial Operation of aeroderivative, natural gas-fired, simple cycle combustion turbine.
	<75 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2019	127.1 MW Hoot Lake Project	Installation of Hoot Lake Plant Project
	60.0 MW Frame 5s Project	Installation of Frame 5 Oil Peaker Project
	<75 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2020	<75 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2021	<75 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2022	<75 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2023	<75 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2024	<75 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.
2025	<75 MW 1-Yr Capacity	Purchase balance of capacity in short-term contracts.

As shown in Table 2-4, the plan includes a 1.2% CIP energy goal in MN, 15 MW of new incremental summer demand response capability by 2025, and 50 MW of nameplate wind generation in 2012. The preferred plan added simple cycle, aeroderivative combustion turbines in 2014, 2017, and 2018 at accredited levels of about 40 MW, 87 MW, and 87 MW, respectively. The preferred plan included investment in existing resources: an environmental upgrade at Big Stone Plant (230 MW) using Best Available Retrofit Technology (BART) for installation of an Air Quality Control System (AQCS), environmental upgrades and capital projects at Hoot Lake #2 and #3 (127 MW), and capital projects for three Frame 5 oil-fired peaking units (60 MW). Throughout the study period the plan relies on bilateral capacity contracts for the balance of resource adequacy obligations, capped at 75 MW after 2016. In addition to capacity purchases, the preferred plan relies on the market for energy to cover maintenance outages or for economic conditions. The import capability from the energy market was capped at 100 MW and energy imports reached 12% of the Company's total energy requirements in 2025.

Figure 2-2 shows the capacity resource additions along with existing resources over the study period and Figure 2-3 shows the energy contribution by fuel category for 2010-2025 under the preferred plan.

Figure 2-2: Preferred Plan Capacity Resources and Reserve Obligation 2010-2025 (MW)

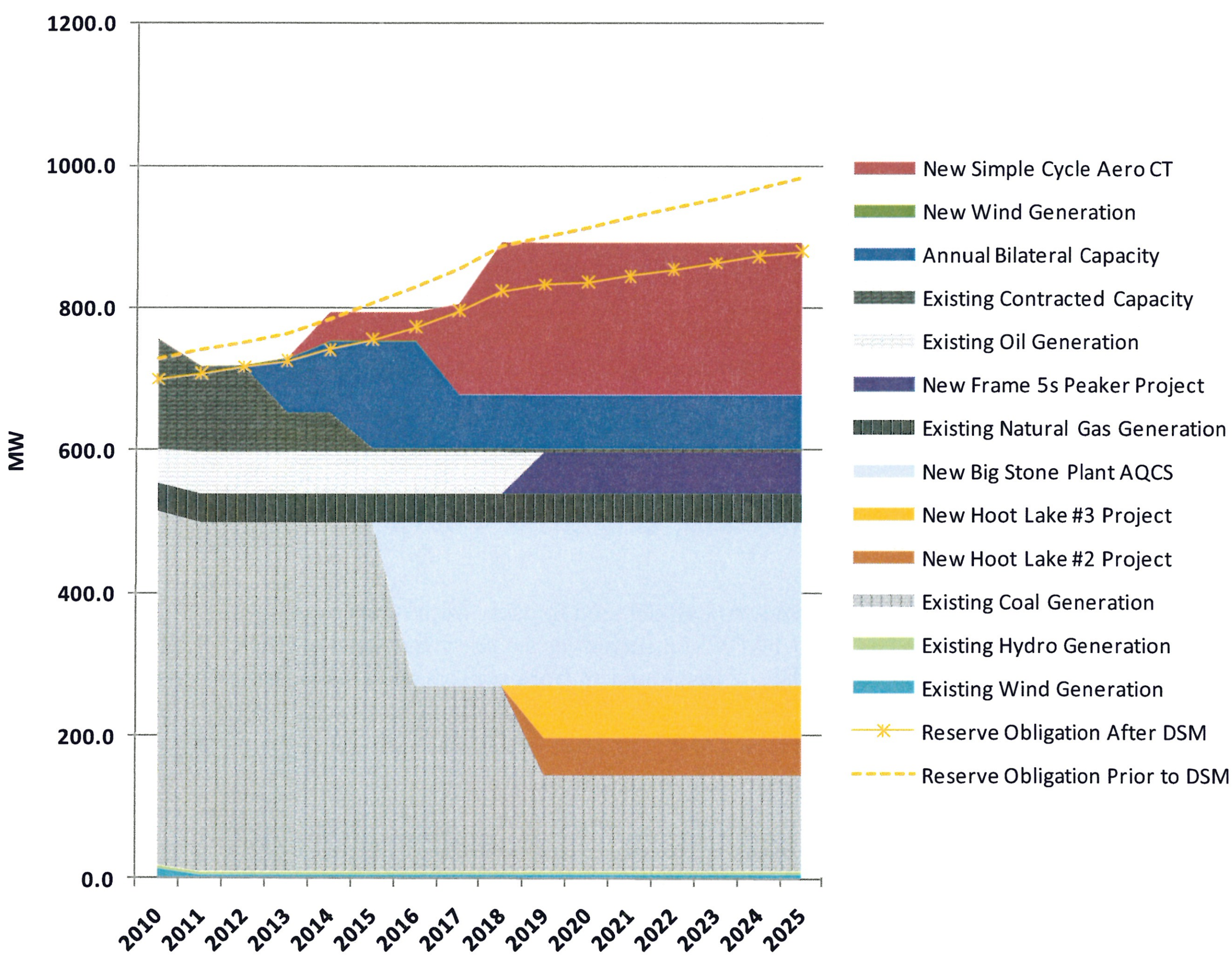
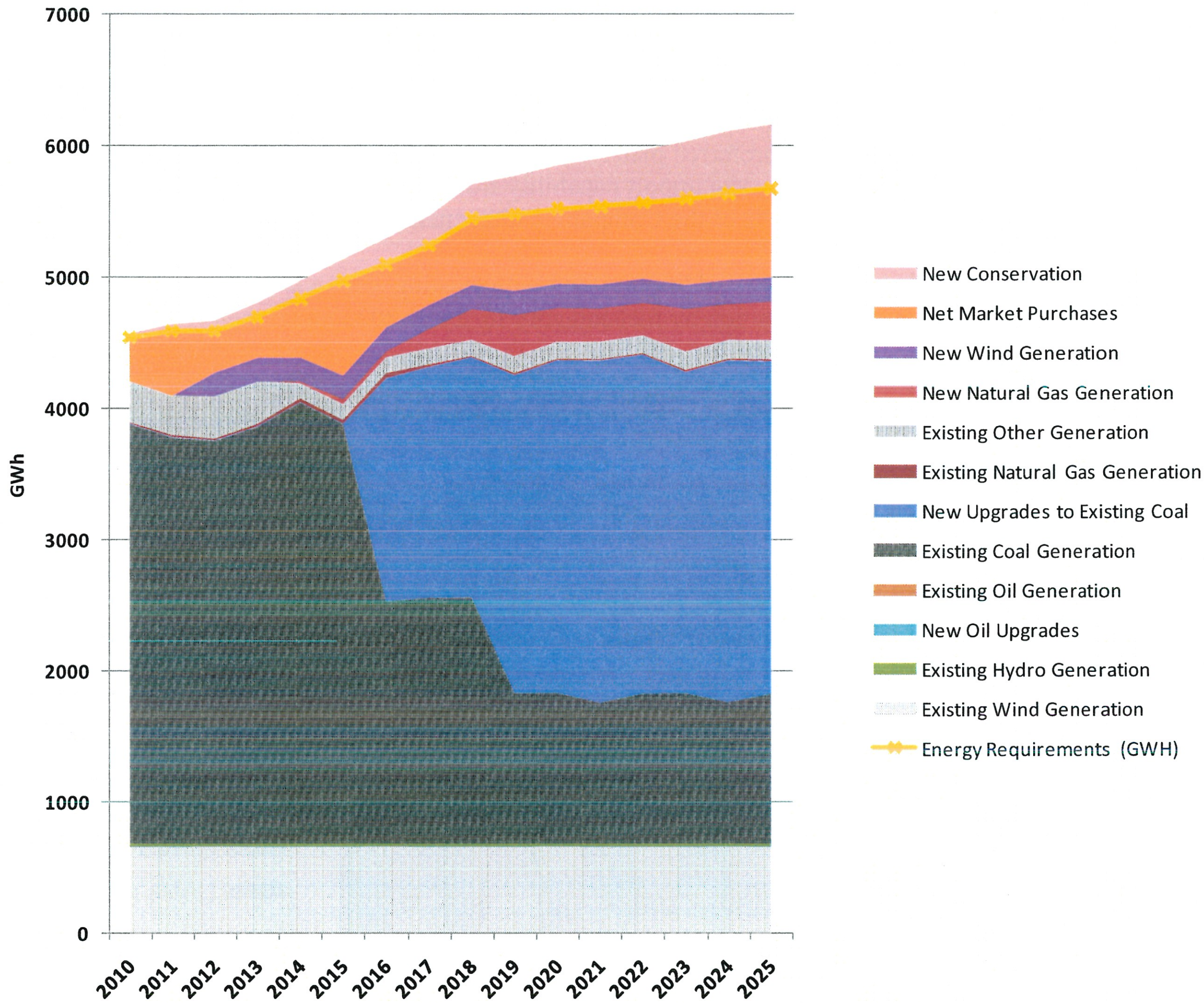


Figure 2-3: Preferred Plan Energy Resources and Requirements 2010-2025 (GWh)

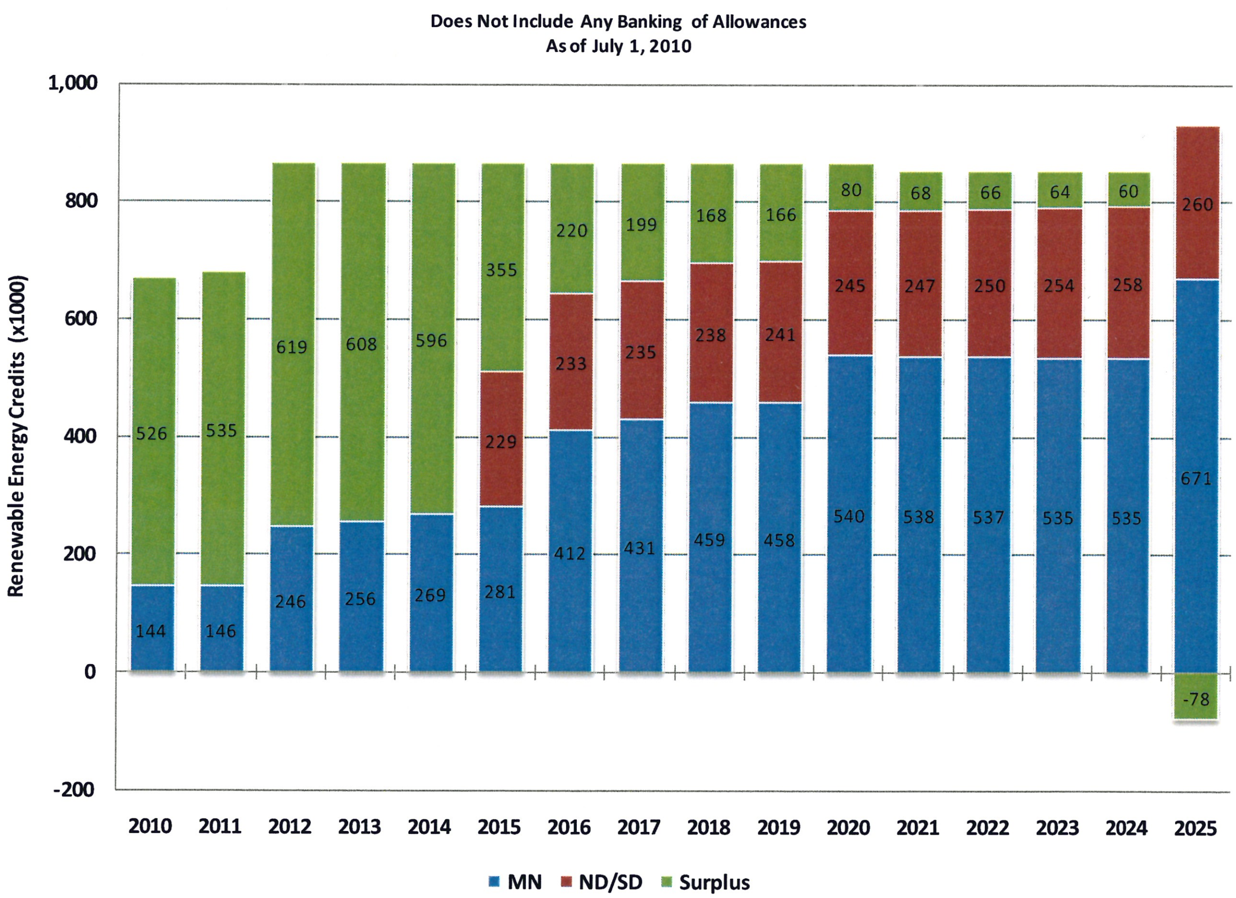


By the end of the study period, summer peak demand impacts from new conservation programs for all jurisdictions are expected to be 55.1 MW, not including the reserve margin savings. Winter peak demand impacts are expected to be 62.4 MW. These impacts from conservation measures reduce the average peak demand growth rate by 0.40% by 2025. Likewise, the cumulative savings due to energy efficiency for all jurisdictions reaches just over 482 GWh by 2025 and reduces the average energy growth rate by 0.52%.

Because Otter Tail is a multi-jurisdictional utility with varying requirements regarding the treatment of carbon dioxide (CO_2), the Company's current goal is to maintain CO_2 emissions at or below the average level emitted from 2002-2004. Throughout the study period, CO_2 emissions in the preferred plan do not exceed that average level. Renewable resources and conservation programs contribute toward the Company's achievement of this objective

Otter Tail has aggressively added renewable resources in recent years and is therefore well ahead of schedule in complying with REO/RES requirements. The model did select an additional 50 MW of wind resources as being economic. This addition will further support compliance with REO/RES requirements. Figure 2-4 demonstrates the planned compliance with the REO/RES requirements of Minnesota, North Dakota, and South Dakota, assuming no banking of renewable energy credits (RECs) and no specific allocation between state jurisdictions. Otter Tail has sufficient renewable generation to meet the RES in Minnesota and the REO in both North Dakota and South Dakota through 2024 assuming no banking of RECs. The federal Production Tax Credit (PTC) and other North Dakota state financial incentives available to wind generation development have helped to make wind generation an economic alternative. The renewable generation shown in the table assumes certain levels of wind generation performance annually, which is subject to fluctuations. Additional smaller wind installations are likely to take place so that wind generation for the Company may increase above what the Company is projecting.

Figure 2-4: Planned Compliance with REO/RES Regulation in All Jurisdictions

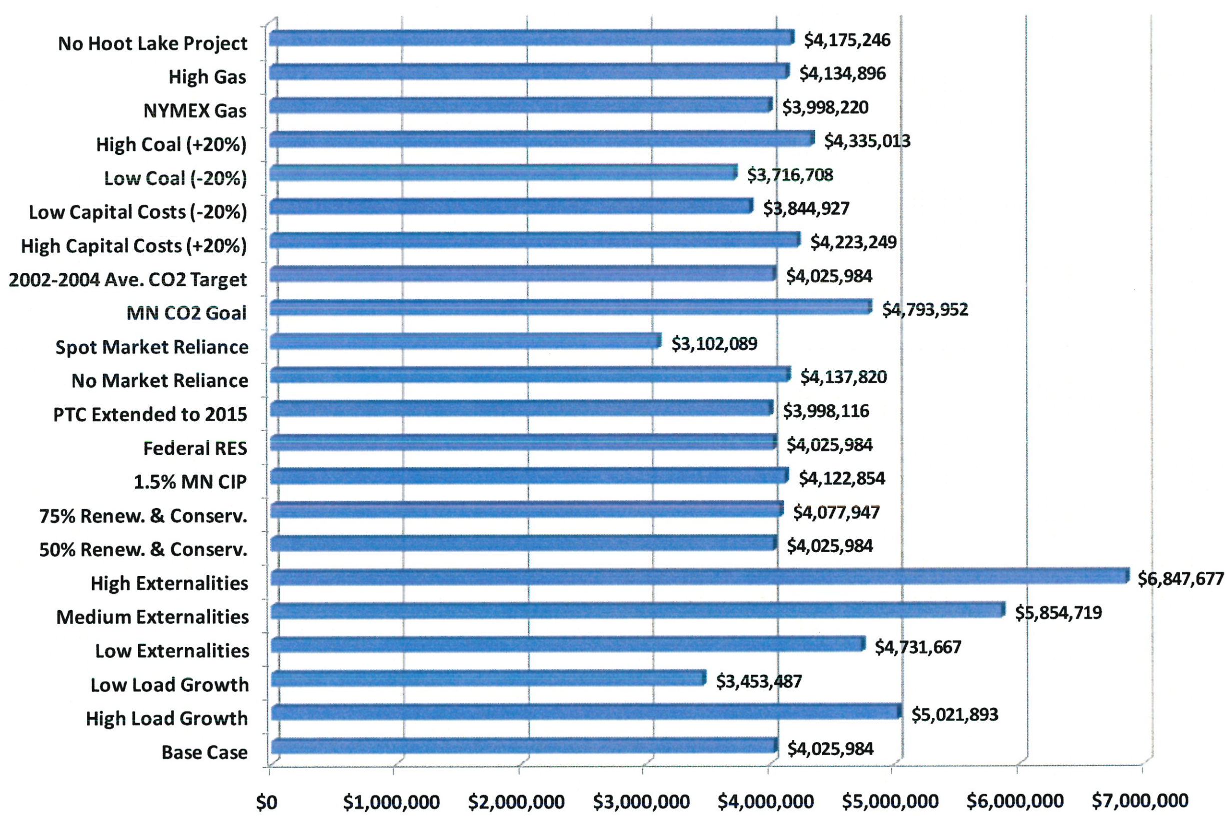


Preferred Plan is in the Public Interest

The Company is committed to operating its generation facilities as efficiently as practicable while minimizing adverse effects on the environment. This plan provides significant environmental benefits as evidenced by the Air Quality Control System at Big Stone Plant being part of the least cost plan and also maintaining the projected emissions of CO_2 near historical 2005 levels. New resources have been selected that will meet the Company's needs while maintaining flexibility and limiting the risk of exposure to changes in financial, social and technological factors beyond its control. With minimal resource additions during the initial five-year period, the plan maintains flexibility during a period of much uncertainty including recession impacts and rebound, climate change proposals, off-shore drilling, and other factors that can have a material impact on the industry. In addition, customers will be provided with increased opportunities to improve their energy efficiency. With the usage of excess RECs generated in prior years, the preferred plan is compliant with the renewable energy objectives and standards across the entire Otter Tail tri-state system throughout the planning period as described previously. This resource plan satisfies the legal and regulatory requirements in the multi-state service territory, and allows Otter Tail and its customers to realize the benefits of operating as a single system while recognizing the differing state requirements.

Figure 2-5 shows a summary of the Net Present Value of Revenue Requirements for all scenarios evaluated for this resource plan.

Figure 2-5: Net Present Value of Revenue Requirements ($000) by Scenario



Much of the cost differences between the sensitivity scenarios and the base case are driven primarily by cost assumptions and not by changes in resource additions. Each sensitivity scenario may also have variations in the load growth assumed or conservation level achieved which may drive costs to be higher or lower. With the exception of mid- to high- externalities, high load growth, and market reliance scenarios, the sensitivities do not indicate much change in terms of resource additions from the preferred plan. Further discussion on the sensitivity studies presented in the figure is provided in Section 5.

The base case resource plan, or preferred plan, satisfies all rules and requirements of the Minnesota statutes and rules, provides a clear concise report to interested parties of what Otter Tail intends to do to satisfy customer needs in the near term, and identifies the resources the Company is considering for viable options for the long term.

The preferred resource plan as presented by the base case balances a variety of technologies and fuel types to meet customer needs. It represents the most economic plan developed with a model that successfully integrates demand-side and supply-side resource analysis. Otter Tail serves customers in three states. To provide operating efficiencies, the Company strives to operate and plan its system as a single entity to the benefit of all customers. At times that creates challenges as compliance must be maintained with the many statutes, rules, and regulations in three separate states and three separate regulatory commissions. Otter Tail believes that this resource plan meets that challenge and successfully provides a plan that is reasonable and satisfies the needs of all three states. North Dakota Century Code Section 49-02-23 prohibits the use of environmental externality cost values in the selection of a utility resource. Conversely, MN Stat. 216B.2422 expressly requires the consideration of environmental externalities in the development of the resource plan.

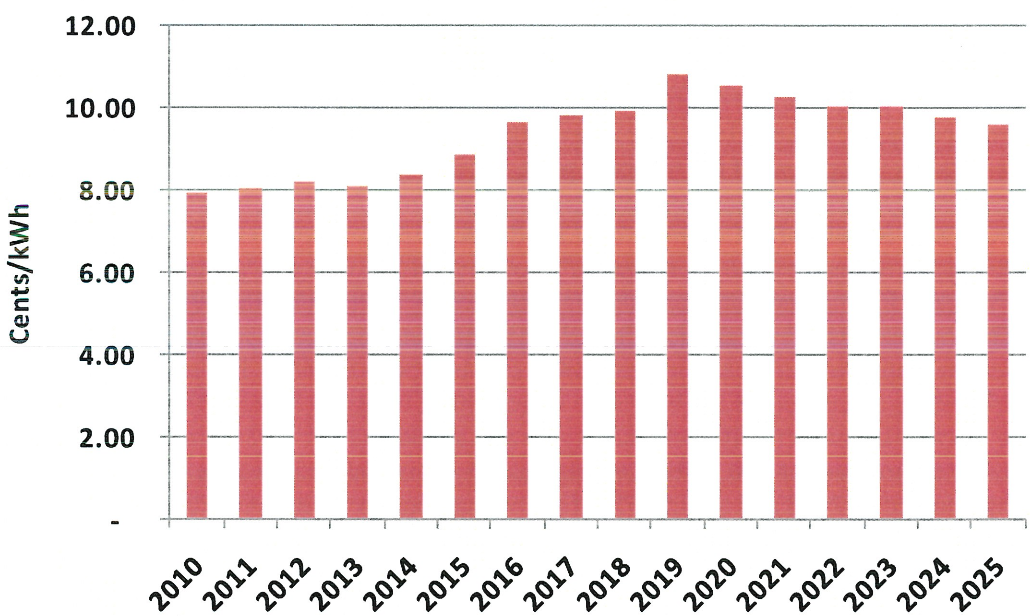
Compliant with MN Statutes, the Company evaluated low, mid, and high externality scenarios for this resource plan and as defined by the Commission's June 1, 2010 Notice of Updated Environmental Externality Values. Each externality case also assumed a CO_2 tax starting in 2012 and escalating annually. The low externalities scenario selected the same resources as those selected in the preferred plan (or zero externality scenario) and increased the cost by about $706M. The mid and high externality scenarios also increased costs over the base case by roughly $1.8B and $2.8B. These two scenarios replaced the Hoot Lake project with combined cycle and added another 50 MW of wind. Otter Tail already owns or contracts over 180 MW of wind, making up roughly 25% of the Company's forecasted summer peak demand in 2010 and about 15% of 2009 retail energy sales. An additional 50 MW in 2012 as selected in the base case will increase that share to roughly 230 MW or nearly 33% of forecasted summer peak demand and about 20% of 2009 retail energy sales. Taken in context with the expiration of the federal production tax credit (PTC) in 2012, the uncertainty of CO_2 regulation, and the depressed energy market forecasts, the Company is committed to the base case as the preferred plan in the near term, recognizing significant overlap among scenarios in that time frame and maintaining flexibility to adapt to potential changes in regulation.

MN Stat. 216B.2422 also requires evaluation of the resource plan for low and high load growth scenarios and for scenarios that evaluate meeting 50% and 75% of future resource needs using demand side management and renewable resources. Like the externality scenarios, the load growth scenarios also varied from the preferred plan in total cost and resource selection. The Company has determined to plan for the most likely forecast, recognizing that this plan can adapt as time progresses to accommodate variations in actual load growth from the present long-range forecast. The preferred plan meets 52% of new energy requirements for Minnesota customers using renewable resources and energy efficiency and conservation. To achieve a 75% level, the Company would require greater wind generation additions at additional and potentially higher costs depending on available incentives. The low and high load growth scenarios were $572M lower and $995M higher, respectively, than the preferred plan.

Preferred Plan Rate Impacts

Figure 2-6 shows the potential rate impact of the preferred resource plan. The data shown is the average annual rate as developed by the Strategist model for the total system and represents rate class total revenue divided by rate class total sales. There are a number of parameters in the operation of the model that will impact rates. The Strategist model assumes automatic rate increases each year to meet the targeted rate of return and this generally is not mirrored in utility experience. In reality, rate cases take place periodically as needed and have an inherent amount of regulatory and administrative lag. The Strategist model rate impact calculation has taken into account all generation and related transmission additions in the preferred plan. However, it does not include all projected capital expenditures, asset based sales, or projected CO_2 costs. The graph shows that the Company has a significant period of investment in generation to address capacity deficiencies primarily between 2012 and 2019. Consistent with the preferred plan, rate increases plateau after 2019.

Figure 2-6: Preferred Resource Plan Estimated Rate Impacts (2010¢/kWh)



Five-Year Action Plan

The implementation of the preferred resource plan will have a number of significant events and tasks. Some of these tasks have already been started due to the critical timing involved. Table 2-5 identifies specific major items that require action in the first five years of the planning period. The five year action plan is for the years 2011-2015, however, the action items in 2010 are also provided. As shown the major activities will involve efforts related to the major components of the preferred plan. These efforts will focus on conservation and demand response development, pursuit of a wind resource for commercial operation by 2012, progress on the existing resource upgrades and projects, and development of natural gas-fired simple cycle combustion turbines in 2014, 2017, and 2018.

Table 2-5: Five-Year Action Plan Activities

Year	Activity
2010	July 1 Triennial CIP filing for 2011, 2012, 2013.
	Implement marketing plan to meet DSM objectives
	Initiate Request for Proposal process for 2012 Wind Farm
	Initiate detailed evaluation of Hoot Lake Plant
	File environmental and regulatory permitting for Big Stone Plant AQCS BART project
	Execute Large Generator Interconnection Agreement for < 50 MW aeroderivative combustion turbine.
	File environmental and regulatory permitting for < 50 MW aeroderivative combustion turbine
	Initiate detailed design on Big Stone Plant AQCS Project
2011	No new action items initiated
2012	Initiate construction on Big Stone AQCS Project
	Commercial operation of 2012 Wind Farm
	Initiate detailed design and procurement for < 50 MW aeroderivative combustion turbine
	File Interconnection Request for 2017 combustion turbine
2013	On-going construction of Big Stone Plant AQCS project
	June 1 Triennial CIP filing for 2014, 2015, 2016
	Begin construction of < 50 MW aeroderivative combustion turbine
	File Certificate of Need, environmental permitting for 2017 combustion turbine
2014	On-going construction of Big Stone Plant AQCS project
	Commercial operation of < 50 MW aeroderivative combustion turbine
2015	Commercial operation of Big Stone Plant AQCS

Conclusion

The Company has continued to optimize existing resources and obtain supplemental capacity and energy through the wholesale market and from independent power producers to meet both customer needs and resource adequacy requirements. This strategy will continue while balancing risk and economics. Cost-effective energy efficiency and demand response is selected throughout the study period. The Plan includes the addition of another 50 MW of wind generation to serve customers' energy needs. This resource will also assist the Company in complying with current REO/RES requirements in all three states where Otter Tail does business. Capacity purchases and peaking unit projects to meet capacity needs and backup Otter Tail's wind generation will be a focus in the 2014-2018 timeframe. In 2016, the Big Stone Plant Air Quality Control System (AQCS) project using Best Available Retrofit Technology (BART) will be vital to keeping the Company's electric service reliable, economic, and environmentally responsible. Capital projects to maintain operations of Hoot Lake Units #2 and #3 and the oil-fired peaking units (Jamestown #1 and #2 and Lake Preston) are critical components to the preferred plan. The preferred resource plan presented here accomplishes the goal of meeting customer needs while incorporating many competing considerations. This plan will help to shield customers from the volatility of the marketplace and serve them reliably throughout the planning period.

Revised 9-17-2010

Section 5

Preferred Resource Plan

This section replaces the original section 5

Revised 9-17-2010

5 Preferred Resource Plan

The Preferred Resource Plan details the expected specific activities of Otter Tail with respect to the resources associated with the preferred plan in the 2011 – 2016 time period. It also identifies possible resources that could be used to serve customer loads over the entire 2011 – 2025 resource planning period. This section first discusses details associated with the preferred resource plan. Following that discussion, this section presents the results for the scenarios required by the Minnesota Rules for resource plan filings, including: high and low load growth scenarios, externality scenarios, and renewable and conservation scenarios. The Company's specific resource plan, presented in Table 5-1, shows the estimated MW impact of each resource group by calendar year. Figure 5-1 shows the resource stack of new additions and existing resources compared to the resource adequacy obligation. The peak demand is shown net of new and existing DSM.

Table 5-1: Annual Summer Accredited Capacity Values of Potential Future Resources for the Preferred Plan or Base Case (MW)

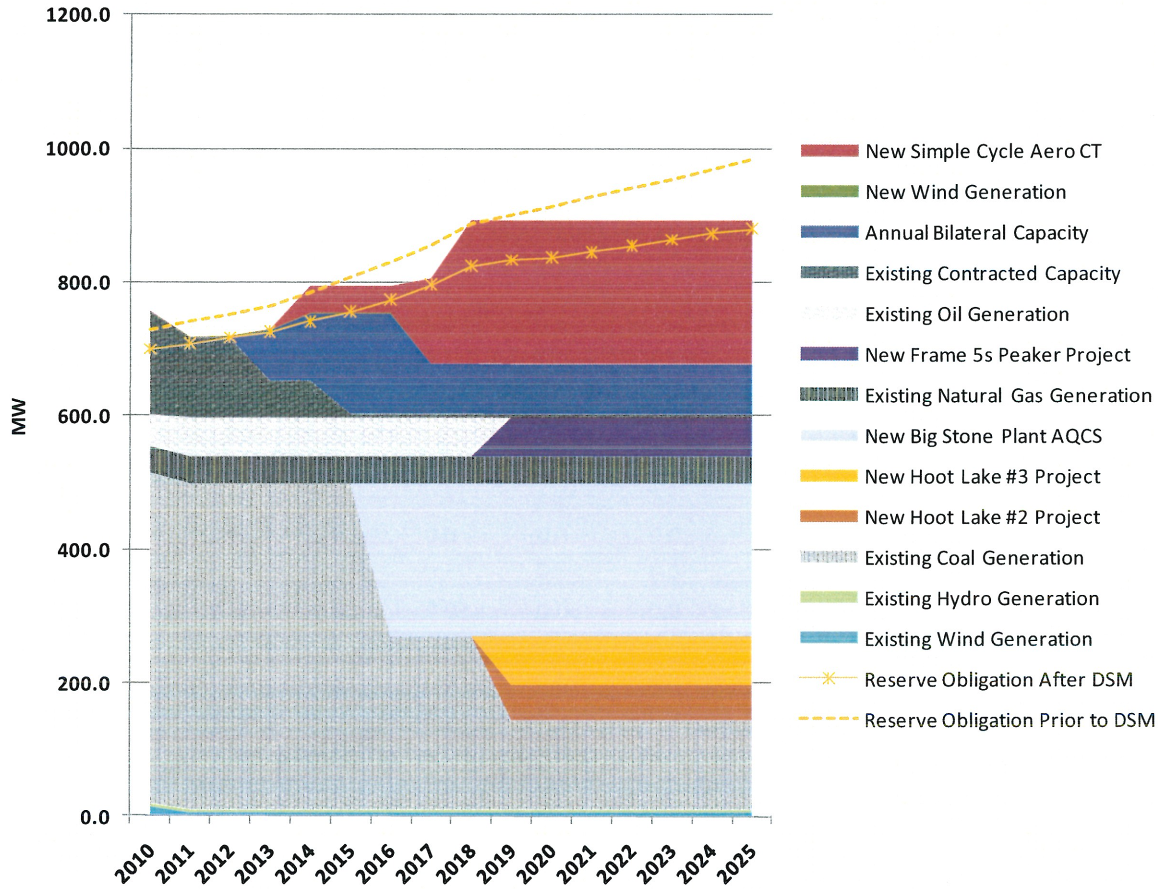
Resource	2010	2011	2012	2013	2014	2015	2016	2017
1.2% MN CIP[1]	-2.6	-5.3	-8.3	-11.6	-14.8	-18.2	-21.5	-25.2
New Demand Response[1]	0.0	0.0	0.0	0.0	0.0	-5.0	-5.0	-5.0
Annual Bilateral Capacity	0.0	0.0	0.0	75.0	100.0	150.0	150.0	75.0
Wind Generation[2]	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0
Frame 5s Peaker Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hoot Lake #3 Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hoot Lake #2 Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Aeroderivative NG CT	0.0	0.0	0.0	0.0	39.6	39.6	39.6	126.1
Big Stone Plant AQCS	0.0	0.0	0.0	0.0	0.0	0.0	229.7	229.7

Resource	2018	2019	2020	2021	2022	2023	2024	2025
1.2% MN CIP[1]	-29.0	-32.9	-36.9	-41.2	-45.3	-49.5	-53.5	-55.1
New Demand Response[1]	-5.0	-5.0	-10.0	-10.0	-10.0	-10.0	-10.0	-15.0
Annual Bilateral Capacity	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Wind Generation[2]	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Frame 5s Peaker Project	0.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Hoot Lake #3 Project	0.0	73.6	73.6	73.6	73.6	73.6	73.6	73.6
Hoot Lake #2 Project	0.0	53.5	53.5	53.5	53.5	53.5	53.5	53.5
Aeroderivative NG CT	212.6	212.6	212.6	212.6	212.6	212.6	212.6	212.6
Big Stone Plant AQCS	229.7	229.7	229.7	229.7	229.7	229.7	229.7	229.7

[1]Conservation and demand response are netted from the peak demand forecast prior to calculation of the resource adequacy requirement.

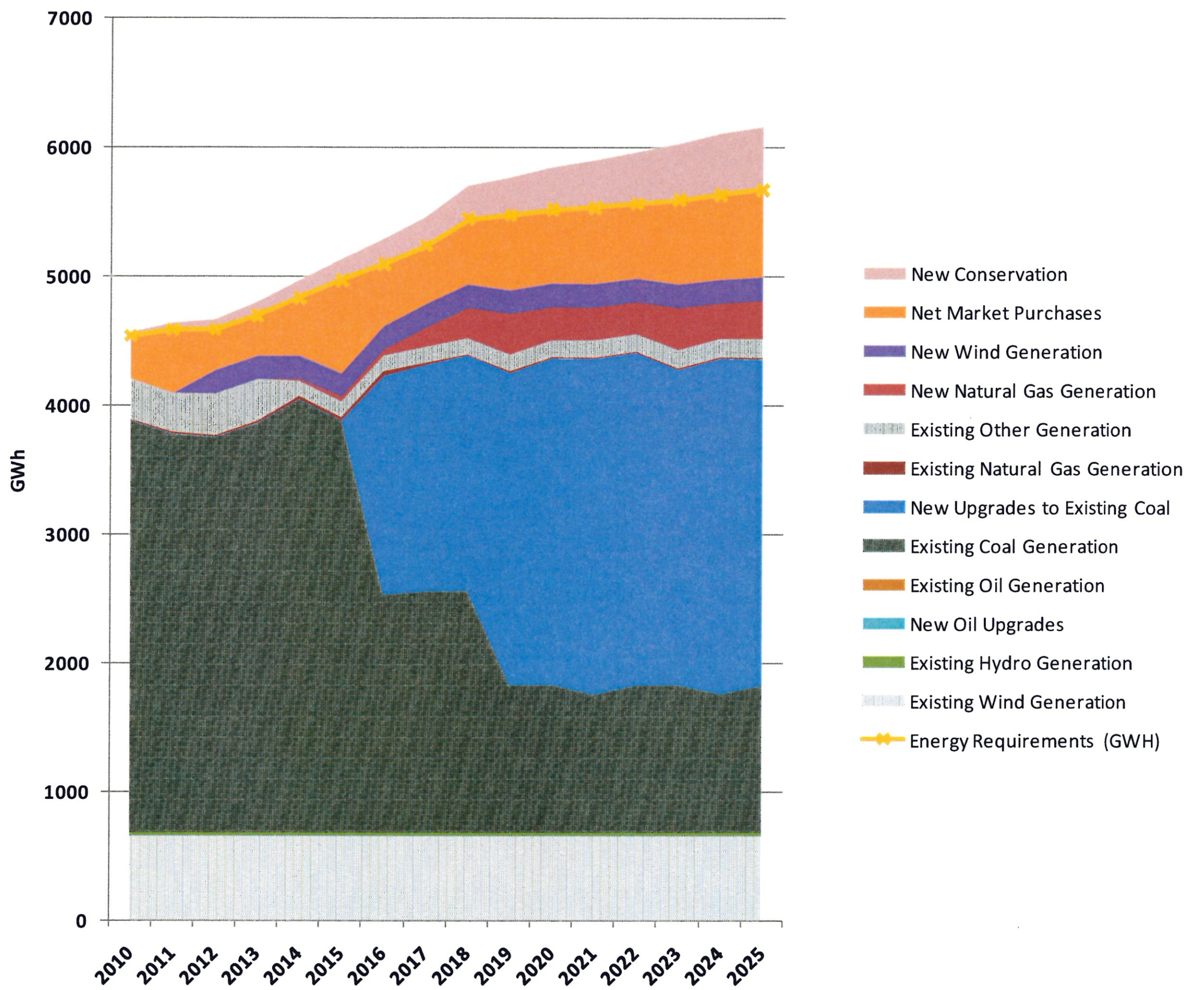
[2]Wind generation is shown at nameplate capacity. Accredited capacity expected to be around 3% of nameplate.

Figure 5-1: 2010-2025 Capacity Resources and Reserve Obligation for Preferred Plan (MW)



As Figure 5-1 shows, the new resource additions are added primarily above the 700 MW level. Below that level are upgrades to existing facilities and environmental projects, or existing levels of market purchases. New wind generation is barely visible due to its low capacity accreditation value. However, its impacts are better represented in Figure 5-2 which shows the energy sources in the preferred plan by fuel type. As in the capacity representation, new resource additions are primarily represented above the 4,000 GWh level. Below that level are upgrades to existing facilities. As shown in Figure 5-2, conservation contributes a significant portion to the Company's future energy needs, as do new wind generation and continued market purchases.

Figure 5-2: 2010-2025 Energy Resources and Energy Requirements for Preferred Plan (MW)



5.1 Preferred Resource Plan Description

The Otter Tail preferred resource plan is the least cost plan selected by the Strategist model under the Company's base case assumptions, totaling $4.025B in NPVRR in 2010$. The base case, or preferred plan, is the zero externality and zero CO_2 value scenario. It is important to recognize that the Midwest ISO reserve capacity obligation is a *minimum* obligation. It is quite likely that the Company will seek to have a small margin above the obligation to reduce the risk of falling below the requirement and being forced to purchase capacity at the Midwest ISO "Cost of Next Entry" rate, estimated to be $90,000/MW-month. Following is a description and comment on each of the resources identified in Table 5-1.

- **1.2% CIP** – The model chose an annual energy efficiency and conservation alternative for Minnesota load that was 1.2% of average retail sales for the prior three years. By 2025, summer peak demand impacts from energy efficiency and conservation are expected to be 55.1 MW, not including the reserve margin savings. Winter peak demand impacts are expected to be 62.4 MW. Table 5-2 presents the expected annual savings due to energy efficiency for all jurisdictions Otter Tail serves by 2025. South Dakota has an approved energy efficiency goal of approximately 0.4% of retail sales, which is not reflected in Table 5-1, but included in the data presented in Table 5-2. The cumulative savings due to energy efficiency for all jurisdictions reaches just over 482 GWh by 2025and reduces the average energy growth rate by 0.52% over the study period and the peak demand growth rate by 0.40%.

Table 5-2: Estimated MWh Savings Due to Conservation in all Jurisdictions
(2009 CIP data is included since the impacts of those programs are not included in the load forecast)

Year	Incremental Annual Savings (GWh)	Cumulative Annual Savings (GWh)
2009	18.8	18.8
2010	23.3	42.1
2011	24.3	66.4
2012	26.7	93.1
2013	28.0	121.1
2014	28.4	149.5
2015	29.0	178.5
2016	30.3	208.8
2017	31.5	240.4
2018	32.8	273.2
2019	34.4	307.6
2020	35.6	343.1
2021	36.3	379.4
2022	36.3	415.7
2023	36.2	451.9
2024	36.2	469.2
2025	36.2	482.1

- **Demand Response** – Demand response includes both load management capability and customer contracts that allow load shedding to a firm service level. In the preferred plan, demand response capability was selected to increase annually and reach 15 MW of additional summer season capability and 30 MW of additional winter season capability by 2025. To allow the Company time to confirm measurement and verification capability of incrementally new demand response, the new demand response was stair-stepped in every 5 years in 5 MW increments. Otter Tail has invested in and developed the demand response capability over many years. This resource is critical in reducing the Company's peak demand and smoothing the peak demands between summer and winter. Because the Company has substantial winter demand response capability and is winter peaking, the winter peak demand obligations are reduced to a level more in line with summer peak demand. According to Midwest ISO Module E rules, the accredited capability is netted directly from the peak demand forecast prior to calculation of the resource adequacy obligation and thereby saves the Company not only the difference, but the reserve margin requirement as well.

- **Bilateral Capacity Purchases** – The model was able to select annual bilateral capacity contracts in 75 MW blocks. It is not necessarily the case that the Company will require exact multiples of that much capacity. Rather, these block purchases should be viewed as a purchase "up to the stated amount." The block size was selected to compete with the natural gas combustion turbine alternatives which were between 69.2 MW and 86.5 MW of accredited capacity. Due to the favorable capacity market prices, the model relied on annual bilateral capacity contracts as much as it was allowed throughout the study period. Capacity purchases will be used up to the amount shown to meet the balance of resource adequacy obligations in any month of each respective year.

- **Wind Generation -** The model selected 50 MW of wind generation in 2012, assuming an ownership cost that incorporates the federal PTC and North Dakota state incentives. Accredited capacity of wind generation was set at 8% for the 2010 planning year, but dropped to roughly 3% for the remaining years of the study period. This accreditation level is assumed for all wind generation resources in that time frame, recognizing that the accreditation levels for wind generation will likely drop as greater amounts of wind generation penetrate the region. Annual energy from the new wind generation resources is expected to be based on a capacity factor of approximately 41%.

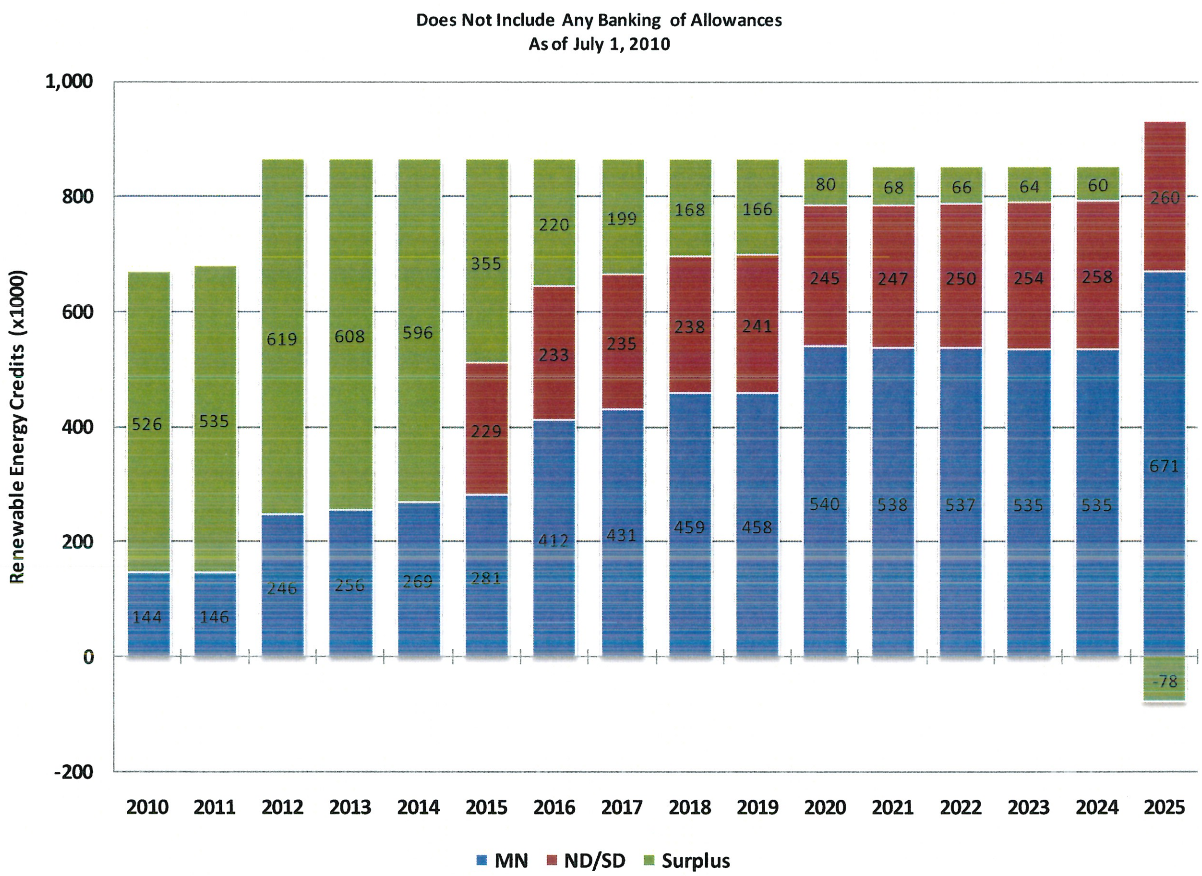
- **Combustion Turbines –** Three aeroderivative simple cycle, natural gas-fired combustion turbines were selected in the preferred plan. These turbines included 39.6 MW of accredited capacity in 2014, 86.5 MW of accredited capacity in 2017, and 86.5 MW of accredited capacity in 2018.

- **Existing Plant Projects –** Several projects on existing baseload and peaking resources were selected in the preferred plan. These upgrades are expected to be necessary for continued operation of these facilities and were included in the analysis to determine if these upgrades are economic when compared to other available alternatives. The projects totaled roughly 417 MW of accredited capacity and included:

    - <u>Environmental upgrades for an Air Quality Control System (AQCS) at Big Stone Plant</u> (229.7 MW accredited capacity) using Best Available Retrofit Technology (BART) was selected in 2016 and included installation of flue gas desulfurization equipment and a selective catalytic reduction system for control of NOx emissions. Plant efficiency was assumed to be reduced by 1.5% and costs for operations and maintenance were assumed to increase. These assumptions are provided in Appendix F.
    - <u>Environmental and plant upgrades at Hoot Lake Plant Units #2 and #3</u> (127 MW accredited capacity) are expected to continue operations as long as it remains cost effective to do so. The preferred plan selected environmental and plant upgrade capital projects to maintain this facility in 2019. Similar to the Big Stone Plant environmental project, it was assumed that plant efficiency would decrease by 1.5% and costs for operations and maintenance would increase. A more thorough evaluation of specific Hoot Lake Plant options will be conducted and factored into Otter Tail's next IRP filing.
    - <u>Jamestown and Lake Preston oil-fired peaking units</u> (about 60 MW accredited capacity) are also expected to continue operations as long as it remains cost effective. Capital projects to continue operations of these units were selected in the preferred plan in 2019.

Figure 5-3 represents the planned compliance with REO/RES regulation in all jurisdictions under the preferred plan.

Figure 5-3: Planned Compliance with REO/RES Regulation in All Jurisdictions



As shown, Otter Tail expects to be surplus renewable energy credits through 2024. The addition of 50 MW of wind generation in the preferred plan provides Otter Tail sufficient renewable generation to meet the RES in Minnesota through 2025 (assuming banking of RECs) and the REO in both North Dakota and South Dakota through 2025.

The federal PTC and other North Dakota state financial incentives available to wind generation development help to make wind generation an economic alternative. The renewable generation shown in the figure assumes certain levels of wind generation performance annually, which is subject to fluctuations. Smaller wind generation installations and additional renewable energy projects are likely to take place so that renewable energy generation for the Company may increase above what the Company is projecting.

5.2 Load Growth Scenarios

The base case was executed assuming a low load growth scenario and a high load growth scenario. Table 5-3 presents a comparison of these two runs with the base case. As shown, the low load growth scenario results in lower total revenue requirements and fewer resource additions and the high load growth scenario results in higher total revenue requirements and more resource additions.

Table 5-3: Comparison of Load Growth Scenarios to Base Case

Scenario	Base Case	High Load Growth	Low Load Growth
NPVRR ($000)	$4,025,984	$5,021,893	$3,453,487
Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate			
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	<50 MW 1-Yr Capacity	
2012	50 MW Wind	50 MW Wind <50 MW 1-Yr Capacity	
2013	<75 MW 1-Yr Capacity	<100 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	<100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<175 MW 1-Yr Capacity	<150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project 46.2 MW Combined Cycle <50 MW Capacity 86.5 MW Aero NG CT	229.7 MW BSP AQCS Project <150 MW Capacity
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	46.2 MW Combined Cycle 60.0 MW Frame 5s Project	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	55 MW Supercritical Coal <75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	55 MW Supercritical Coal <75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
New Resources by Category (MW)			
Conservation	-55	-62	-50
Demand Response	-15		
Wind	50	50	
Existing Baseload Upgrades	357	230	357
Coal		110	
Gas	213	305	173
Existing Peaking Upgrades	60	60	60
Capacity Purchase	75	75	75

Neither of the load growth sensitivity scenarios selected additional demand response capability. This is likely due to the lumpiness of additions and inability of the model to add exact measures of resources as needed. The demand response resource is unable to displace a whole combustion turbine or large capacity purchase due to its relatively smaller size. The high load growth scenario added 110 MW of new baseload coal-fired generation accredited capacity and replaced the Hoot Lake Project with combined cycle generation. The low load growth scenario did not add any wind and added slightly less simple cycle combustion turbine capacity than the preferred plan. Like the preferred plan, both the high and low load growth scenarios selected the 1.2% CIP level, the Big Stone Plant AQCS project, the Frame 5 oil-fired peaking project, and significant amounts of combustion turbine capacity.

5.3 Environmental Externality Scenarios

The base case optimization model was executed assuming no environmental externality values and no CO_2 tax values. This case is the zero externality scenario. Additional scenarios were evaluated assuming low, mid, and high environmental externality values and CO_2 values. The environmental externality scenarios changed the results of the model in total revenue requirements of the plan and in resources selected as shown in Table 5-4.

The assumptions for the high and low environmental externality values were taken from the June 1, 2010 *Notice of Revised Updated Environmental Externality Values* as provided by the Commission for rural MN. The high and low CO_2 tax values were \$34 and \$9, respectively. For the mid-externality scenario, an average of the high and low values was used. In all externality scenarios, externality and tax values were escalated 3% for inflation and the CO_2 tax began in 2012, replacing the externality value.

As shown, the externality scenarios add significant cost. The low externality scenario was approximately \$706M higher than the preferred plan, however, was identical to the preferred plan in resource selection. The mid and high externality scenarios both replaced the Hoot Lake Project with combined cycle generation. These two plans cost roughly \$1.8B and \$2.8B more than the preferred plan, respectively, due to the impacts of the higher CO_2 tax as well as higher capital costs for new, lower-emitting resources to replace existing resources.

Customers benefit from one uniform plan across the jurisdictions through (1) economy of scale, (2) reduced administrative and ratemaking burden by not having to "jurisdictionalize" the plan, and (3) reduced operational complexity in operating the system. The Company recognizes that the preferred plan may change as CO_2 regulation becomes defined and expiration or extension of the federal PTC for wind generation is determined. The preferred plan provides the greatest flexibility in meeting those changes going forward.

5.4 50% and 75% Conservation and Renewable Scenarios

Minnesota Statutes §216B.2422, Subd. 2 states that "a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources." The calculation is based on the energy from future conservation and renewable resources compared to the total growth in energy requirements for Otter Tail's Minnesota load.

Table 5-4: Comparison of Externality Scenarios to Base Case

Scenario	Base Case	Low Externalities	Medium Externalities	High Externalities
NPVRR ($000)	$4,025,984	$4,731,667	$5,854,719	$6,847,677
Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate				
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind	50 MW Wind	50 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	<100 MW 1-Yr Capacity	<100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	50 MW Wind <150 MW 1-Yr Capacity	50 MW Wind <150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW Capacity	229.7 MW BSP AQCS Project <150 MW Capacity 46.2 MW Combined Cycle	229.7 MW BSP AQCS Project <75 MW Capacity 92.4 MW Combined Cycle
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT	<75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	46.2 MW Combined Cycle 60.0 MW Frame 5s Project	92.4 MW Combined Cycle 60.0 MW Frame 5s Project
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	69.2 MW Frame NG CT <75 MW 1-Yr Capacity	69.23 MW Frame NG CT <75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
New Resources by Category (MW)				
Conservation	-55	-55	-55	-55
Demand Response	-15	-15	-15	-15
Wind	50	50	100	100
Existing Baseload Upgrades	357	357	230	230
Coal				
Gas	213	213	335	341
Existing Peaking Upgrades	60	60	60	60
Capacity Purchase	75	75	75	75

Table 5-5 presents the energy calculation for determining whether the conservation and renewable energy target was met. The 50% scenario is identical to the preferred plan. The 50% and 75% scenarios are shown in Table 5-6 as compared to the base case. Otter Tail's commitment to conservation assists the Company in achieving the 50% target, contributing nearly 44% of the future resources' energy by 2025. The additions of CIP and wind combined in the preferred plan meet 52% of the Company's future energy needs in the Minnesota jurisdiction, assuming only 50% of new wind resources are allocated to Minnesota load. As stated previously this plan's NPVRR was approximately $4.025 B.

Table 5-5: 50% and 75% Renewable and Conservation as Percent of Total New MN Energy Requirements

	50% Renewable and Conservation Scenario			75% Renewable and Conservation Scenario		
	1.2% Conservation (GWh)	MN 50% Share of 50 MW Wind (GWh)	Total (GWh)	1.2% Conservation (GWh)	MN 100% Share of 100 MW Wind (GWh)	Total (GWh)
New MN CIP	482	-	482	482	-	482
New Wind	-	92	92	-	368	368
Total	482	92	574	482	368	850
Percent of Total New MN Energy Requirements (= 1101.341 GWh)	44%	8%	52%	44%	33%	77%

The 75% scenario required forcing the model to select a 1.2% CIP goal in Minnesota and adding 50 MW more wind generation than was selected in the preferred plan. This additional wind was added in 2013 after the expiration of the federal PTC. This plan was more expensive than the base case, reaching $4.077B. Together, the additional CIP and wind achieve 77% of future energy needs in MN.

Otter Tail strives to develop a preferred plan that freely selects least-cost resources and allows Otter Tail to plan and operate the Company as one system that reliably and economically meets the electric needs of its customers and shares the burden of both those costs and benefits among all customers. It is important to recognize in the 75% scenario that the costs for all wind generation additions would be allocated to Minnesota customers to meet this objective. In such a case, the increased revenue requirements would be borne by Minnesota ratepayers.

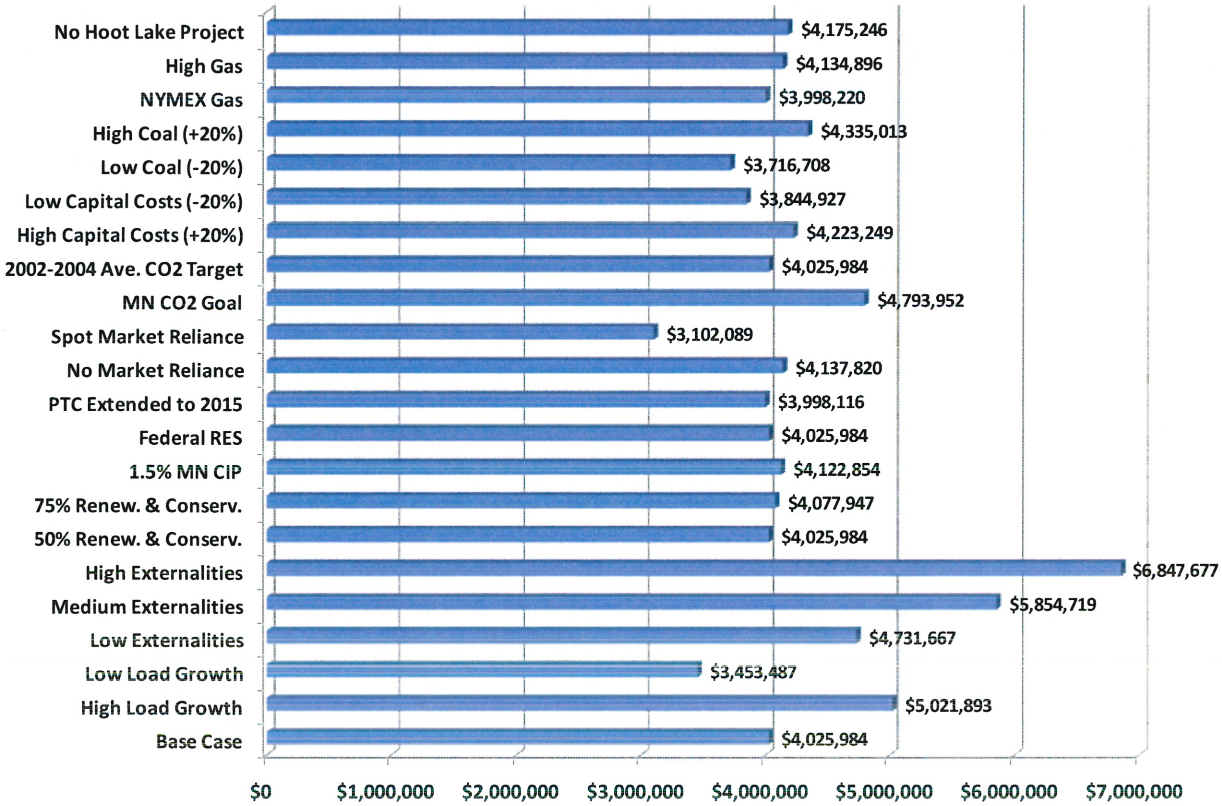
5.5 Additional Sensitivity Scenarios

Otter Tail evaluated additional sensitivity scenarios in the process of selecting a preferred plan. These scenarios included variations in fuel prices, CO_2 reductions, capital costs, and policy or regulation changes. A comparison of the net present value of revenue requirements for all scenarios is provided in Figure 5-4. While some of the sensitivity scenarios are less expensive than the preferred plan, relying on those plans exposes the customer to unacceptable levels of risk. For example, heavy reliance on market purchases and assumptions of low load growth or low fuel and/or capital costs that do not materialize may actually result in higher costs to the customer. Some of the sensitivity scenarios are more expensive than the preferred plan but result in significantly reduced amounts of CO_2. Again, Otter Tail believes that choosing one of these plans as the preferred plan subjects the customer to unacceptable risk levels. Taking actions to attempt to meet uncertain legislative or regulatory requirements could result in the Company taking unnecessary or incorrect actions for which customers are ultimately required to pay.

Table 5-6: Comparison of 50% and 75% Renewable and Conservation Scenarios to Base Case

Scenario	Base Case	50% Renew. & Conserv.	75% Renew. & Conserv.
NPVRR ($000)	$4,025,984	$4,025,984	$4,077,947
Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate			
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind	50 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	50 MW Wind <75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
New Resources by Category (MW)			
Conservation	-55	-55	-55
Demand Response	-15	-15	-15
Wind	50	50	100
Existing Baseload Upgrades	357	357	357
Coal			
Gas	213	213	213
Existing Peaking Upgrades	60	60	60
Capacity Purchase	75	75	75

Figure 5-4: Comparison of Net Present Value of Revenue Requirements for All Sensitivity Scenarios



Comparisons of capacity additions by resource type for all scenarios is presented in Figure 5-5 and Figure 5-6 shows the energy side of the scenarios, presenting GWh by source in the year 2025 for all resources, including new and existing.

Figure 5-7 presents the CO_2 emission levels in tons for all sensitivity scenarios in 2020 as compared with the Company's average levels from 2002-2004. Since no CO_2 legislation with required CO_2 reductions has yet been passed, Otter Tail's strategic priority is to cost effectively plan for future emissions of CO_2 to be no more than the 2002-2004 average level by 2020. The Company's measure for this goal is based on Otter Tail's owned, or internal, emissions. It is assumed that ownership of emissions from purchases will reside with the generator under any type of cap and trade regulation and that the associated costs for those external emissions will be passed to the Company through the price of the energy. As shown in the base case scenario, the model projected emissions in 2020 to be slightly below the 2002-2004 average level. In all years of the study, the preferred plan provides the Company the appropriate resource mix and flexibility to achieve emissions at or below the average CO_2 level emitted from 2002-2004.

Figure 5-5: Comparison of Resource Additions for All Scenarios (MW)

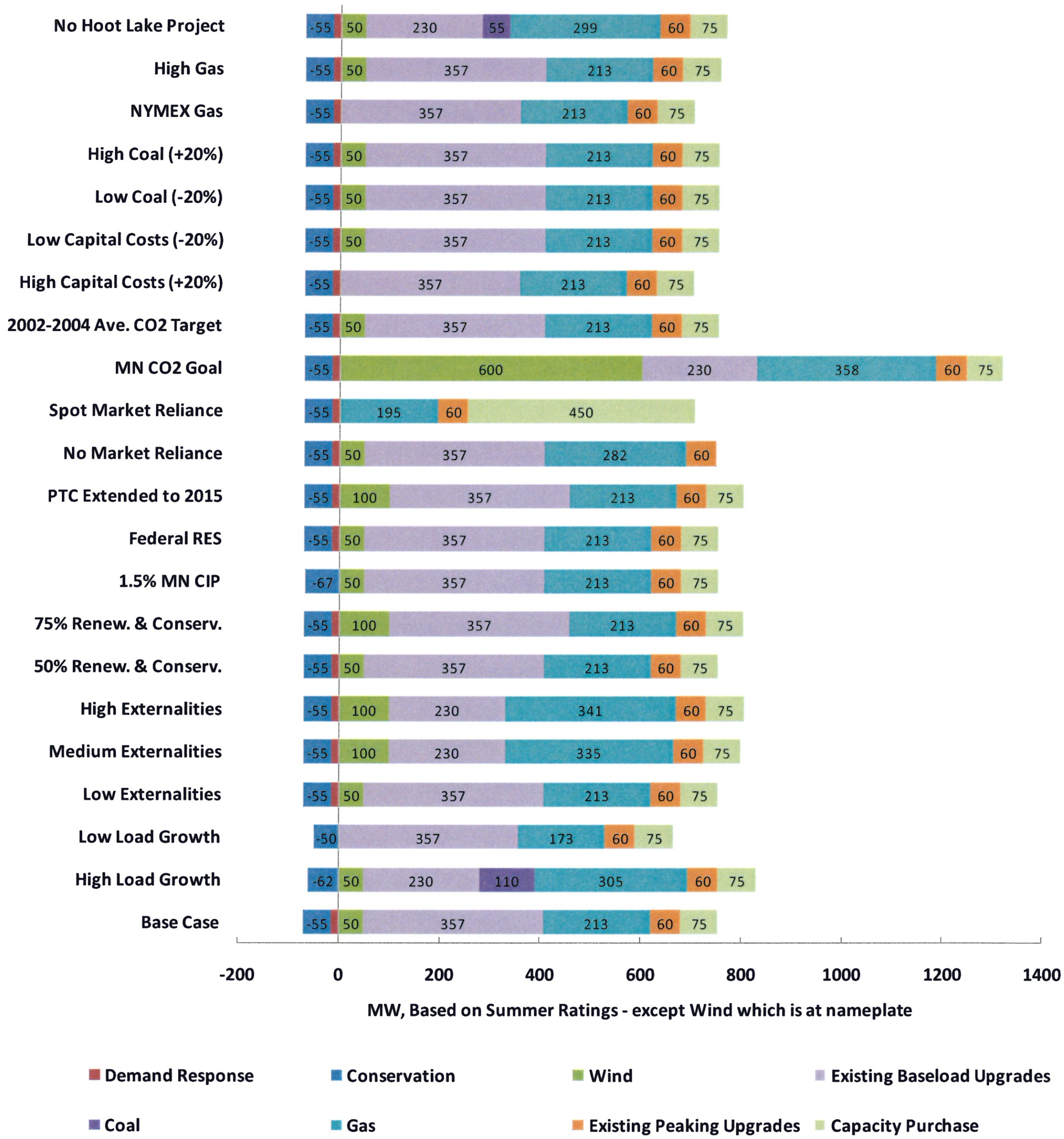


Figure 5-6: Comparison of 2025 Generation (GWh) by Source for All Scenarios

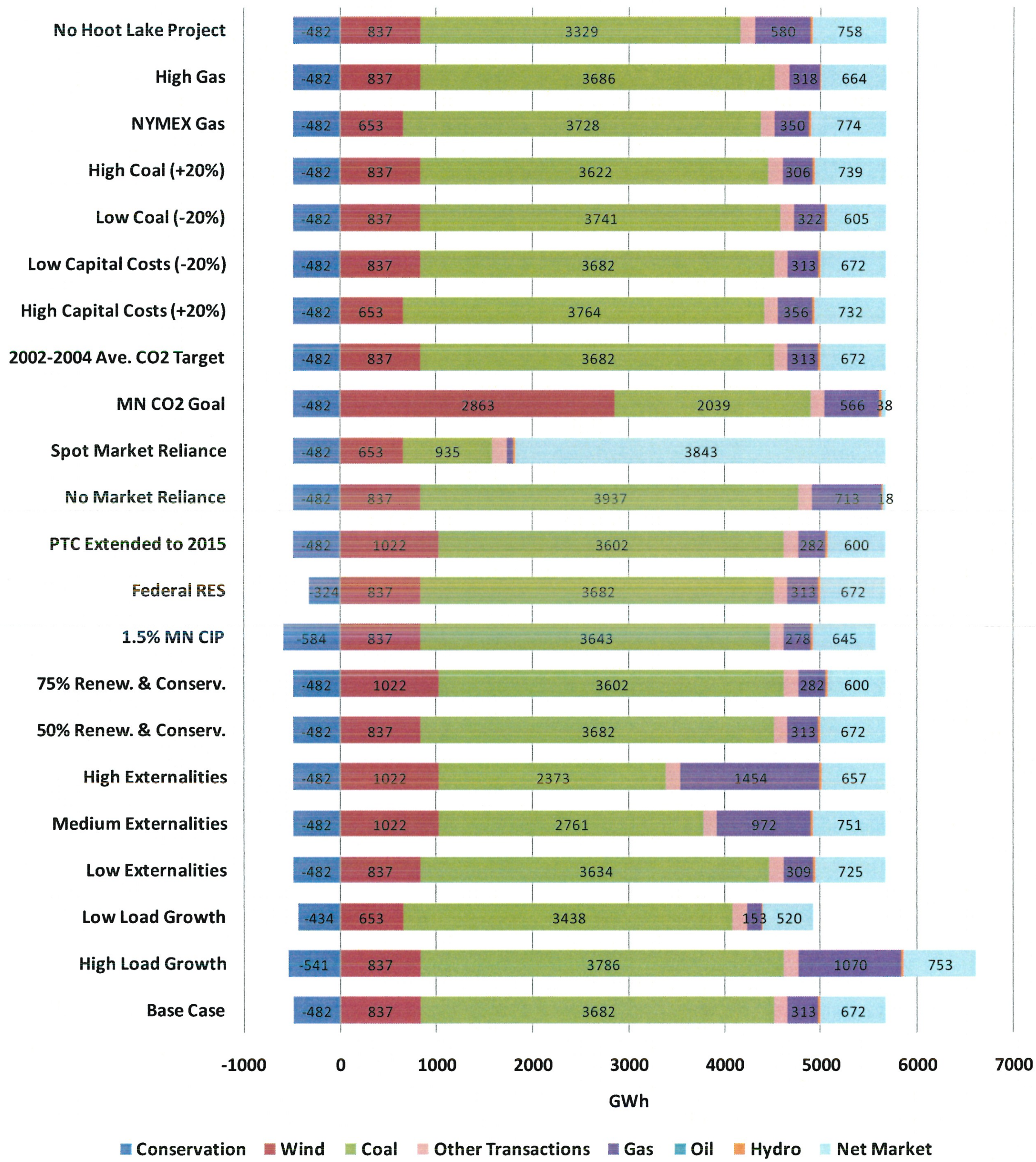
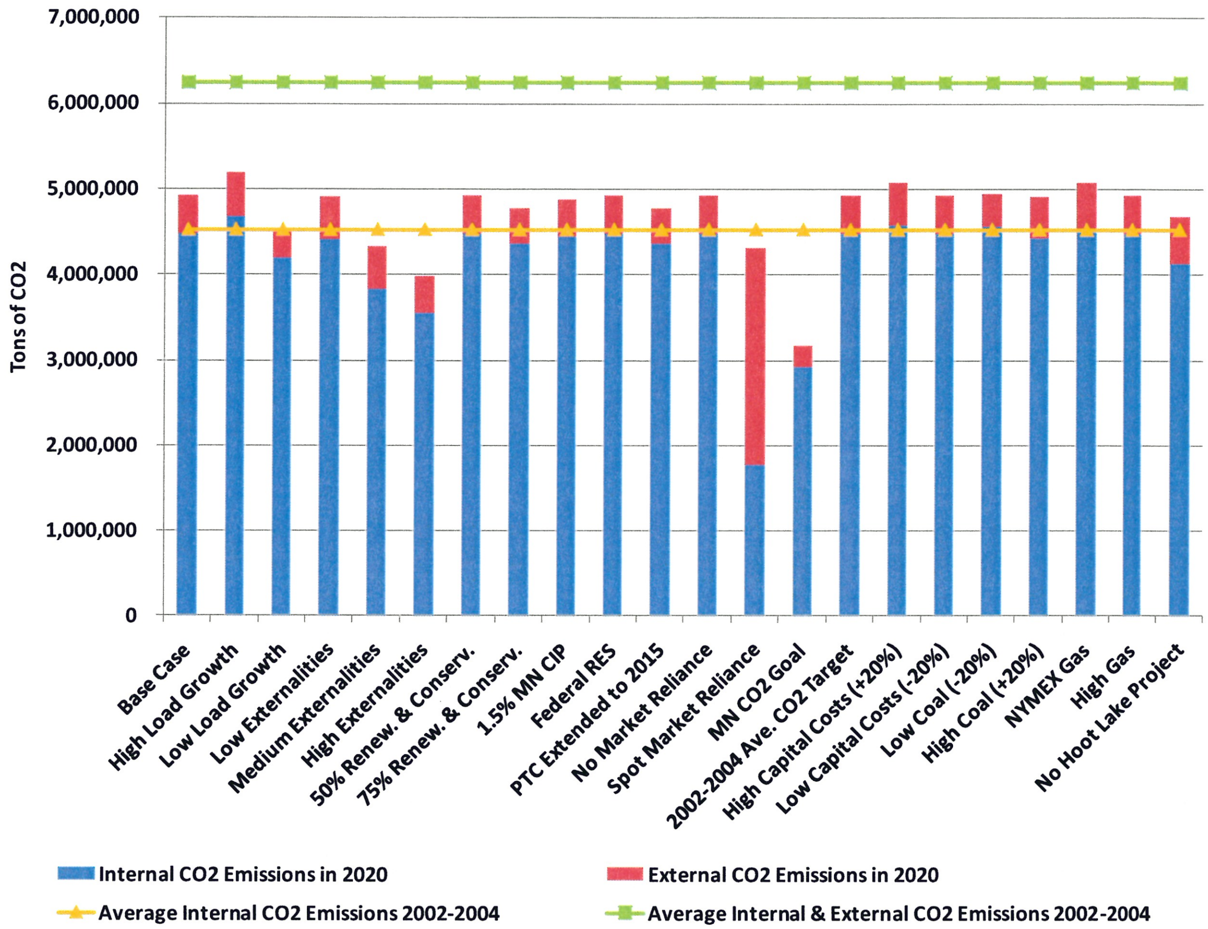


Figure 5-7: Comparison of 2020 CO_2 Emission Levels to 2002-2004 Average for All Sensitivity Scenarios



The following bulleted list provides a brief discussion of each sensitivity scenario in comparison to the preferred plan.

- A 1.5% Minnesota CIP achievement scenario – By forcing the 1.5% Minnesota CIP goal into the model, the results showed additional costs of approximately $97M over the preferred plan, or base case. This scenario added no demand response to the resource alternatives, but otherwise was similar to the preferred plan.

- A 15% federal RES by 2025 –This scenario showed no difference from the preferred plan.

- Extension of the federal PTC through 2015 – This scenario showed a lower net present value of revenue requirements than the preferred plan by about $28M and added an additional 50 MW of wind above the preferred plan. The rest of the resource additions in this plan were similar to those in the preferred plan.

- No market reliance – This scenario was about $112M higher than the preferred plan. The Company has historically relied on the market, to some extent, to achieve savings and keep customer rates low. The Company can achieve lower costs for customers by relying on the market in a responsible manner as in the preferred plan. The energy import level in the preferred plan is 12% of total retail sales in 2025 and includes energy purchases to cover for major outages for maintenance of generation facilities.

- Unlimited spot market reliance – The price forecasts for capacity and energy indicate a surplus market. If the Company allowed unlimited spot market reliance, the reduction in net present value of revenue requirements from the preferred plan could be a significant $924M. As shown, this plan would require Otter Tail to purchase capacity at a very high level throughout the study period and would import nearly half of the system's energy requirements by 2025. This plan would build about 195 MW of natural gas-fired simple cycle combustion turbine peaking capacity, pursue a 1.2% goal for CIP in Minnesota and implement new demand response programs. No wind would be built, and the Hoot Lake Plant project and Big Stone Plant AQCS project would not occur. However, Otter Tail chooses to limit exposure to market fluctuations by limiting capacity and energy market reliance for reliability purposes and risk mitigation. The significance of the savings associated with this scenario support the Company's position to allow a prudent level of market reliance with the intent to minimize both cost and risk.

- Minnesota CO_2 Goal – According to Statute §216H.02, Minnesota has stated goals of achieving a 15% reduction in CO_2 emissions from 2005 levels by 2015, a 30% reduction by 2025, and an 80% reduction by 2050. This scenario would be roughly $768M more expensive than the preferred plan, largely due to capital expenditures on wind and gas resources to replace baseload coal generation. The significance of the costs associated with this scenario support the Company's position to cost effectively plan for future internal CO_2 emissions to be no more than 2005 levels by 2020 until CO_2 regulation certainty exists.

- 2002-2004 Average CO_2 Emission Target – Otter Tail's objective is to economically plan for internal emissions of CO_2 to not exceed the average level emitted from 2002-2004 by 2020. This scenario limited CO_2 emissions to the 2002-2004 average level throughout the study period and the results were identical to the base case.

- High capital costs (+20%) – Assuming that capital costs of wind generation and thermal resource alternatives were 20% higher than in the base case scenario resulted in a higher cost of roughly $200M. The resources selected in this scenario were similar to the preferred plan except that this scenario did not add any wind generation.

- Low capital costs (-20%) – Assuming that capital costs of thermal resource alternatives were 20% lower than in the base case scenario resulted in a lower cost by approximately $181M. The resources selected in this scenario were identical to the preferred plan.

- Low coal (-20%) – Assuming coal prices are 20% less than in the base case scenario resulted in a lower NPVRR by about $309M. This scenario was identical to the preferred plan, or base case scenario, in resource selection.

- High coal (+20%) – Assuming coal prices are 20% higher than in the base case scenario resulted in a higher cost by around \$309M. This scenario selected the same resources as the preferred plan.

- A NYMEX gas price scenario as provided by Wood Mackenzie – The gas prices in this scenario were based on an alternative gas price forecast that was slightly higher in the early years and lower in the majority of the outer years of the study period. This scenario was slightly less expensive than the preferred plan by about \$28M and added no wind to the resource alternatives, but otherwise was similar to the preferred plan.

- High gas prices (+20%) – Assuming gas prices are 20% higher than in the preferred plan resulted in a cost increase of roughly \$109M over the preferred plan. This scenario selected the same resources as the preferred plan.

- The Hoot Lake Project is not available – If continued operation of Hoot Lake is not an option due to impacts of environmental regulation, project infeasibility, or other reasons, this plan selected 86.5 MW of additional simple cycle, natural gas-fired peaking capability and roughly 55 MW of accredited supercritical coal-fired generation capability. This scenario was approximately \$149M more expensive than the preferred plan.

Tables 5-7 through 5-11 show greater detail on the sensitivity scenarios discussed above. In each table the base case is presented on the left for ease in comparison between the sensitivity scenario and the base case.

Table 5-7: Additional Sensitivity Scenarios Compared with Base Case

Scenario	Base Case	1.5% MN CIP	Federal RES	PTC Extended to 2015
NPVRR ($000)	$4,025,984	$4,122,854	$4,025,984	$3,998,116
Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate				
2010	1.2% MN CIP	1.5% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response		New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind	50 MW Wind	
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT 50 MW Wind <100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	50 MW Wind <150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW Capacity	229.7 MW BSP AQCS Project <150 MW Capacity	229.7 MW BSP AQCS Project <150 MW Capacity
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
New Resources by Category (MW)				
Conservation	-55	-67	-55	-55
Demand Response	-15	0	-15	-15
Wind	50	50	50	100
Existing Baseload Upgrades	357	357	357	357
Coal				
Gas	213	213	213	213
Existing Peaking Upgrades	60	60	60	60
Capacity Purchase	75	75	75	75

Table 5-8: Additional Sensitivity Scenarios Compared with Base Case (continued)

Scenario	Base Case	No Market Reliance	Spot Market Reliance	MN CO2 Goal
NPVRR ($000)	$4,025,984	$4,137,820	$3,102,089	$4,793,952
Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate				
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response	New Demand Response 50 MW Wind
2012	50 MW Wind	50 MW Wind		100 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	150 MW Wind <75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <375 MW 1-Yr Capacity	<100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	100 MW Wind <150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW Capacity	<375 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity 46.2 MW Combined Cycle
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT 69.23 MW Frame NG CT	<450 MW 1-Yr Capacity	69.2 MW Frame NG CT 150 MW Wind <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT	<450 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project	60.0 MW Frame 5s Project <450 MW 1-Yr Capacity	60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity		86.5 MW Aero NG CT 69.2 MW Frame NG CT	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	69.2 MW Frame NG CT <75 MW 1-Yr Capacity 50 MW Wind
2024	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
New Resources by Category (MW)				
Conservation	-55	-55	-55	-55
Demand Response	-15	-15	-15	-15
Wind	50	50		600
Existing Baseload Upgrades	357	357		230
Coal				
Gas	213	282	195	358
Existing Peaking Upgrades	60	60	60	60
Capacity Purchase	75		450	75

Table 5-9: Additional Sensitivity Scenarios Compared with Base Case (continued)

Scenario	Base Case	2002-2004 Ave. CO2 Target	High Capital Costs (+20%)	Low Capital Costs (-20%)
NPVRR ($000)	$4,025,984	$4,025,984	$4,223,249	$3,844,927
Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate				
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind		50 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <75 MW Capacity 86.5 MW Aero NG CT
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
New Resources by Category (MW)				
Conservation	-55	-55	-55	-55
Demand Response	-15	-15	-15	-15
Wind	50	50		50
Existing Baseload Upgrades	357	357	357	357
Coal				
Gas	213	213	213	213
Existing Peaking Upgrades	60	60	60	60
Capacity Purchase	75	75	75	75

Table 5-10: Additional Sensitivity Scenarios Compared with Base Case (continued)

Scenario	Base Case	Low Coal (-20%)	High Coal (+20%)
NPVRR ($000)	$4,025,984	$3,716,708	$4,335,013
Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate			
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind	50 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
New Resources by Category (MW)			
Conservation	-55	-55	-55
Demand Response	-15	-15	-15
Wind	50	50	50
Existing Baseload Upgrades	357	357	357
Coal			
Gas	213	213	213
Existing Peaking Upgrades	60	60	60
Capacity Purchase	75	75	75

Table 5-11: Additional Sensitivity Scenarios Compared with Base Case (continued)

Scenario	Base Case	NYMEX Gas	High Gas	No Hoot Lake Project
NPVRR ($000)	$4,025,984	$3,998,220	$4,134,896	$4,175,246
Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate				
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind		50 MW Wind	50 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	55 MW Supercritical Coal <75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
New Resources by Category (MW)				
Conservation	-55	-55	-55	-55
Demand Response	-15	-15	-15	-15
Wind	50		50	50
Existing Baseload Upgrades	357	357	357	230
Coal				55
Gas	213	213	213	299
Existing Peaking Upgrades	60	60	60	60
Capacity Purchase	75	75	75	75

Revised 9-17-2010

Appendix B

This replaces the first two pages of 7610.0430 Fuel Requirements and Generation by Fuel Type of the original Appendix B

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2009

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	BIG STONE PLANT	PLANT ID	87004
STREET ADDRESS			
CITY	BIG STONE CITY		
STATE	SD	NUMBER OF UNITS	2
ZIP CODE	57216		
COUNTY	GRANT		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1975	Coal	1587453	
2	STB	IC	1975	FO2	0	
				PLANT TOTAL	1587453	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	256.5	256.5	73.90	93.7	3.3	
2	0.6	0.6				
PLANT TOTAL	257.1	257.1				

D. UNIT FUEL USED

PRIMARY FUEL USE

Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	986,042	Tons	8,376

SECONDARY FUEL USE

Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
REF	2,322	Tons	
FO2	76,093	Gals	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

*** Revised 09/17/2010 ***

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2009

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	COYOTE STATION	PLANT ID	87009
STREET ADDRESS			
CITY	BEULAH		
STATE	ND	NUMBER OF UNITS	1
ZIP CODE	58523		
COUNTY	MERCER		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1981	Coal	856359	
TOTAL						
				PLANT TOTAL	856359	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	150.0	150.0	67.30	75.7	11.3	
PLANT TOTAL	150.0	150.0				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	LIG	698,152	Tons	6,889	FO2	153,733	Gals	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

*** Revised 09/17/2010 ***

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2009

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	HOOT LAKE PLANT
STREET ADDRESS	
CITY	FERGUS FALLS
STATE	MN
ZIP CODE	56537
COUNTY	OTTER TAIL
CONTACT PERSON	Stacie Hebert
TELEPHONE	218-739-8635
PLANT ID	87014
NUMBER OF UNITS	5

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	ST	1948	Coal	-446	Retired as generator
2	USE	ST	1959	Coal	301349	
3	USE	ST	1964	Coal	297789	
2A	STB	IC	1959	FO2	0	
3A	STB	IC	1964	FO2	0	
TOTAL				PLANT TOTAL	598692	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.0	0.0				
2	60.4	60.4	66.20	92.3	5.6	
3	84.7	84.7	46.60	72.7	23.2	
2A	0.2	0.2				
3A	0.2	0.2				
PLANT TOTAL	145.5	145.5				

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	Unit of Measure ****	BTU Content (for coal only)
1	Sub		Tons					
2	Sub	185,008	Tons	9,305	FO2	5,098	Gals	
3	Sub	185,069	Tons	9,319	FO2	70,615	Gals	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2009

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	POTLATCH COGENERATION
STREET ADDRESS	
CITY	BEMIDJI
STATE	MN
ZIP CODE	56601
COUNTY	HUBBARD
CONTACT PERSON	Stacie Hebert
TELEPHONE	218-739-8635

PLANT ID 87030

NUMBER OF UNITS 2

Retired

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	ST	1992	Wood Waste		Retired
				PLANT TOTAL	0	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1						
PLANT TOTAL	0.0	0.0				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	Wood Waste		Tons					

Appendix F

This replaces page 3-4 of the original Appendix F

[TRADE SECRET INFORMATION BEGINS...

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[TRADE SECRET INFORMATION BEGINS...

...TRADE SECRET INFORMATION ENDS]