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October 3, 2012

PUBLIC DOCUMENT - TRADE SECRET AND PRIVILEGED DATA HAS BEEN EXCISED

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

RE: In the Matter of Otter Tail Power Company's 2011-2025 Resource Plan
Docket No. E017/RP-10-623
Baseload Diversification Study 2012-2026

Dear Dr. Haar:

Otter Tail Power Company ("Otter Tail" or "Company") hereby submits it Baseload Diversification Study as ordered in the February 9, 2012 Order in Docket No. E017/RP-10-623.

In order for other parties to have input into what the study would cover, the Company initiated a stakeholder group process at the beginning of the study work. Several group meetings were held, as were individual meetings with all participants. These meetings provided stakeholders a clear understanding of the modeling assumptions used for the study and the details of Otter Tail's recommended plan. Given the advantages of this stakeholder process, Otter Tail respectfully requests an initial comment period that is shorter than the three-month comment period that Minnesota Power had in its Baseload Diversification Study.

This Baseload Diversification Study and Appendix B, Appendix C, Appendix E and Appendix F contain confidential business information that is considered proprietary. These sections have been marked NONPUBLIC DOCUMENT – CONTAINS TRADE SECRET AND PRIVILEGED DATA 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 generally known to or accessible to the public.

PUBLIC copies or NONPUBLIC copies (as appropriate) have been distributed to all persons on the attached service list by electronic service or by First Class mail. The PUBLIC version will also be posted on the Company's website at www.otpco.com.

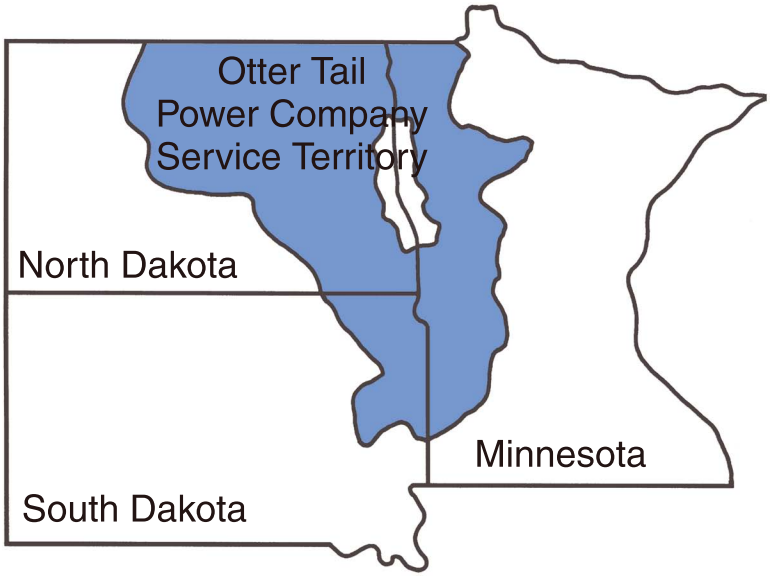
Otter Tail respectfully requests that the Commission approve its Baseload Diversification Study. Should you have any questions, please contact me at (218) 739-8417 or bhdraxten@otpco.com.

Sincerely,

/s/ BRIAN DRAXTEN
Brian Draxten
Manager, Resource Planning

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

Baseload Diversification Study 2012-2026



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TRADE SECRET AND PRIVILEGED DATA HAS BEEN EXCISED

Submitted to
Minnesota Public Utilities Commission

October 3, 2012
Docket No. E017/RP-10-623

OTTER TAIL POWER COMPANY

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Otter Tail Power Company's 2012-2026 Resource Plan Compliance Filing	DOCKET NO. E017/RP-10-623 **OTTER TAIL POWER COMPANY'S HOOT LAKE BASELOAD DIVERSIFICATION STUDY 2012-2026**

I. EXECUTIVE SUMMARY

The Minnesota Public Utilities Commission ("MPUC") approved Otter Tail Power Company's ("Otter Tail's" or "Company's") 2012-2026 Integrated Resource Plan February 9, 2012, but ordered that "within nine months…the Company shall file a baseload diversification study, with a specific focus on evaluating retirement and repower options for the Hoot Lake Plant…"

To comply with the order Otter Tail Power Company evaluated three scenarios:

1. *Scenario 2015 – Expedited Retirement*: Retire Hoot Lake Plant in 2015 to avoid the costs of complying with Mercury and Air Toxics Standards and replace with natural gas generation.

2. *Scenario 2020 – Expected Retirement*: Add equipment to comply with Mercury and Air Toxics Standards by 2015 and plan to retire the plant in 2020.

3. *Scenario 2040 – Long-term Coal Operation*: Refurbish the plant for long-term operation.

Study results show the lowest cost option to be *Scenario 2020 - Expected Retirement*: Add pollution control equipment to comply with Mercury and Air Toxics Standards ("MATS") by 2015 and plan to retire Hoot Lake Plant in about 2020, likely replacing it with natural gas generation.

Hoot Lake Plant today

Hoot Lake Plant's two operating coal-fired generation units, Unit #2 (60 MW) and Unit #3 (80 MW), came on line in 1959 and 1964 respectively and produce approximately 20 percent of Otter Tail Power Company's generation. Hoot Lake Plant is one of Otter Tail's most reliable

plants and routinely has higher availability than similarly sized units nationwide as measured by the National Energy Regulatory Corporation's ("NERC") Generating Availability Data System. A 1000-kw hydro power unit is adjacent to the coal-fired units.

Both coal units burn low-sulfur western sub bituminous coal. Both were retrofit in 1972 with precipitators that remove more than 98 percent of the fly ash. MATS, finalized December 2011 by the EPA, requires that these precipitators be upgraded by 2015. Both units also include low-NOx burners that reduce nitrogen oxide emissions by about 60 percent.

Report recommendation

Otter Tail Power Company used Strategist modeling to assess the sensitivity of each scenario to variations in natural gas prices, CO_2 costs, delivered coal prices, and load growth. Otter Tail also employed an extensive stakeholder process to consider modeling assumptions, local socioeconomic impacts, the timing of rate increases for customers, and public policies in the three states the Company serves.

As a result, Otter Tail recommends *Scenario 2020 – Expected Retirement*. Using the MPUC guidelines for CO_2 the study shows *Scenario 2040 – Long-term Coal Operation*, refurbishing Hoot Lake Plant to run as a coal plant beyond 2020, to cost more than the other alternatives. Although *Scenario 2020 - Expected Retirement* (upgrading the electrostatic precipitator components at the plant to comply with MATS by 2015) is least cost in the majority of sensitivities, the difference between it and *Scenario 2015 – Expedited Retirement* (retiring Hoot Lake Plant as a coal plant in 2015 and repowering with natural gas) is less dramatic under certain sensitivities. Given the volatility of natural gas prices and the uncertainty of CO_2 legislation or regulation, however, customers should benefit from a plan that minimizes capital expenditures for constructing a new natural gas unit until decision makers have more natural gas price history and information about environmental regulations, particularly for CO_2. Likely even a bigger factor in the decision is that *Scenario 2020 – Expected Retirement* minimizes costs to customers for Hoot Lake Plant at a time when they will see bill increases due to required environmental upgrades already underway at Big Stone Plant.

II. INTRODUCTION

Otter Tail hereby submits its Baseload Diversification Study in compliance with the Minnesota Public Utilities Commission February 9, 2012, ORDER APPROVING PLAN SUBJECT TO CONDITIONS, REQUIRING FURTHER FILINGS, AND SETTING REQUIREMENTS FOR NEXT RESOURCE PLAN in Docket No. E017/RP-10-623 ("Order"). Ordering Paragraph 2 of that Order requires:

> *Within nine months of the date of this order, the Company shall file a baseload diversification study, with a specific focus on evaluating retirement and repower options for the Hoot Lake Plant. That study shall include analysis of the transmission planning implications of all options studied, shall begin with 2011/2012 natural gas costs in analyzing natural gas generation options, and shall set forth the Company's analysis of the costs of all Environmental Protection Agency regulations that affect its operations and its plans for compliance.*

This study documents the analysis performed to comply with the MPUC Order. Otter Tail Power Company's current capacity resources include 68 percent coal generation (See Figure 18). No environmental regulations currently require significant capital upgrades at Otter Tail's Coyote Plant, and decisions on Big Stone Plant were made in Otter Tail's current IRP and recently completed Advanced Determination of Prudence case in Minnesota. Therefore, this study will focus on Hoot Lake Plant.

While this study is called a baseload "*diversification*" study, in Otter Tail's view it is more a baseload "*transition*" study. The eventual replacement for Hoot Lake Plant will be natural gas generation. Otter Tail studied scenarios that address the timing of the replacement..

As required by the MPUC Order, this study provides a focused evaluation of the retirement and repowering options for Hoot Lake Plant. More specifically, it examines the following three retirement and repowering scenarios:

(1) <u>*Scenario 2015 – Expedited Retirement*</u>: This scenario assumes that Otter Tail will commence immediately with activities necessary for an early retirement of Hoot Lake Plant in 2015. This is the earliest date by which the facility could reasonably be retired and replaced.[1] On one hand, retirement by 2015 allows Otter Tail to avoid a $10 million investment required to comply with the MATS rule. On the other hand, it requires Otter Tail to expend $226 million prior to 2020 necessary to construct replacement resources.

[1] In fact, completing all permitting, procurement, and construction activities for immediate retirement/replacement may not be possible by 2015 without expedited regulatory proceedings. Ultimately, depending upon the duration of the required regulatory proceedings, an expedited retirement may not be fully accomplished until 2016.

(2) *Scenario 2020 – Expected Retirement*: This scenario plans for a retirement of Hoot Lake Plant by 2020. This duration is consistent with Otter Tail's current planning horizon for the facility. It requires the $10 million MATS investment and defers the expenditures necessary for plant replacement by five years. Deferring the replacement expenditures also prevents an overlapping of these capital expenditures and the corresponding rate increases with the capital expenditures for the Air Quality Control System at Otter Tail's Big Stone Plant.[2]

(3) *Scenario 2040 – Long-term Coal Operation:* This scenario assumes preparation for a full refurbishment of the facility for long-term continued operation. This scenario assumes that Otter Tail would install equipment to meet the MATS requirement in 2015 and an additional $125 million to meet likely environmental regulations and upgrade existing equipment for reliable operation for another 20 years.

Additional details for each of these scenarios are provided throughout this study, including a discussion of the replacement facilities that would be expected for the 2015 and 2020 retirement scenarios.

Otter Tail used Strategist modeling to evaluate the cost effectiveness of each scenario. That modeling evaluated each scenario's sensitivity to variations in gas prices, CO_2 costs, coal costs, and load growth. Otter Tail modeled 42 sensitivities for each of the three scenarios for a total of 126 Strategist modeling runs.

As part of this study, Otter Tail employed a stakeholder process to engage interested participants in the assumptions, methodology, analysis, and results. The first stakeholder group meeting was actually held prior to receiving the final written order in Otter Tail's 2010 IRP and continued throughout the study process. The organizations that participated in the stakeholder process included:

- Minnesota Public Utilities Commission Staff.
- Minnesota Department of Commerce, Division of Energy Resources.
- North Dakota Public Service Commission Staff.
- South Dakota Public Utilities Commission Staff.
- Minnesota Center for Environmental Advocacy.
- Izaak Walton League of America.
- Sierra Club.
- Fresh Energy.
- Minnesota Chamber of Commerce.

[2] The MPUC granted an Advance Determination of Prudence for the Big Stone Plant AQCS project on January 23, 2012 in Docket No. E017/M-10-1082.

- Minnesota Pollution Control Agency.
- Minnesota Attorney General's Office.
- North Dakota Large Industrial Group (attended final meeting).
- City of Fergus Falls (attended final meeting).
- Otter Tail Valley Railroad (attended final meeting).

III. BACKGROUND

A. Description of Otter Tail Power Company

Otter Tail Power Company began utility operations in 1909. It currently serves 129,300 customers in a 70,000-square-mile rural area of Minnesota, North Dakota, and South Dakota. About 60,600 of Otter Tail's customers reside in Minnesota (which is 47 percent of the total).

Otter Tail serves 423 small communities with an average population of 400. Only three Otter Tail communities have populations over 10,000: Jamestown, North Dakota – 15,527; Fergus Falls, Minnesota – 13,949; and Bemidji, Minnesota – 13,074.

Figure 1 - Map of Otter Tail service territory and large generation facilities

The breakdown for Otter Tail's Minnesota customers by customer class is as follows:

Figure 2 - 2011 Minnesota Customers and mwh

Residential:	49,884 - 82%	621,627 mwh - 30%
Commercial:	9,533 - 16%	265,241 mwh - 13%
Industrial:	786 - 1%	1,166,184 mwh - 56%
Other:	363 - 1%	29,470 mwh - 1%

B. Otter Tail's current generation portfolio and anticipated resource needs

Otter Tail's current major generation resources include two shared coal plants (Big Stone Plant and Coyote Station), one solely owned coal plant (Hoot Lake Plant), three owned wind farms (Langdon, Ashtabula, and Luverne), long-term purchased power agreements from two additional wind farms (Edgeley and Langdon), a simple-cycle natural gas combustion turbine (Solway), oil-fired peakers (Jamestown, Lake Preston, and others), and other purchased power agreements. Figure 3 provides a summary of these resources. Big Stone Plant is undergoing an Air Quality Control System ("AQCS") project to meet EPA Regional Haze Regulations, which was reviewed and approved in the Advance Determination of Prudence Docket No. E017/M-10-1082. This total project cost is estimated to cost about $489 million, $264 million of which will be allocated to Otter Tail based upon its ownership share.

Figure 3 - List of Otter Tail's primary generation resources

Coal		Wind		Natural Gas		Fuel oil-fired CTs and engines		Other	
Big Stone Plant (Otter Tail share)	258 MW	Langdon	41 MW	Solway	42 MW	Jmstown 1	21 MW	Hydro	3 MW
Coyote Station (Otter Tail share)	146 MW	Ashtabula	48 MW			Jmstown 2	21 MW		
Hoot Lake Plant	141 MW	Luverne	50 MW			Lake Preston	20 MW	Short-term PPA	106 MW
		Edgeley (PPA)	21 MW			Diesels	4 MW		
		Langdon (PPA)	20 MW						
Total Coal	545 MW	Total Wind	180 MW	Total NG	42 MW	Total Fuel Oil	66 MW		

Otter Tail's current generation mix is illustrated in Figure 3 showing Otter Tail's diverse capacity resources and energy by fuel source. Otter Tail's energy resource mix has changed over the past five years due to the addition of three large wind farms, one each in 2007, 2008, and 2009. This increased Otter Tail's energy from renewable sources to approximately 15 percent.

C. Otter Tail's anticipated generation deficiencies

Figure 4, below, illustrates Otter Tail's forecasted capacity deficiencies during the next 15 years by comparing the forecasted demands of Otter Tail's customers with the capacity of Otter Tail's existing generation resources.

Figure 4 - Table of forecasted summer capacity deficit with Hoot Lake retiring in 2020 or 2015

Plan Year	50/50 Forecasted Demand (MW)	Accredited Demand Response (MW)	Reserve Obligation Net of Accredited Demand Response (MW)	Aggregate Capacity (ZRCs)	Local Capacity (ZRCs)	Net Transaction Capacity (ZRCs)	Total Accredited Capacity (ZRCs)	Projected Deficiency if HLP Retired in 2020 (-MW)	Projected Deficiency if HLP Retired in 2015 (-MW)
2012	699.9	25.0	700.5	648.2	14.7	100.0	762.9	62.4	62.4
2013	698.0	25.0	698.6	648.2	14.7	100.0	762.9	64.3	64.3
2014	721.6	25.0	723.1	648.2	14.7	100.0	762.9	39.8	39.8
2015	729.0	25.0	730.8	510.9	14.7	100.0	625.6	32.1	-105.2
2016	737.3	25.0	739.4	510.9	14.7	100.0	625.6	23.5	-113.8
2017	746.7	30.0	743.9	510.9	14.7	0.0	525.6	-81.0	-218.3
2018	757.0	30.0	754.6	510.9	14.7	0.0	525.6	-91.7	-229.0
2019	768.2	30.0	766.3	510.9	14.7	0.0	525.6	-103.4	-240.7
2020	780.1	30.0	778.6	510.9	14.7	0.0	525.6	-253.0	-253.0
2021	800.1	30.0	799.4	510.9	14.7	0.0	525.6	-273.8	-273.8
2022	820.0	35.0	814.8	510.9	14.7	0.0	525.6	-289.2	-289.2
2023	840.8	35.0	836.4	510.9	14.7	0.0	525.6	-310.8	-310.8
2024	855.5	35.0	851.7	510.9	14.7	0.0	525.6	-326.1	-326.1
2025	870.7	35.0	867.5	510.9	14.7	0.0	525.6	-341.9	-341.9
2026	886.5	35.0	883.9	510.9	14.7	0.0	525.6	-358.3	-358.3

Figure 4 illustrates that the retirement of Hoot Lake Plant will increase the deficiency in capacity resources by approximately 137.3 MW and shows the capacity deficits that occur under the 2015 and 2020 retirement scenarios examined in this study.

D. Background on Otter Tail's 2011-2025 Integrated Resource Plan

Otter Tail submitted its 2011-2025 integrated resource plan to the MPUC on June 25, 2010. In addition to existing resources, the plan called for more wind energy, natural gas, demand response, and energy efficiency and conservation. The plan did not include new coal resources but did include enhancing pollution control equipment at the Big Stone Plant to meet Regional Haze rules. The plan assumed the Company's two other coal-fired plants--Coyote Station and Hoot Lake Plant--would continue to operate through the study period with upgrades at Hoot Lake Plant in 2019. The MPUC approved the plan February 9, 2012, increasing the amount of new wind resources Otter Tail's plan had recommended and ordering this baseload diversification study.

E. Otter Tail's current rates and anticipated rate increases for capital additions other than those related to the retirement of Hoot Lake Plant

According to the Edison Electric Institute's Typical Bills and Average Rates Report Winter 2012, Otter Tail's current average residential rate for electricity is $0.087/kwh (inclusive of all rider and fuel clause adjustments). This compares to the average for West North Central Investor Owned Utilities at $0.0991 kwh.

Otter Tail's planned near-term capital expenditures are significant, which will increase rates over the next several years. Figure 5 identifies Otter Tail's planned large capital projects and the approximate customer bill impact of each. These capital expenditures will more than double

Otter Tail's existing rate base. The magnitude and timing of the capital required for the Hoot Lake Plant replacement/repowering and the resulting rate impacts are not included in Figure 5. Those issues are the subject of this study.

Figure 5 - Near-term large capital projects

$729 million in capital investments 2012 to 2016		Bill Impact
Routine capital	$ 250 m	0%
Big Stone Plant air quality control system (to meet regional haze requirements)	$ 264 m	15.0%
CapX202 Phase I projects	$ 98 m	5.4%
MISO multi-value projects (BSS-Ellendale, BSS-Brookings, $212m over 10 yr.)	$ 117 m	2.3%

F. History and description of Hoot Lake Plant

Hoot Lake Plant's two operating coal-fired generation units, Unit #2 (60 MW) and Unit #3 (80 MW), came on line in 1959 and 1964 respectively and produce approximately 20 percent of the Company's generation. Unit #1 was a small 7.5 MW (coal) unit that was retired in 2005. A 1000-kilowatt hydro power unit, one of Otter Tail's six hydro units, is immediately adjacent to the coal-fired units.

Both coal units burn low-sulfur western subbituminous coal, approximately 115 train car loads a week. Both units were retrofit in 1972 with electrostatic precipitators that remove approximately 98 percent of the fly ash. The ash byproduct is either recycled and used in applications such as concrete and soil stabilization or stored in an on-site landfill. Both units have low-NOx burners that reduce nitrogen oxide emissions by about 60 percent. The MATS regulation, recently finalized by the EPA and described in more detail below, requires that these precipitators be upgraded by April 15, 2015, with a possible one-year extension to April 15, 2016. The history of Otter Tail's generation at the Hoot Lake site goes back almost 100 years. When Otter Tail's first hydro dam was built in 1914, engineers constructed a diversion dam and tunnel to create two lakes, Hoot Lake and Wright Lake, that are now within Fergus Falls city limits. The elevation drops about 70 feet between Wright Lake and the hydro unit. This elevation difference provided the opportunity for the early hydro facility and it continues to be useful, allowing a unique configuration of gravity flow cooling in Hoot Lake Plant condensers, which helps reduce station load and improves unit efficiency.

G. The three scenarios and how 2020 was established as the planned retirement year for the second scenario

As described earlier, the assessment in this study is based on three retirement/replacement scenarios: *Scenario 2015 - Expedited Retirement*, a premature retirement by 2015; *Scenario 2020 - Expected Retirement*, planning for retirement by 2020; and *Scenario 2040 - Long-term Coal Operation*, refurbishment for continued operations as coal. The first and third scenarios can be

viewed as representing the two ends of the spectrum of retirement options. The first would retire/replace the plant as quickly as could conceivably occur. The third would extend the retirement to the greatest extent reasonably possible.

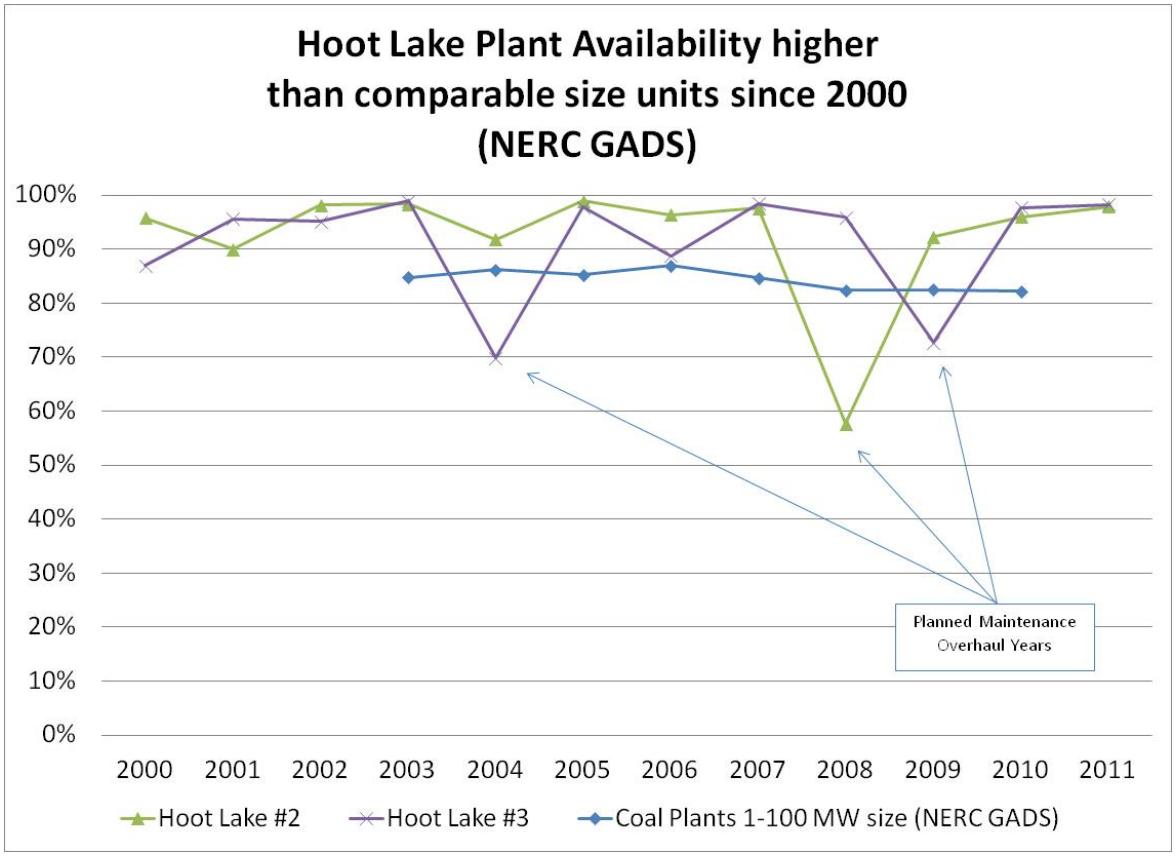
While *Scenario 2020 - Expected Retirement* is based on a retirement occurring very early in the term of evaluation, just five years beyond the earliest reasonably possible retirement, this scenario provides a basis for assessing whether operating the plant with environmental upgrades for a period somewhere between the shortest and longest periods might be advantageous.

The next two sections of this study examine whether the plant's reliability performance or the possibility of environmental regulatory costs indicate a reason to expedite retirement of the facility to some date earlier than 2020. This assessment also helps to illustrate how the 2020 retirement date was established for the second scenario. While it is impossible to predict exactly in what year additional environmental requirements will be put in place, the table below shows there is a low chance of significant environmental regulations that will impact Hoot Lake Plant prior to 2020. After these sections, the study describes the Strategist modeling that was used to compare the cost effectiveness of each of the three scenarios and to assess each scenario's sensitivity to variations in the Strategist input assumptions.

H. Hoot Lake Plant availability performance

When compared to publicly available data from the North American Electric Reliability Corporation Generator Availability Data System (NERC GADS data), the facility continues to perform at or above industry standards with high availability, while operating at high capacity factors. This data, shown in Figure 6, indicates the plant has been reliable.

Figure 6 - Hoot Lake Plant Availability compared to NERC GADS data



I. Existing and potential environmental regulations review for Hoot Lake Plant

This section of the study describes the existing and potential environmental regulations that might affect Hoot Lake Plant before 2020 and Otter Tail's plans for compliance with these regulations. The assessment provides a basis from which to consider whether the risk of material environmental costs indicates that Otter Tail should pursue an expedited retirement of the facility. The assessment is also provided in compliance with the MPUC's specific requirement that this study "set forth the Company's analysis of the costs of all Environmental Protection Agency regulations that affect its operations and its plans for compliance."

Figure 7 below contains an overview of environmental regulations that could impact future operation at Hoot Lake Plant and the likelihood of the regulation having an impact prior to 2020. The impact of the MATS rule, which requires Hoot Lake Plant to improve particulate and mercury control, is discussed in greater detail later in this study. The Clean Water Act Section 316(b) Rule ("CWA 316(b) Rule") and the Cross-State Air Pollution Rule are also discussed below. Additionally, Appendix A contains a detailed discussion of each of the regulations identified in Figure 7.

Figure 7 - Environmental rule impacts to Hoot Lake and likelihood of impact prior to 2020

Rule	Status	Anticipated Hoot Lake Plant Impact	Anticipated Compliance Timeframe	Likelihood of Rule impact prior to 2020 (Capital$)	Likelihood of Rule impact prior to 2020 (Operating$)
Acid Rain Program	Final	Maintain banked allowances (SO2); Operate existing low NOx burners	Ongoing	None	None
2010 SO2 and NO2 NAAQS	Final	Low impact anticipated; Minnesota has no monitored violations	2017 - 2022	Low	Low
Clean Air Interstate Rule	Final	None – Rule stayed for the State of Minnesota	None	None	None
Cross-State Air Pollution Rule	Vacated	Rule would have required SO2 allowance purchases	Unknown	Low	Possible (costs included in analysis starting in 2013)
Regional Haze Program – Best Available Retrofit Technology	Final – EPA Approved MN SIP	None – HLP2 not BART eligible and HLP3 deemed not subject to BART	None	None	None
Regional Haze Program – SIP Revisions	Next MPCA SIP due by July 31, 2018	Likely reductions of SO2, NOx, and PM	Post 2020	Low	Low
Mercury and other Hazardous Air Pollutants (MATS)	Final	Requires PM and mercury reductions, possibly HCl	April 2015	Yes (included in analysis)	Yes (included in analysis)
Minnesota TMDL	Final	70% reduction in mercury air emission; Compliance achieved through MATS	2025	Included (MATS Rule)	Included (MATS Rule)
Greenhouse Gas Regulation – Tailoring Rule	Final	PSD Review for projects that result in a significant net CO_2 increase	No PSD projects planned	Low	Low
Clean Water Act Section 316(b)	Proposed Rule	Unknown – EPA issued a NODA to request further comment on proposed rule. Final rule expected June 2013.	Up to 8 years after final rule	Moderate $0 -$2 million	Moderate
Effluent Guidelines	Proposed Rule Expected Nov. 2012	Unknown	Up to 5 years after final rule	Low	Low
Coal Combustion Residuals	Proposed Rule	Unknown – EPA proposed two significantly different options. Impact to HLP could be low due to managing an active dry ash disposal site with a synthetic liner and leachate collection.	Unknown – pending final rule	Low	Low - additional costs included after 2020

Legend: Air related | Water related | Solid waste related

1. Clean Water Act 316(b) Rule and its potential impact on Hoot Lake Plant

Section 316(b) of the Clean Water Act ("CWA") requires facilities with cooling water intake structures to ensure that the location, design, construction and capacity of the structures reflect the best technology available to minimize harmful impacts on the environment. EPA first promulgated regulations to implement section 316(b) in 1976. In 1977 the U.S. Court of Appeals for the Fourth Circuit remanded these regulations to EPA, which withdrew them and left in place a provision that directed permitting authorities to determine the best technology available for each facility on a case-by-case basis.

Hoot Lake Plant uses once-through cooling except during periods of low water availability and during periods when the water discharge permit requires use of the plant cooling towers. The impact of the Hoot Lake Plant intake structure has been extensively evaluated in two separate studies (conducted in 1976 and 2005), both of which showed minimal impact. In December 1977 the Minnesota Pollution Control Agency ("MPCA"), the Minnesota Department of Natural Resources, and EPA concluded that Hoot Lake Plant's intake structure creates a negligible impact in the aquatic ecosystem and was therefore in compliance with Section 316(b).

After numerous years of proceedings, on April 20, 2011, EPA published proposed national standards for cooling water intake structures at all existing power generating facilities and existing manufacturing and industrial facilities as part of further implementing Section 316(b).

After issuing the proposed rule, EPA received extensive comments and new data, including the two Hoot Lake Plant studies. Consequently, EPA published a Notice of Data Availability ("NODA") on June 11, 2012, to provide further opportunity for comment on the new information and possible revisions to the final rule that EPA is considering. One of the issues EPA is requesting further comment on is establishing an alternative compliance limit for facilities that have low impingement rates, which may be applicable to Hoot Lake Plant.

A final and enforceable 316(b) rule (which applies to cooling water intake systems and is discussed more thoroughly in Appendix A) may have a range of minimal-to-moderate impact on Hoot Lake Plant prior to 2020. The fact that the rule allows for implementation up to eight years after the final rule is published, which would put implentation beyond 2020 for Hoot Lake Plant, indicates that the impact is likely to be minimal. Also, as described above, previous studies have shown that the Hoot Lake Plant cooling system has a minimal impact on the aquatic system. If compliance is ultimately required prior to 2020, the implications for the plant could range from no change to the system, to moderate changes such as a fish barrier net, to full changes such as installing a new cooling tower for Unit #2 (Unit #3 already has a cooling tower). Capital costs for a cooling tower for Unit #2 are estimated to be about $2 million.

2. The Cross-State Air Pollution Rule and its potential impact on Hoot Lake Plant

On July 6, 2010, the EPA proposed a rule, termed the Transport Rule, that would require annual SO_2 and NO_x reductions in 23 states, including Minnesota. EPA attempted to design the rule to address the concerns of the Court with respect to the Clean Air Interstate Rule ("CAIR").

As proposed, the rule required that Otter Tail manage a new set of SO_2 and NO_x allowances separate from the Title IV ARP allowances beginning with calendar year 2012. However, the Transport Rule's impact on Hoot Lake Plant would have been minimal and not required any emissions reductions or allowance purchases. The EPA released the final Transport Rule, renamed the Cross-State Air Pollution Rule ("CSAPR"), on July 8, 2011. The final rule made several changes to the proposed rule, including a substantial change in the allowance allocation methodology, whereby Hoot Lake Plant would need to purchase SO_2 allowances to continue operating at historical levels[3].

A number of states and industry representatives challenged CSAPR, and on December 30, 2011, the D.C. Circuit granted motions to stay CSAPR pending the Court's resolution of the petitions for review. The Court subsequently heard oral argument on April 13, 2012, and issued an order on August 21, 2012 vacating CSAPR. The order requires EPA to continue administering the Clean Air Interstate Rule pending the promulgation of a valid replacement. Because the Court's judgment was pending during the time period this Baseload Diversification Study was being developed, Otter Tail assumed that CSAPR would take effect in 2013. Now that the Court has vacated CSAPR, it would be more appropriate to assume that any costs for compliance with CSAPR will take effect later in the study period. Instead of attempting to predict the likely date for an EPA replacement rule for CAIR, Otter Tail has retained its current assumption that CSAPR will be implemented in 2013. If the CSAPR costs had been removed from the study assumptions or delayed to adjust for this new information, the modeling results described later in this study would reflect somewhat lower costs for continued operation of the plant.

3. Overall conclusions of the environmental regulatory assessment

In general, based upon information known and reasonably estimated as of the submittal of this report, outside of the electrostatic precipitator ("ESP") upgrades and activated carbon injection required by MATS ($10 million in 2015) and the possibility of the 316(b) rule requiring a change to the cooling system, there appears to be a low likelihood of significant environmental compliance implications for Hoot Lake Plant prior to 2020. At some point, depending on future regulatory requirements, which are difficult to predict, it would be reasonable to expect that Hoot Lake Plant may have to meet additional environmental regulations. This was a factor in developing the study scenarios that are considered in this report. The study assumed that, after

[3] As detailed in Otter Tail's initial filing for Docket No. E017/M-12-179.

2020, additional SO_2 and NOx reductions may be required. If so, the plant would have to install new equipment and upgrade the existing plant equipment at the same time.

J. Stakeholder process

The stakeholder process, which included three large group meetings plus individual meetings with each stakeholder group, was beneficial in that it should eliminate some of the discussion and debate that typically occurs around modeling assumptions in resource decision-making. The plan presented in this study is one that balances interests of a diverse stakeholder group with divergent interests. It also has factored in the differences among state jurisdictions and presents a plan that should allow for continued system-wide planning and operation.

IV. STRATEGIST MODELING INPUTS AND ASSUMPTIONS

As indicated earlier in this study, Otter Tail evaluated the following retirement and repowering scenarios for Hoot Lake Plant: (1) *Scenario 2015 - Expedited Retirement*; (2) *Scenario 2020 - Expected Retirement*; and (3) *Scenario 2040 - Long-term Coal Operation.* The following sections of this study provide greater detail of the costs to be incurred for each scenario. The forecasts and other input assumptions used in the strategist modeling are also described in detail, as are the modeling results.

A. Descriptions and capital cost assumptions for each of the three scenarios.

1. Scenario 2015 - Expedited Retirement

This scenario assumes Hoot Lake Plant retires (as a coal-fired resource) in 2015 and is replaced by a natural gas-fired generation resource, as early a retirement of the plant as is reasonably possible. This retirement date corresponds with the date by which Otter Tail will be required to demonstrate compliance with MATS. As described more fully with respect to *Scenario 2020 - Expected Retirement* and *Scenario 2040 - Long-term Coal Operation*, the Company modeled that MATS compliance will require capital expenditures to Hoot Lake Plant of about $10 million. On one hand, retirement by 2015 allows Otter Tail to avoid this $10 million capital expenditure. On the other hand, retirement by 2015 requires the Company to expend $226 million prior to 2020 necessary to construct replacement resources. In order to meet a timeline for immediate replacement, Otter Tail would need to expedite construction of a natural gas line as well as begin permitting immediately for a natural gas-fired generation facility.

2. Scenario 2020 - Expected Retirement

This scenario assumes continued operation of the facility until the 2020 timeframe. The Company would plan for Hoot Lake Plant's limited-life run and retirement in 2020. When compared to *Scenario 2015 - Expedited Retirement,* this scenario assumes the MATS expenditures are incurred by 2015 and it defers by five years the facility retirement and the capital expenditures necessary to construct replacement resources. The deferral assumed in this scenario also avoids overlapping Hoot Lake Plant replacement expenditures with Otter Tail's capital expenditures for the air quality control system project ("AQCS") at Big Stone Plant.

3. Scenario 2040 - Long-term Coal Operation

This scenario assumes that Otter Tail would install equipment to meet the MATS requirement in 2015 and then, rather than retiring in 2020, additional equipment would be added to meet likely environmental regulations and upgrade existing equipment to allow the plant to operate reliably beyond the 15-year planning timeline (the study assumption was 20 years). Otter Tail evaluated the likely environmental control equipment and plant upgrades. The study uses $125 million in air pollution control upgrades and plant condition upgrades.

B. Forecasts and other assumptions used in the Strategist modeling sensitivities.

1. CO_2 cost assessment

Many (42 of the 126 runs) of Otter Tail's Strategist modeling runs were completed using $21.50 per ton for CO_2 costs to comply with the MPUC February 9, 2012, Order in the current IRP. The Wood Mackenzie price forecasts used in the study are based on a CO_2 assumption of $16 per ton beginning in 2023. During the stakeholder process, the Joint Interveners suggested that Otter Tail use a start date of 2016, using $9, $21.50 mid-point, and $34 escalated to 2016 dollars. Also during the stakeholder process, the North Dakota PSC staff, the South Dakota PUC staff, the Minnesota Chamber of Commerce, and the North Dakota Large Industrial Group requested that Otter Tail re-run all sensitivities using a $0 carbon cost. The Company ran all of the sensitivities using both the Wood Mackenzie carbon assumption as well as $0 carbon cost.

Otter Tail also included stakeholder requests for running and analyzing scenarios and sensitivities, including a sensitivity that included CO_2 costs and high coal costs as requested by the Joint Intervenors. Otter Tail also used the Strategist methodology and assumptions that the DOC likely will use in its modeling runs in defining its "Base Case".

2. Energy and fuel price forecasts

Otter Tail used the most recently updated Wood Mackenzie ("W-M") fuel and energy price forecasts (May 2012). During the stakeholder process, discussion of both the price forecasts and the ranges around the forecasts took up a majority of the time in the first two meetings. In the end, Otter Tail's understood that using the W-M price forecasts updated in May 2012 were appropriate and ranges around those forecasts would adequately cover the most extreme range suggested by any stakeholder. Therefore, Otter Tail does not expect modeling assumptions to be a significant issue in this proceeding.

a. Natural gas price forecast

Otter Tail used the Wood Mackenzie May 2012 natural gas price forecast. The ranges modeled as sensitivities were +50 percent, +25 percent, -25 percent, and -50 percent. These ranges are intended to cover extreme variations in future gas prices. See Figure 8 below.

Figure 8 - Wood Mackenzie NG forecast (and sensitivities)

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b. Coal price forecast

The Powder River Basin ("PRB") forecasts were developed using Wood Mackenzie data as a starting point and adjusted to reflect delivery and other basis cost differences specific to Hoot Lake Plant. The ranges for coal prices were -10% / +20%.

Figure 9 - Wood Mackenzie coal forecast with Otter Tail Plant specific shipping costs included

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c. Market capacity and energy

The market energy price forecast was obtained from the Wood Mackenzie May 2012 North American Power Service product. The Wood Mackenzie forecast data was used for 2012 forward. Specific values can be found in Appendix C. Otter Tail allowed these market purchases in its Strategist modeling through 2017 in all sensitivities except the long term market available runs. That sensitivity allowed market energy at purchases through the entire study period.

C. Generation alternatives

Five thermal generation options were entered into Strategist to allow the model to optimize the amount and timing of each generation type. Figure 10 below summarizes the thermal generation alternatives. All resource alternatives and key assumptions are provided in Appendix B. One option is to convert the existing coal-fired plants to natural gas. This is represented in Figure 10 as *HLP to gas*. The estimated cost to convert the boilers to burn natural gas is $12.8 million.

Figure 10 - Generation alternatives entered into Strategist model

Thermal Generation Alternatives					
Name	Scenario 2020 Expected Retirement	Scenario 2040 Long Term Operation	HLP to Gas	Simple Cycle (SC)*	Combined Cycle (CC)*
NamePlate ISO Capacity (MW)	137	137	122	92	146
Fuel	Coal	Coal	Natural Gas	Natural Gas	Natural Gas
Capital Costs (2012$)	$ 9,179,000	$ 125,492,000	$ 12,810,000	$ 52,900,000	$ 153,884,000
Capital Costs ($/kw)	$ 67.00	$ 916.00	$ 105.00	$ 575.00	$ 1,054.00
Capital Escalation	4%	4%	4%	4%	4%
Total Fixed O&M (2012$)	$ 6,612,334	$ 10,008,583	$ 2,432,000	$ 694,980	$ 1,961,190
2012 Variable O&M ($/mwh)	$ 0.36	$ 0.36	$ 1.30	$ 2.50	$ 2.80
Available Years	2015	2020	2015	2016-2026	2016-2026
Operating Life (years)	5	20	5	20	20
Available Scenario	2020, 2040	2040	2020	2015, 2020, 2040	2015, 2020, 2040
	* For the simple cycle (SC) and combined cycle (CC) alteratives, the capacity, capital costs, and fixed O&M are based on the Company having 50% ownership of a generic project				

Scenario 2020 - Expected Retirement which plans for retirement of Hoot lake Plant in 2020, was modeled at $10 million in 2015 and represents electrostatic precipitator upgrades needed to meet the MATS requirement if both units were modified. However, Hoot Lake Plant may be able to meet MATS by the site averaging provision with an upgrade at Unit #3 only. The approximate cost of only upgrading Unit #3 is just greater than half of the $10 million modeling input. However, to allow for some contingency for the possibility that site averaging is not preferred, Otter Tail used $10 million to cover electrostatic precipitator upgrades to both units.

Scenario 2040 - Long-term Coal Operation includes capital expenditures for additional SO_2 and NOx control, as well as an investment in general plant upgrades necessary to assume 20 years of additional operating life.

The costs listed above for both the simple cycle (SC) and combined cycle (CC) represent one-half of the total cost of a larger plant. For example, the combined cycle plant that is represented in the table above is actually based on costs for a 1x1 F-Class combined cycle that would be 292 MW (summer rating) and total cost of $307.8 million. This was a factor in determining what level of total transmission may be needed at the site for the transmission study that follows. Using the costs of a larger gas unit gives an advantage to natural gas generation in the Strategist modeling allowing Otter Tail to take advantage of the economies of scale of a large plant.

D. Transmission considerations and cost inputs

The MPUC Order requiring this baseload diversification study specifically indicated that the study "shall include analysis of the transmission planning implications of all options studied." In compliance with that requirement, Otter Tail analyzed:

- The implication for area transmission if Hoot Lake Plant were shut down as an electric generation plant and no replacement generation was constructed at the Hoot Lake site.
- The new transmission and upgrades that would be required if Hoot Lake Plant were replaced with a larger natural gas fired unit at the Hoot Lake site.

The following sections summarize this analysis, and Appendix B provides additional description and information of this transmission analysis.

1. Transmission implications for 2015 Hoot Lake Plant retirement

Otter Tail has completed studies to gain insight into transmission reliability concerns related to Hoot Lake Plant's being retired as a generation unit. Without the current generating facility at the site, voltage levels on the transmission system below acceptable criteria would occur during the 2016 summer peak season. The likely mitigation measure would be to install capacitor banks near the Hoot Lake site for an estimated cost of **[TRADE SECRET DATA BEGINS... … TRADE SECRET DATA ENDS]**.

2. Transmission costs for additional natural gas generation at the Hoot Lake site

New generation at the Hoot Lake site likely would be natural-gas fired. Consequently, Otter Tail based its study on a1x1 F-class combined cycle 300 to 400 MW plant. The study assumed that, because the existing Hoot Lake plant was retired, the first 140 MW of generation would require no additional transmission upgrade cost. Analysis showed that the estimate for a transmission plan for operation of up to 400 MW at the site would result in upgrade costs of about **[TRADE SECRET DATA BEGINS... … TRADE SECRET DATA ENDS]**.

V. STRATEGIST RESULTS OF SCENARIOS

A. Base case

After defining the three scenarios that would be considered with regard to the continuing operation of Hoot Lake Plant, Otter Tail set its "base case" using the following assumptions as ordered by the MPUC on February 9, 2012 in the current IRP to determine the base case.

- Limit market purchases to the first 5 years of the plan.
- Set the energy efficiency goal at 1.2 percent.
- Use the equivalent wind capacity credit that is received in the MISO Module E.
- Use the midpoint of the MPUC's range for CO_2 of $21.50 beginning in 2012.
- Include sulfur dioxide and nitrogen oxide costs in the base case.

The base case contains important energy and fuel cost assumptions, which were included in a forecast purchased from Wood Mackenzie as updated in May 2012.

- Natural gas price – Wood Mackenzie
- Coal price – Wood Mackenzie with Otter Tail plant specific shipping costs
- Wholesale energy and capacity costs – Wood Mackenzie

All of these base assumptions above were entered into the Strategist model. Various sensitivities were set up to test each scenario and develop a matrix of results. The following section discusses those sensitivities and the resultant Strategist modeling output.

B. Strategist modeling results

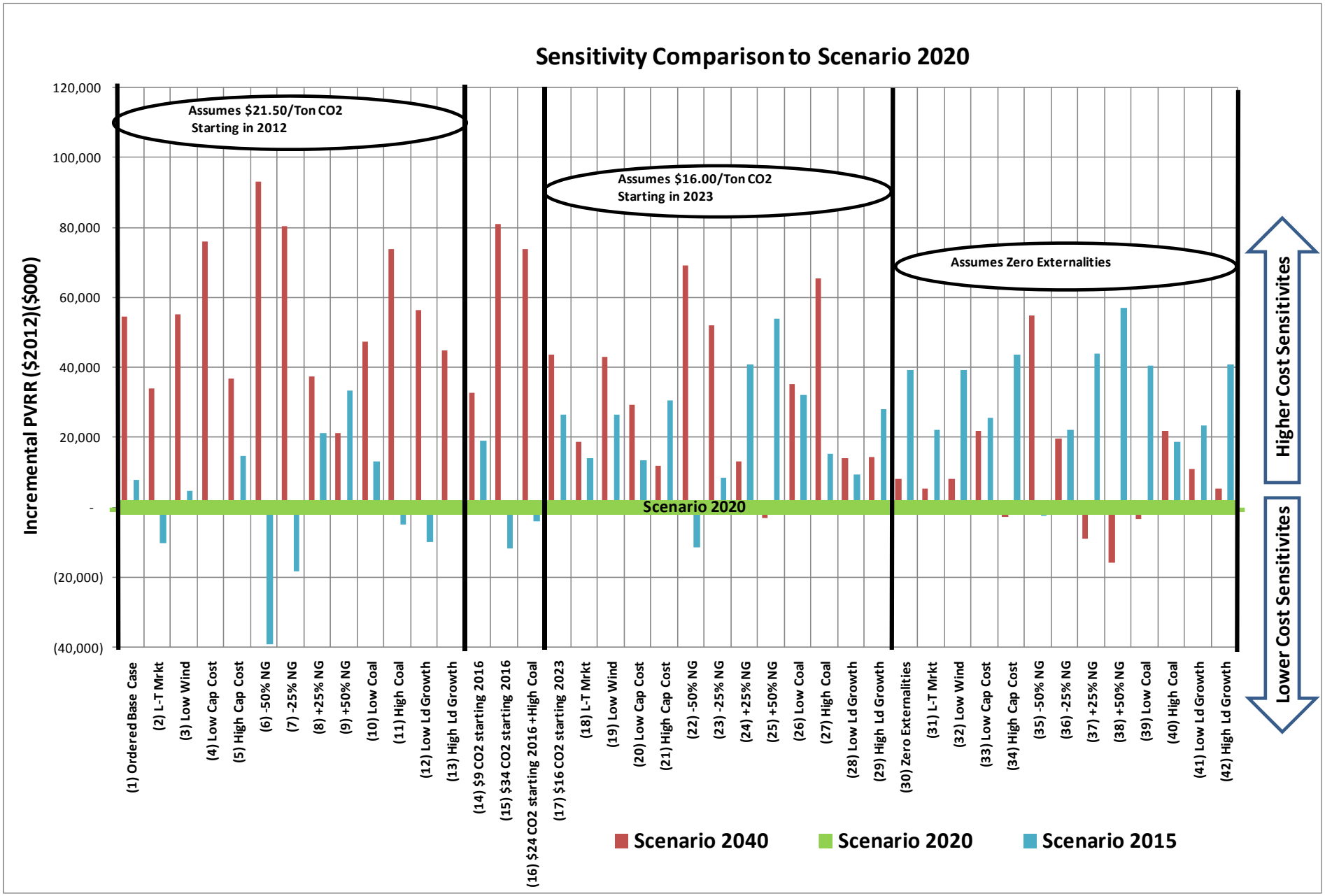
Otter Tail completed capacity expansion modeling using Strategist as ordered by the MPUC. The three scenarios each with 42 sensitivities resulted in 126 Strategist runs. Appendix D contains detailed results of each of the runs, and Appendix C contains the key modeling assumptions.

Comparing various modeling results from Strategist and "ranking" resource selection plans is done by comparing the PVRR (Present Value of Revenue Requirements) over the planning period. In Figure 11, the PVRR cost comparisons are shown for each scenario and sensitivity. The green line represents the PVRR for *Scenario 2020 - Expected Retirement* and is used as the baseline for comparison purposes. The blue bar represents cost differences compared to the baseline for *Scenario 2015 - Expedited Retirement* and the red bar represents cost differences compared to the baseline for *Scenario 2040 - Long-term Coal Operation*. For example, the base sensitivity indicates both *Scenario 2015 - Expedited Retirement* and *Scenario 2040 - Long-term Coal Operation* to be more expensive than *Scenario 2020 – Expected Retirement* by approximately $8 million and $55 million respectively. If the blue or red bar is above the green axis, the plan is shown to be more expensive than the *Scenario 2020 - Expected Retirement* plan. If it is below the green axis, it is less expensive than *Scenario 2020 - Expected Retirement.*

One shortcoming of sensitivity analysis as shown in Figure 11 is that all 126 sensitivities appear to have equal weightings. In other words, the probability of a certain scenario actually occurring is not taken into account. For instance, there is an extremely low chance that any legislation or regulation regarding CO_2 costs could pass and be implemented in 2012. Yet, almost 25% of the runs included are on that basis. Likewise, some of the very extreme cases like natural gas prices being 50% over or 50% below our price forecast is very unlikely.

Despite assumptions used in the sensitivities that would generally support lower costs for an earlier retirement, the vast majority of sensitivity results still support the expected retirement in 2020 as being lower cost. In only the extreme sensitivities (i.e.; minus 50% natural gas pricing) or sensitivities with $21.50 CO_2 costs is there much cost competitiveness for an expedited retirement. As more realistic CO_2 assumptions are used, *Scenario 2020 - Expected Retirement* becomes even more cost effective. The various sensitivities and results are described in more detail following Figure 11.

Figure 11 - Summary graph of incremental PVRR between scenarios

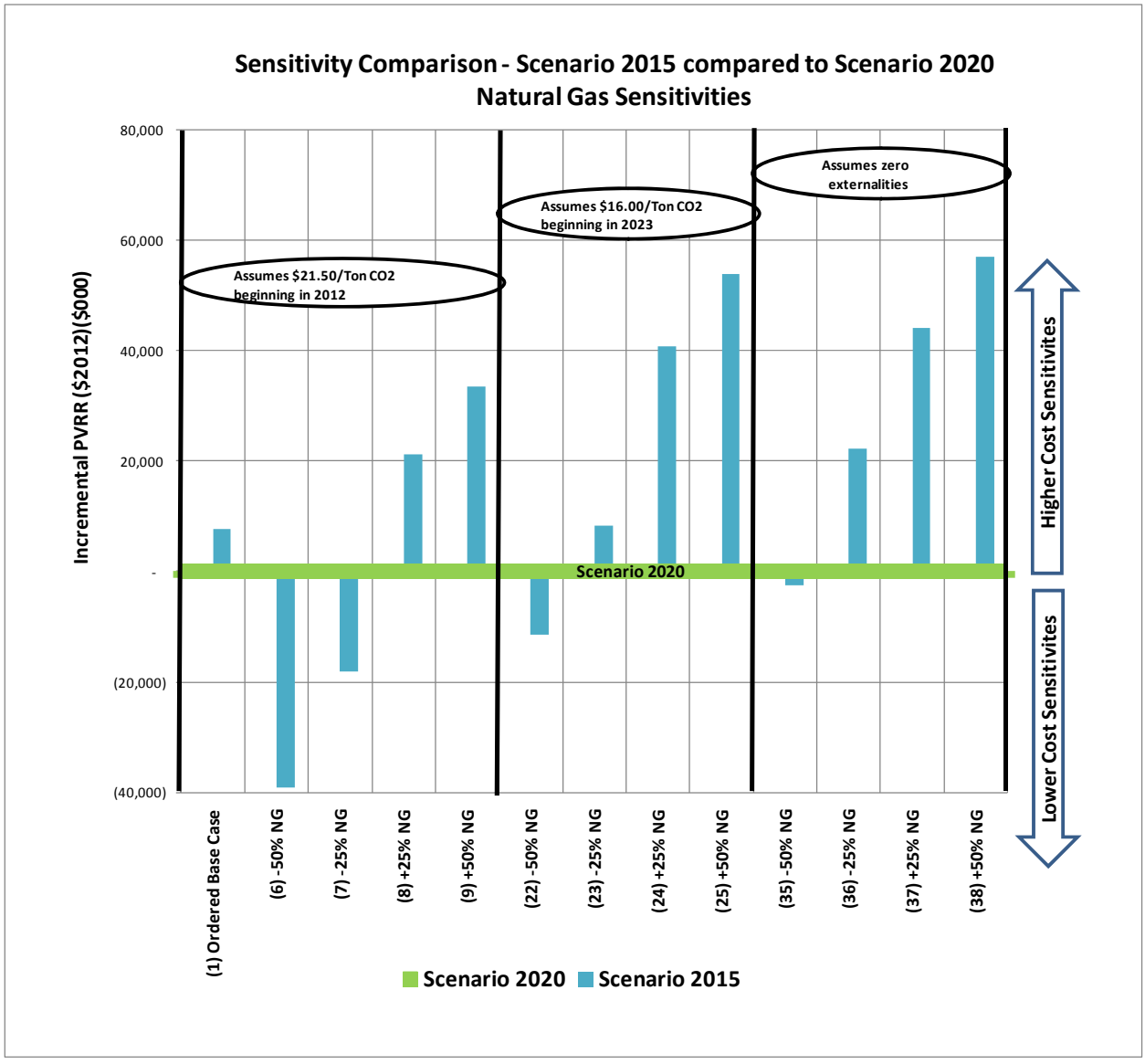


The following discussion breaks down the sensitivities into three categories—natural gas pricing, CO_2 cost, and other which includes electric market, wind, and coal price sensitivities as well as capital cost sensitivities.

1. Natural gas pricing sensitivity

The first breakdown to consider is the natural gas price sensitivities. The natural gas price forecast was taken from the May 2012 Wood-Mackenzie forecast. The sensitivities around this forecast are -50%, -25%, +25%, and +50%. This wide range is meant to cover the most extreme price forecast situations and also covers stakeholder opinions in this and other dockets. The breakdowns of the comparison between the *Scenario 2015 - Expedited Retirement* and *Scenario 2020 - Expected Retirement* with regard to natural gas pricing sensitivities can be seen in Figure 12 below.

Figure 12 - Breakdown of incremental PVRR for NG sensitivities

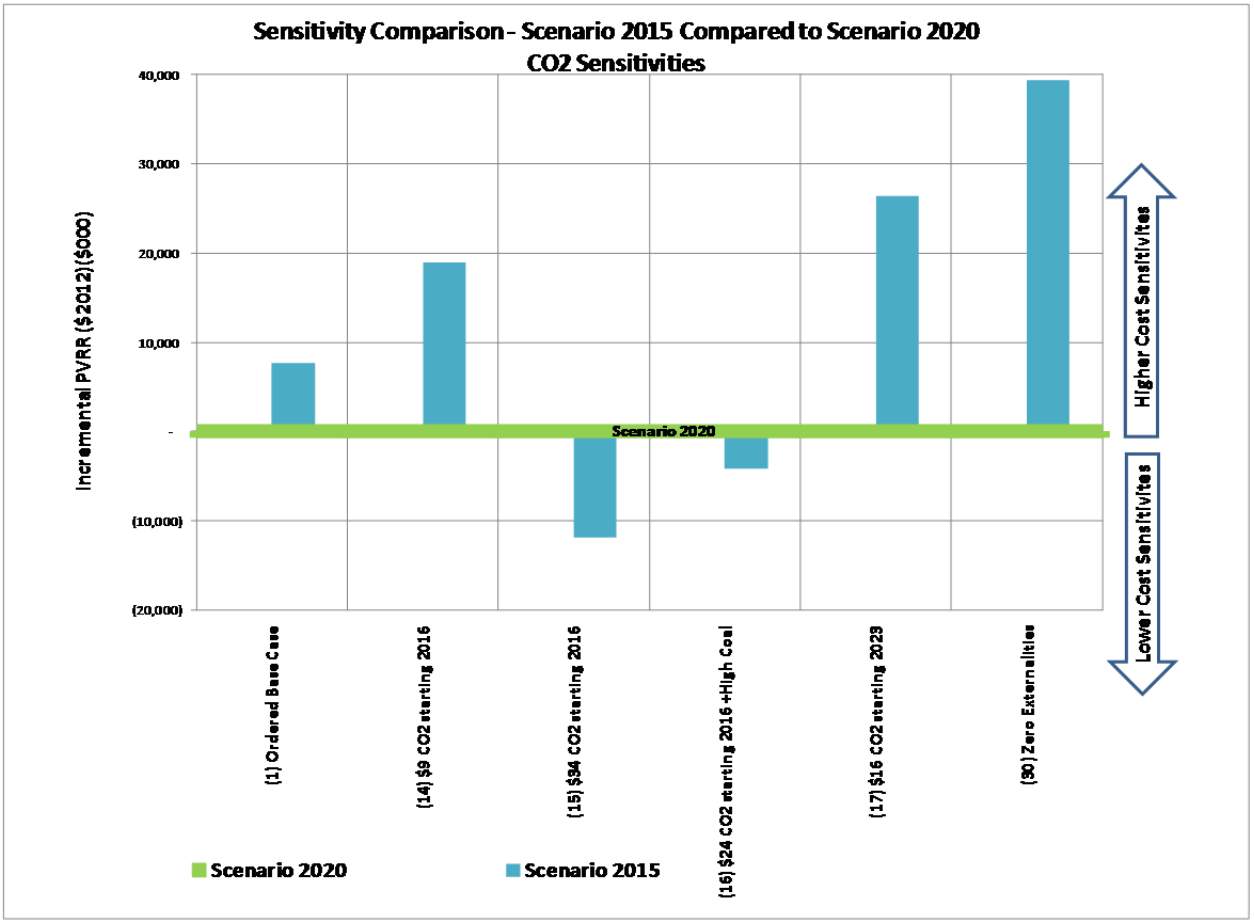


In only the extremely low natural gas price sensitivities is the expedited retirement cost-effective and this generally requires a significant level of CO_2 costs. The Strategist modeling runs between these two scenarios are not significantly different in regards to the size and type of natural gas generation additions. Both scenarios call for the addition of both peaking and combined cycle resources. The difference is in the timing and order of these additions and that results in the cost savings because there is a significant deferral of capital investment at a time when the other large capital investments are occurring.

2. CO_2 cost sensitivity

The second breakdown is the CO_2 cost sensitivities. In accordance with the MPUC order in this current docket, the base plan includes the cost of $21.50/ton of CO_2 beginning in 2012. A sensitivity analysis was also done looking at an array of other CO_2 cost assumptions. Figure 13 shows the graphical analysis.

Figure 13 - Breakdown of incremental PVRR of CO2 cost sensitivities



The base sensitivity in Figure 13 includes $21.50/ton CO_2 costs and indicates about $8 million lower PVRR for *Scenario 2020 - Expected Retirement*.

The Zero Externalities sensitivity applies \$0/ton of CO_2 (as well as \$0 for NOx and SO_2). Under these assumptions, *Scenario 2020 - Expected Retirement* is approximately \$40 million lower in PVRR than the *Scenario 2015 - Expedited Retirement.* During the stakeholder process, the North Dakota PSC staff, South Dakota PUC staff, the Minnesota Chamber of Commerce and the North Dakota Large Industrial Group requested that these sensitivities be studied.

The \$9 and \$34/ton CO_2 cost sensitivities are based on the range of externality costs established by the MPUC. The \$9 and \$34 cost assumptions were escalated at 3 percent a year (from 2012 to 2016) and then applied to CO_2 emissions in 2016 as requested by the Joint Interveners. In the sensitivity with \$9 CO_2 costs starting in 2016, *Scenario 2020 - Expected Retirement* is preferred by about \$20 million. In the case of \$34 CO_2 costs starting in 2016, *Scenario 2015 - Expedited Retirement* is preferred by just more than \$10 million.

The \$24 per ton of CO_2 costs starting in 2016 plus high coal (+20% starting in 2012) was a sensitivity specifically requested by the Joint Intervenors during the stakeholder process. Figure 13 shows that *Scenario 2015 - Expedited Retirement* is about \$4 million lower cost than *Scenario 2020 - Expected Retirement* for this combined sensitivity.

The \$16 CO_2 starting in 2023 sensitivity comes from the Wood Mackenzie forecast. This is the current cost level and starting date for CO_2 cost that is included in all Wood Mackenzie price forecasts. Figure 13 shows that *Scenario 2020 - Expected Retirement* is about \$26 million lower cost than *Scenario 2015 - Expedited Retirement* under this assumption.

3. Other sensitivities

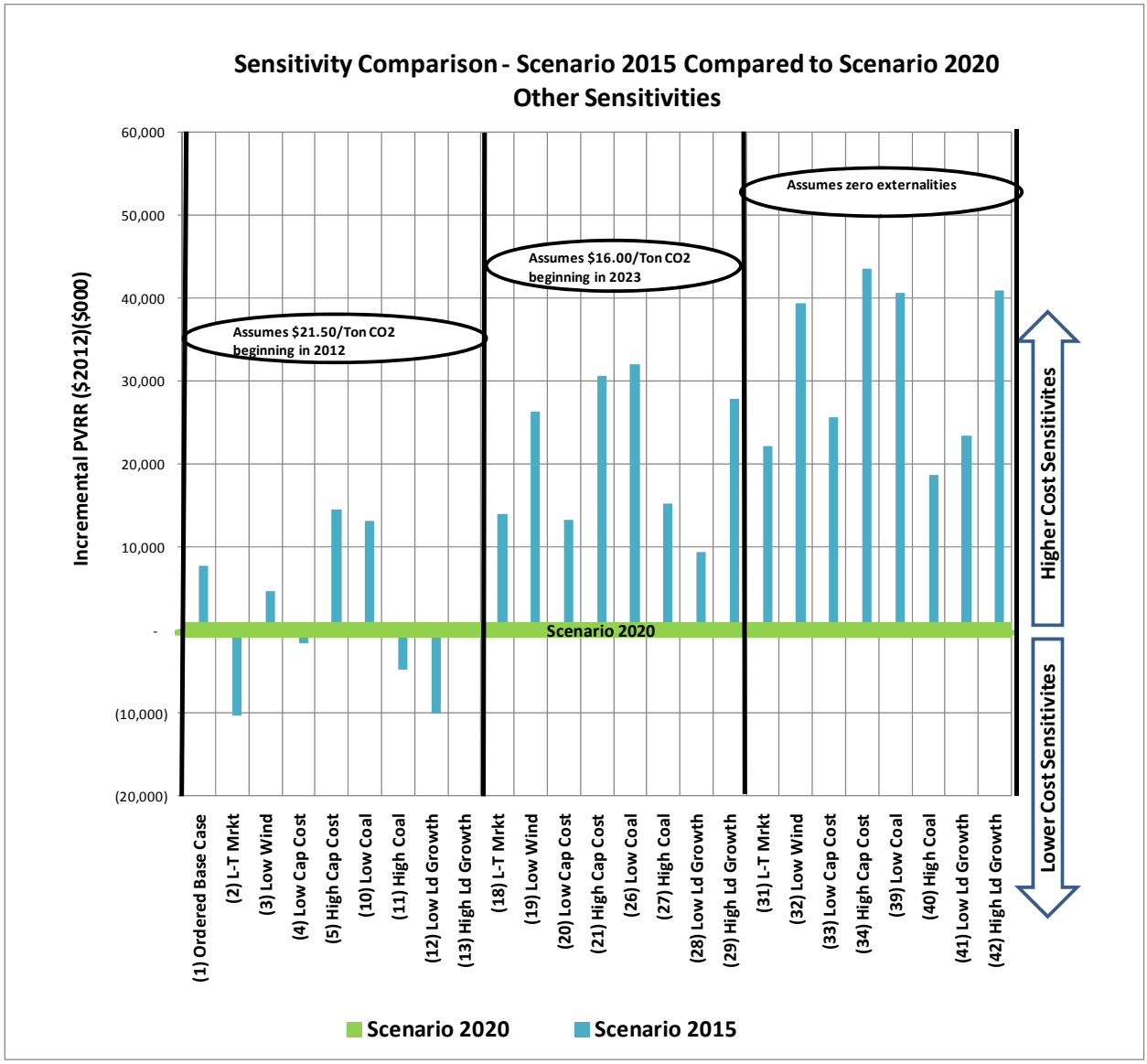
The remaining sensitivities are grouped in Figure 14. Generally, this set of sensitivities is less variable given the defined parameters.

The L-T Market sensitivity maintains the availability of market energy purchases in the Strategist model beyond 2017. The MPUC's current guideline to Otter Tail is to not rely on the energy market long-term. When this restriction is not in the model, *Scenario 2015 - Expedited Retirement* is preferred over *Scenario 2020 - Expected Retirement* by about \$10 million since it has a greater reliance on the spot-market for its energy.

The low wind sensitivity assumes lower wind energy cost (20%) than was assumed in the Strategist model. Under this sensitivity, *Scenario 2020 - Expected Retirement* is about \$5 million less expensive than *Scenario 2015 - Expedited Retirement.*

The capital cost sensitivities assume a +30% to -30% capital construction cost for all thermal generation projects. Figure 14 shows the low cap cost with \$21.50/ton CO_2 costs applied results in *Scenario 2015 - Expedited Retirement* scenario being slightly preferred to *Scenario 2020 - Expected Retirement*. In the high cap cost sensitivity, *Scenario 2020 - Expected Retirement* is preferred to *Scenario 2015 - Expedited Retirement* by about \$15 million.

Figure 14 - Breakdown of incremental PVRR of other sensitivities



The low/high coal sensitivities adjust the coal price to all Otter Tail Power Company coal-based generation by -10% and +20% (beginning in 2012). Figure 14 shows that in the low coal sensitivity with $21.50/ton CO_2 costs applied *Scenario 2020 - Expected Retirement* is preferred by about $13 million. Conversely, the high coal sensitivity results in a $5 million advantage to *Scenario 2015 - Expedited Retirement*.

The low and high load growth sensitivities are calculated through the load forecasting methodology. Significantly low load growth shows *Scenario 2015 - Expedited Retirement* to be lower by about $10 million with a $21.50/ton CO_2 cost applied. In the case of high load growth, the scenarios are nearly identical.

None of these sensitivities support the expedited retirement when the lower CO_2 assumptions are applied.

Otter Tail completed a robust set of Strategist modeling runs. The base case included assumptions as ordered by the MPUC in this current docket. The Company is confident that its modeling will closely mirror that of the DOC. In addition, sensitivities requested by stakeholders were also run. The Company is including the results of 126 Strategist runs, a vast majority of which show that Otter Tail's recommended plan around Hoot Lake Plant, *Scenario 2020 - Expected Retirement*, is the least cost for its customers.

The net result of numerous scenario and sensitivity analyses is that only a limited number of sensitivities support an expedited retirement for Hoot Lake Plant. Continuing with the planned retirement seems to have the most support among a diverse stakeholder group. While each of the two extremes (expedited retirement and long-term operation) is likely preferred among certain stakeholders, the modeling supports continuing towards the expected retirement date of 2020.

VI. BEYOND STRATEGIST CONSIDERATIONS

While the Strategist results discussed above are major considerations for this study analysis, other factors also merit consideration, including issues such as the timing of the capital expenditures and resulting rate increases for each scenario and the flexibility under each scenario to respond to changes in regulations, commodity markets, and other inputs. This section of the study discusses these additional considerations.

A. Assessing the rate increases that result from each of two scenarios

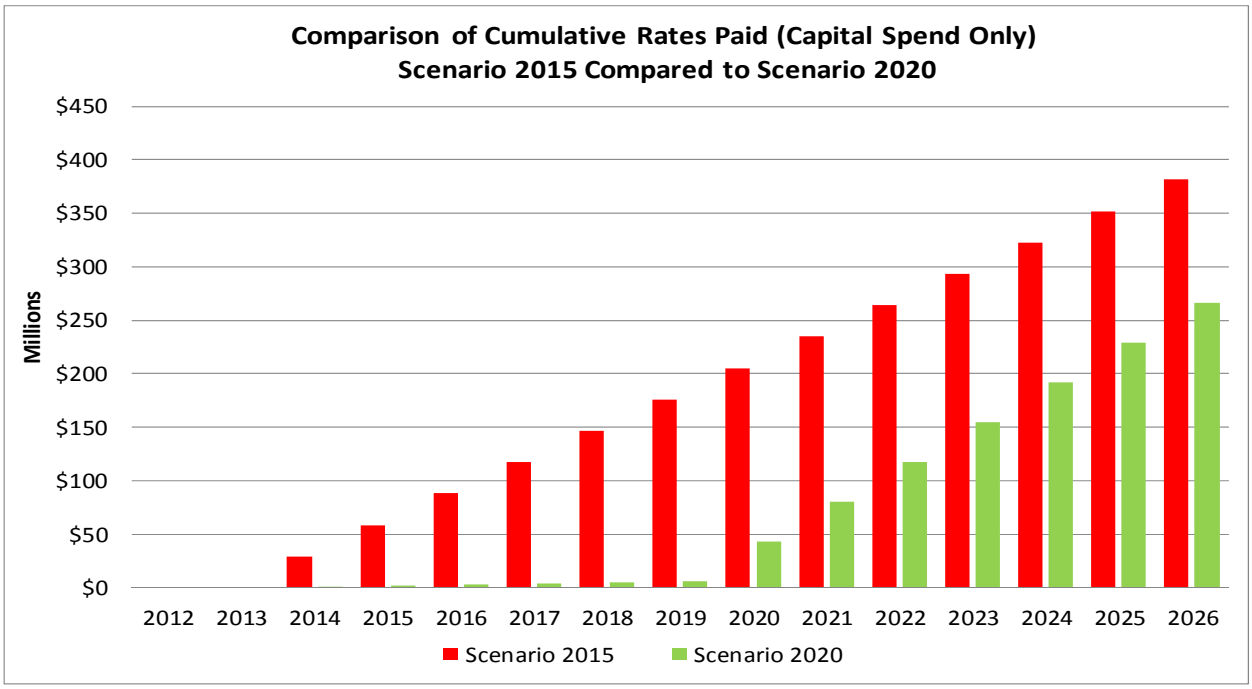
Hoot Lake Plant is a low cost resource for Otter Tail's customers. Its retirement and replacement will increase the rates Otter Tail's customers pay for electricity. The investment required to replace or retrofit Hoot Lake Plant with a gas generation unit(s) (a combination of simple and combined cycle resources as determined by Strategist) is expected to cost close to $280 million when completed under either scenario (2015 or 2020). Because Otter Tail's current rate base is approximately $625 million, these scenarios represent a 45 percent increase to total rate base at completion. Given this magnitude and no large reductions to expenses as this facility is replacing an existing depreciated facility, the rate increases are expected to be material – approximately 15 percent by the end of the project under either scenario. As has been explained above, *Scenario 2020 - Expected Retirement* would expect the capital costs to be incurred largely between 2017 and 2020. *Scenario 2015 - Expedited Retirement* moves the investment to five years earlier. This section of the study compares the economic impact of *Scenario 2015 - Expedited Retirement* and the *Scenario 2020 - Expected Retirement* for the purpose of assessing the economic benefit of deferring these capital costs by five years. Figure 15 compares the rate impacts under the two scenarios of capital spend.

For a residential customer, the difference in the scenarios is approximately $50 per year on average and for a large industrial customer could be as high as $725,000 per year on average for the period between 2015 and 2020. *Scenario 2020 - Expected Retirement* creates no additional rate impact over *Scenario 2015 - Expedited Retirement* ,but it delays the rate increases passed on to the customers. The impact is illustrated in Figure 16. To compare the scenarios, assume rates will be increased at the time of completion of the major components of capital spend – either through a general rate case or another rate mechanism. The area between the red and green lines is the difference. The rates are close to the same from 2020 on.

Figure 15 illustrates the impact further in terms of the cumulative rates paid under the 2015 and 2020 scenarios. The difference will not equalize until the end of the life of the project.

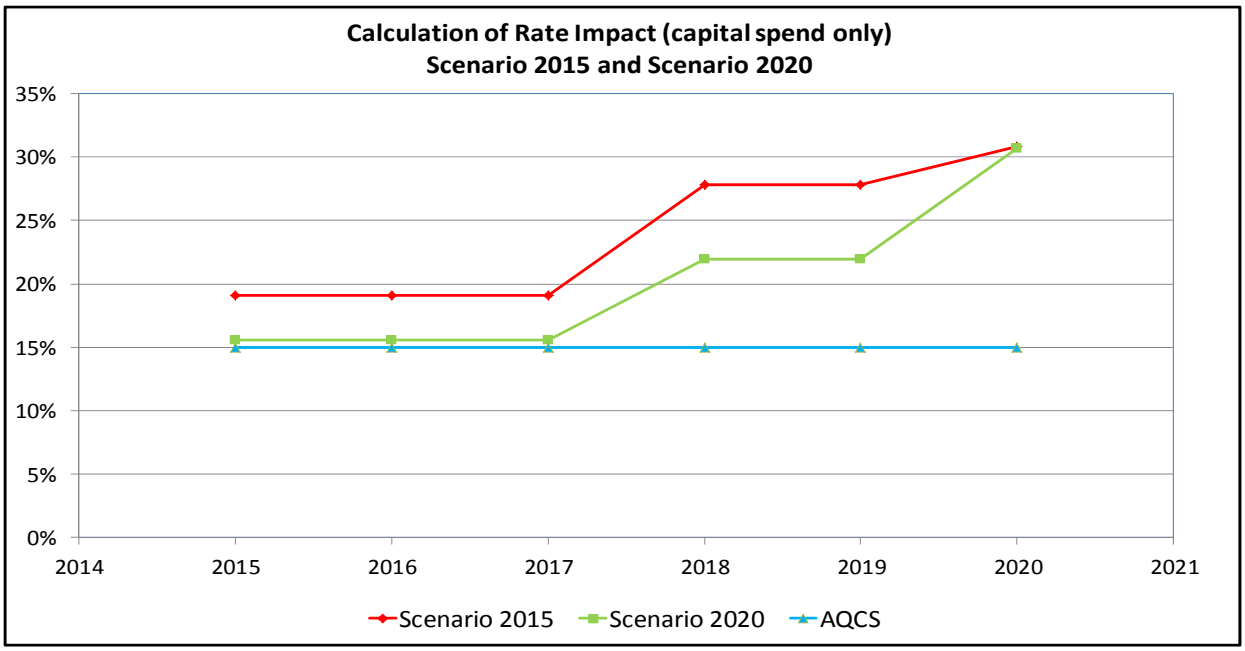
In addition to the general economic benefits of deferring capital project costs, deferral of this capital investment should have the additional benefit of preventing an unnecessary overlapping of two major projects' rate increases.

Figure 15 - Comparison of rates paid under different timing scenarios



	Cumulative $ through 2020	Cumulative $ through 2026
Retire 2015	$205,000,000	$382,000,000
Retire 2020	$44,000,000	$266,000,000
Difference	$161,000,000	$116,000,000

Figure 16 - Rate impact of capital project timing



As shown by Figure 16, *Scenario 2020 - Expected Retirement* delays major rate increases attributed to the action plan regarding Hoot Lake Plant. Otter Tail customers already are likely to have rate increases of about 14 percent to 15 percent by 2016 due to the AQCS project at Big Stone Plant. If Hoot Lake Plant replacement costs were "pancaked," that is, added to the AQCS costs in the same timeframe, customers could experience rate increases of 35 percent to 40 percent. Delaying Hoot Lake Plant replacement expenditures until 2020 would smooth rate increases for customers.

As shown by Figure 16, very little additional rate impact (less than one percent) occurs in 2020 in the *Scenario 2020 - Expected Retirement* (green line) as compared to *Scenario 2015 - Expedited Retirement*. As discussed earlier the beneficial impact on rates is in delaying the capital expenditures in the *Scenario 2020 - Expected Retirement*.

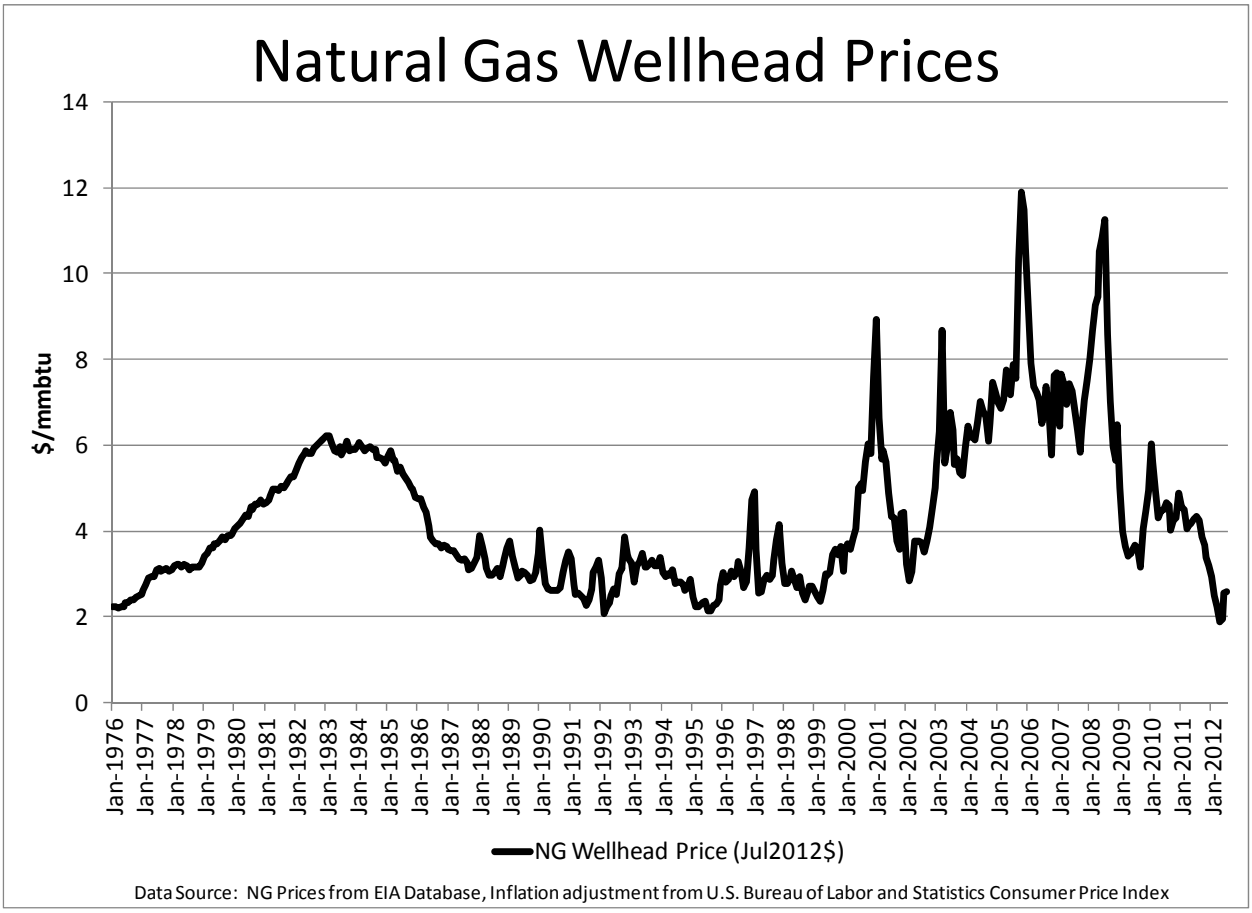
Additionally, the *Scenario 2020 - Expected Retirement* is a hedge against uncertainty (mainly gas prices and environmental regulation) with very little cost and with savings in rates for the period of 2015 to 2020.

B. Continued assessment before committing to expenditures

Another consideration is the variability and uncertainty of two key elements that could have a significant impact in the cost of the various plans under consideration: potential CO_2 regulation cost and natural gas prices.

Because the future of CO_2 cost is both a legislative and regulatory issue, the timing and magnitude of those costs are uncertain. Attempting to determine what costs or policies will apply and in what timeframe is highly speculative. One known is that natural gas prices have been volatile in the last five years. (See the 20-year natural gas price history included in Figure 17.)

Figure 17 - Natural gas pricing history



Many factors contribute to natural gas price uncertainty, including unconventional recovery methods, environmental concern about shale gas fracking, increase in demand due to low prices, and increase in power sector demand due to coal generation retirements. The significant uncertainty in these factors weighs in favor of a plan that delays the large capital expenditure of a natural gas generation resource for a few years while natural gas market volatility can be observed and the factors mentioned above either become more certain or the risk / benefit analysis weighs in favor of making the commitment. The customers will benefit for not having Otter Tail commit to such a large expenditure until it is required.

C. Socioeconomic considerations (jobs, taxes, etc.)

The primary socioeconomic value of *Scenario 2020 - Expected Retirement* is that it is the least-cost plan under a wide array of sensitivities to provide customers reliable and affordable energy and that is the focus of this study. Resource decisions can have other socioeconomic impacts and the potential retirement of Hoot Lake Plant is no exception. Hoot Lake Plant ranks #1 in tax base for the City of Fergus Falls. In a small community like Fergus Falls, and the sparsely populated surrounding region, such a disruption can be more consequential due to the relative magnitude of impact to the regional economy and the limited ability of those affected to weather the disruption (i.e. in a larger community with a larger and more diverse economy, the greater

scope and diversity of economic activity provides a greater resiliency to negative impact). Participants in the stakeholder process brought forward some examples of known impacts that Otter Tail believes should be noted as part of this study.

Specifically, Fergus Falls Mayor Hal Leland and Otter Tail Valley Railroad General Manager Rick Oeltjen attended the final stakeholder group meeting in St. Paul. Mr. Leland spoke of the importance of the jobs at Hoot Lake Plant and how payroll multiplies through the economy of the entire area. The property taxes of nearly $800,000 paid for Hoot Lake Plant are also a significant source of revenue for the city, school district, and county. Additionally, plant employees are active in local government, civic, and volunteer organizations. Mr. Oeltjen identified other large customers that Otter Tail Valley Railroad serves in the area and questioned whether the railroad could stay in business without coal deliveries to Hoot Lake Plant. If not, he stated that agricultural processors in the area would have to truck products to and from their plants, increasing their cost of doing business. Again, while these socioeconomic impacts do not by themselves control resource planning decisions, they are considerations that cannot be completely ignored.

D. MISO hourly based analysis

During the stakeholder process, Otter Tail was asked to analyze the concern of MISO LMP price variability, with a focus on high and low hourly price impacts as they relate to a baseload facility like Hoot Lake. Specific periods of low MISO real-time LMP prices have been observed in 2012, and the specific stakeholder request was for Otter Tail to include in this study an analysis of Otter Tail resources during periods of low LMP prices.

In summary, the analysis shows that Otter Tail is not typically affected negatively during periods of low LMP prices. The full analysis is in Appendix F.

E. Impact of EPA regulations on MISO coal plants

Current EPA regulations are causing a significant transition away from coal generation to natural gas generation. Otter Tail's *Scenario 2020 - Expected Retirement* avoids this "dash to gas" time period and allows the Company and its customers to move ahead cautiously along a safer path. Essentially, continuing with the expected retirement timeline instead of an expedited retirement mitigates the increased risk associated with a period when there is anticipated to be a significant disruption or transition in generation resources.

F. Other

Otter Tail is in a unique position as a multi-jurisdictional utility with approximately 50 percent of its customers in Minnesota and 50 percent in other jurisdictions. The Company believes selecting a plan that is acceptable in all of its jurisdictions is vital to continue planning and operating as a single integrated entity.

VII. RECOMMENDATION

As a result of the analysis described in this study, Otter Tail recommends *Scenario 2020 - Expected Retirement*, which includes a $10 million dollar expenditure on additional pollution control equipment and continued operation of Hoot Lake Plant as a coal facility until 2020. The study shows *Scenario 2040 - Long-term Coal Operation*, refurbishing Hoot Lake Plant to run as a coal plant beyond 2020, to cost more than the other alternatives. Although *Scenario 2020 - Expected Retirement* is least cost in the majority of sensitivities, the difference between it and the first scenario is less dramatic under certain sensitivities. Given the volatility of natural gas prices and the uncertainty of CO_2 legislation or regulation, customers should benefit from a plan that minimizes capital expenditures for constructing a new natural gas unit until decision makers have more natural gas price history and information about environmental regulations, particularly for CO_2. Likely even a bigger reason for recommending to continue with the expected 2020 retirement scenario is that *Scenario 2020 - Expected Retirement* minimizes costs to customers for Hoot Lake Plant at a time when they will see large rate increases due to required environmental upgrades already underway at Big Stone Plant.

Figures 18 and 19, compare Otter Tail's current resource mix and expected 2026 resource mix as modeled in the Strategist base case and assuming adoption of this recommendation.

Figure 18 - Strategist modeling results for 2012 capacity resources (ordered base sensitivity Scenario 2020 - Expected Retirement)

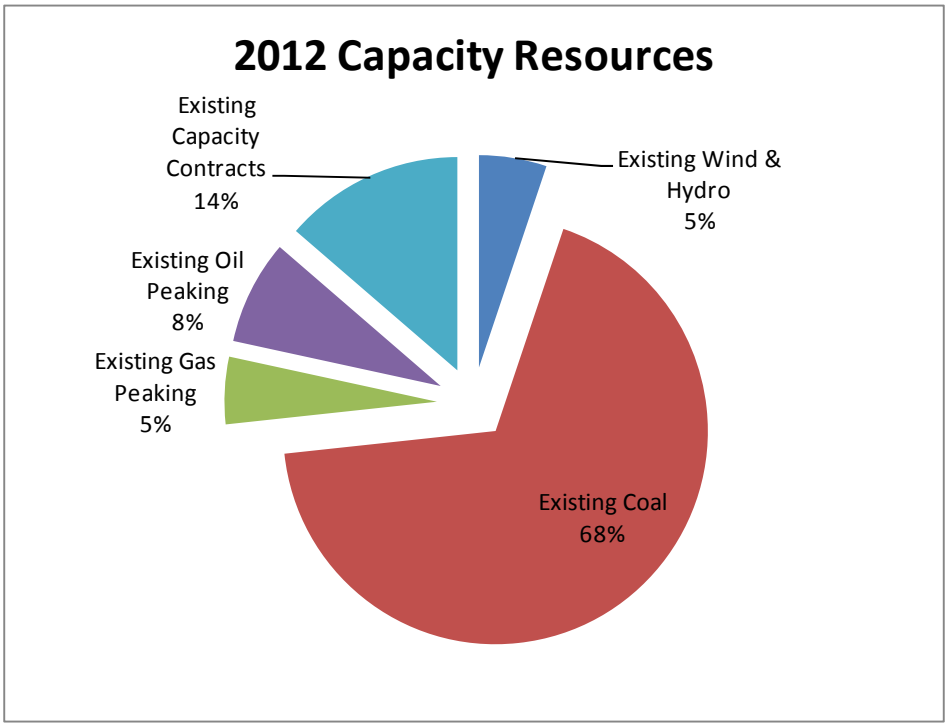
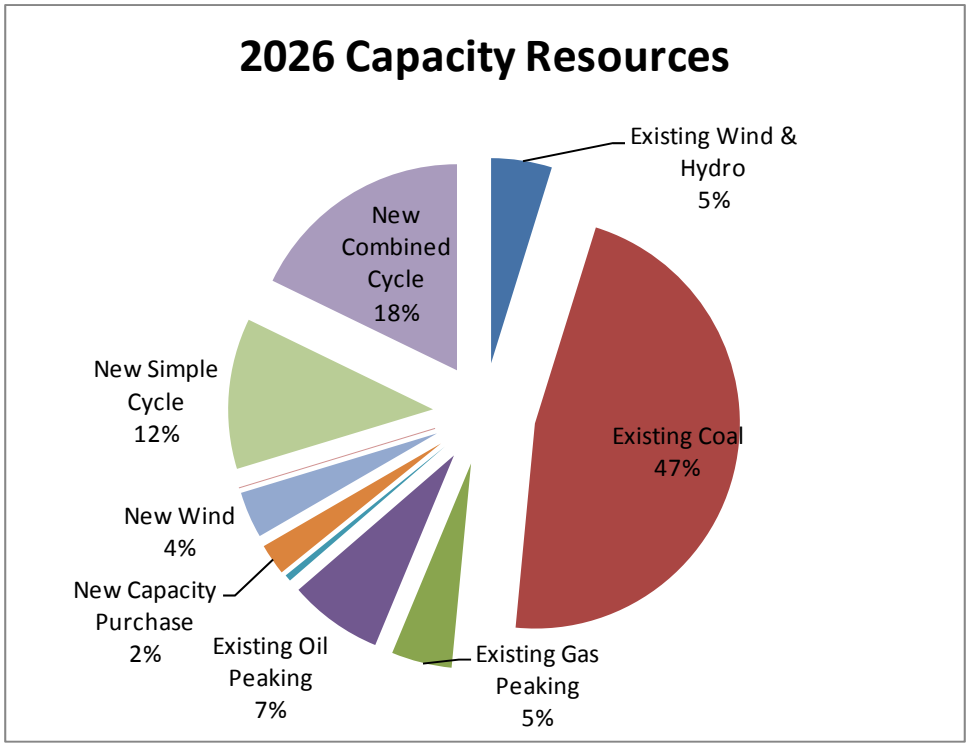


Figure 19 - Strategist modeling results for 2026 capacity resources (ordered base sensitivity Scenario 2020 - Expected Retirement)



The commitment to pursue the recommended option for Hoot Lake Plant requires the Company to commence procurement and planning for the $10 million baghouse replacement for the purpose of MATS compliance by 2015. This investment does not require any separate permitting or other regulatory proceedings.

Permitting is required for the replacement facilities expected to be constructed by 2020 in this recommended plan. Given the expected lead times for permitting, procurement and construction, the Company should commence permitting by 2015. Obviously, the specific nature and timing for the replacement resources will be extensively evaluated in those proceedings. It will also continue to be evaluated in Otter Tail's subsequent IRP proceedings (2013, 2015, etc.). In each of these proceedings, the specific nature and timing of the retirement/replacement will be evaluated based upon what is known at that time with respect to natural gas price forecasts, energy price forecasts, anticipated costs of compliance with environmental regulations, operational performance of the facility, and the specific costs for replacement resources and other relevant factors.

VIII. CONCLUSION

The purpose of this Baseload Diversification Study has been to evaluate the retirement and repower options for Hoot Lake Plant. It is a continuation of Otter Tail's IRP Docket No. E017/RP-10-623, which was approved as modified on February 9, 2012. In this study, Otter Tail did not re-address the issues that were decided in the IRP order.

Hoot Lake Plant currently serves as a reliable, low-cost generation source that meets about one fifth of Otter Tail's capacity and energy requirements. This study has evaluated the retirement and repowering options for the Hoot Lake Plant. Results indicate that a reasonable plan for Otter Tail is to pursue *Scenario 2020 - Expected Retirement* described above. This plan is economic for Otter Tail's customers as reflected in the Strategist modeling results. It also provides the additional benefits of avoiding the "overlapping" of a natural gas resource replacement expenditure and the expenditures for the Big Stone AQCS project. This plan also provides greater flexibility to monitor natural gas pricing and legislative and regulatory changes that may take place over the next several years than does *Scenario 2015 - Expedited Retirement.*

While this study is called a baseload "diversification" study, it may be more realistically a baseload "transition" study since both *Scenario 2015 - Expedited Retirement* and *Scenario 2020 - Expected Retirement* ultimately arrive at the same replacement for Hoot Lake Plant. It is only the timing of the retirement and additions that is different.

To meet the MATS compliance timeline, Otter Tail requests MPUC approval of this study in an expeditious manner so installation of environmental upgrades can be completed in a timely manner. The Company assumes that the MPUC's decision on this study carries the weight of a resource plan decision given that this is a deferred decision continued under the Company's most recent resource plan docket.

Appendix A

Assessment of Federal and State Environment Regulations

Appendix A - Assessment of Federal and State Environmental Regulations

I. CRITERIA AIR POLLUTANTS

The Clean Air Act ("CAA") requires EPA to set standards for six common air pollutants known as "criteria" pollutants. The criteria pollutants are: nitrogen oxides ("NO_X"), sulfur dioxide ("SO_2"), particulate matter ("PM"), ozone, carbon monoxide and lead. These emissions are sometimes regulated under CAA programs when they are a precursor to other types of air pollution. NO_X, for example, is regulated because it is a precursor to fine particle formation, ozone formation, acid deposition and regional haze. Similarly, SO_2 is a precursor to fine particle formation, acid deposition and regional haze. Particulate matter is a precursor to regional haze. This section describes the effect of anticipated regulations to limit criteria pollutant emissions from power plants, with a specific focus on Hoot Lake Plant.

A. Acid Deposition

The Acid Rain Program ("ARP") was created under Title IV of the 1990 amendments to the CAA. Under the ARP, emissions of SO_2 and NO_X from the electric utility industry have been reduced substantially.

1. ARP SO2 Program

The SO_2 program sets a permanent cap on the total amount of SO_2 that may be emitted by electric generating units greater than 25 megawatts in the contiguous United States. The program was phased in, with the final 2010 SO_2 cap set at 8.95 million tons, which represents a level of about one-half of the emissions from the power sector in 1980.

Under this program, EPA allocates allowances to each source for use in or after a specified year. Each allowance permits a unit to emit 1 ton of SO_2. At the end of the year, if a source's emissions are less than its annual allowance allocation, it can bank the extra allowances forward for use in future years. If a source's annual emissions are more than its annual allocation, the source can then either use banked allowances from previous years, transfer allowances from another facility, or purchase allowances on the open market.

Otter Tail's compliance strategy has always been, and continues to be, to work within our free allowance allocation and use banked allowances when necessary to avoid having to purchase allowances on the open market. Otter Tail has not sold any of our banked allowances, which we believe positions ourselves to avoid having to purchase allowances in the future for Hoot Lake Plant.

2. ARP NOx Program

Title IV requires NO_x emission reductions for certain coal-fired EGUs by limiting the NO_x emission rate (expressed in lb/mmBtu) in lieu of having an emissions allowance trading program. Congress applied these rate-based emission limits based on a unit's boiler type. The goal of the program is to limit NO_x emission levels from the affected coal-fired boilers so that their emissions are at least two million tons less than the projected level for the year 2000 without implementation of Title IV. Otter Tail has maintained compliance with the Title IV NO_x emission rates by installing low NO_x burners on both Hoot Lake Plant Units 2 and Unit 3.

B. National Ambient Air Quality Standards

The CAA requires EPA to set two types of National Ambient Air Quality Standards ("NAAQS"). Primary standards provide public health protection, while secondary standards provide public welfare protection.

In general, compliance with NAAQS is achieved through development of State Implementation Plans ("SIPs") that limit emissions from sources located in areas designated as non-attainment.

To help states attain the NAAQS in local areas, the EPA evaluates whether certain regional or nationally applicable emission limitations should be put into place in order to assist the states in attaining the NAAQS, or states may petition EPA to impose reductions in upwind states. Additionally, federal regulations require that any permit issued under the Prevention of Significant Deterioration ("PSD") provisions of the CAA must contain a demonstration of source compliance with the NAAQS.

1. SO2 and NO2 NAAQS

In 2010, the EPA promulgated new NAAQS for nitrogen dioxide ("NO_2") and SO_2 averaged over one hour.

For the 2010 NO_2 NAAQS, the State of Minnesota recommended that the entire state be designated as attainment based on three years (2007 – 2009) of air sampling data. The EPA reviewed the recommendation, and on January 20, 2012 EPA designated Minnesota, along with all areas of the country, as "unclassifiable/attainment". EPA and the states are now in the process of expanding the NO_2 monitoring network, and EPA plans to re-designate areas in 2016 or 2017 based on the new monitoring data, resulting in attainment deadlines in 2021-2022.

For SO_2, Minnesota has no monitored violations of the 2010 NAAQS, and will need to submit a "infrastructure" SIP by June 2013 to demonstrate that they have appropriate authorities to ensure that the State will maintain compliance with the standard. EPA originally issued draft guidance that required states to conduct air dispersion modeling in order to demonstrate attainment with the 2010 SO_2 NAAQS by July of 2017; however, in April 2012 EPA announced that they will not be requiring the infrastructure SIP submittal to contain modeling demonstrations. EPA

subsequently held stakeholder meetings and requested public comment to further discuss how to implement the SO_2 standard. Concurrent with the April 2012 EPA announcement, the MPCA informed Otter Tail that the MPCA will be working to determine how best to move forward and waiting for updated EPA guidance.

2. Ozone and PM NAAQS

In the electric power industry, recent attempts to assist with attainment of the NAAQS for ozone and particulate matter from regional sources have been made through EPA's Clean Air Interstate Rule ("CAIR") and Cross-State Air Pollution Rule ("CSAPR").

a. Clean Air Interstate Rule

On March 10, 2005, the EPA Administrator signed the Clean Air Interstate Rule ("CAIR") to address areas in the eastern half of the United States that were in non-attainment with the 1997 ozone and fine particulate matter NAAQS. The rule required SO2 and NOx emissions reductions in 28 states and the District of Columbia, including Minnesota, which was included because the state was deemed to contribute to downwind violations for fine particulate matter.

CAIR created a cap-and-trade program for SO_2 and NO_x allowances similar to the ARP SO_2 program, and in fact, Title IV SO_2 allowances are used for compliance with CAIR. The first phase of CAIR NO_x reductions began in 2009, and the first phase of CAIR SO_2 reductions began in 2010. In anticipation of CAIR, NO_x emissions control equipment was installed on Hoot Lake Plant Unit 2 in 2008, and on Unit 3 in 2006.

A number of petitioners brought legal challenges to various aspects of CAIR in the U.S. Court of Appeals for the D.C. Circuit. Among the challenges was that EPA erred in including the State of Minnesota. On July 11, 2008, after hearing the challenges, the Court vacated CAIR and agreed that EPA had failed to address alleged errors in its analysis for the State of Minnesota.

EPA filed a petition for rehearing on a number of the Court's findings, but did not seek rehearing of the findings regarding Minnesota. On December 23, 2008, the Court granted EPA's petition for rehearing only to the extent it remanded the case without vacatur. This decision allowed CAIR to remain in effect until EPA develops a permanent replacement rule. On May 12, 2009, EPA issued a proposed rule staying the effectiveness of CAIR for Minnesota sources while it conducts notice-and-comment rulemaking addressing whether Minnesota should be included in the CAIR region. Public notice of the final rule staying the implementation of CAIR in Minnesota appeared in the November 3, 2009 *Federal Register*. Therefore, Otter Tail has not managed any emissions allowances or had to comply with CAIR.

b. Cross-State Air Pollution Rule

On July 6, 2010, the EPA proposed a rule, termed the Transport Rule, that would require annual SO_2 and NO_x reductions in 23 states, including Minnesota. EPA attempted to design the rule to address the concerns of the Court with respect to CAIR.

As proposed, the rule required that Otter Tail manage a new set of SO_2 and NO_x allowances separate from the Title IV ARP allowances beginning with calendar year 2012. However, the Transport Rule's impact on Hoot Lake Plant would have been minimal and not required any emissions reductions or allowance purchases to be made. The EPA released the final Transport Rule, renamed as the Cross-State Air Pollution Rule ("CSAPR"), on July 8, 2011. The final rule made several changes as compared to the proposed rule, including a substantial change in the allowance allocation methodology, whereby Hoot Lake Plant would need to purchase SO_2 allowances to continue operating at historical levels[1].

A number of states and industry representatives challenged CSAPR, and on December 30, 2011, the D.C. Circuit granted motions to stay CSAPR pending the Court's resolution of the petitions for review. The Court subsequently heard oral argument on April 13, 2012, and issued an order on August 21, 2012 to vacate CSAPR. The order requires EPA to continue administering the Clean Air Interstate Rule pending the promulgation of a valid replacement rule. Due to the immense uncertainty of CSAPR during the time period of this Baseload Diversification Study, Otter Tail took a conservative approach and assumed that CSAPR will take effect in 2013. At this time it is difficult to determine what compliance measures will need to be taken for a future rule, although Otter Tail believes that a replacement rule will be promulgated prior to 2020.

C. Regional Haze Program

EPA promulgated the Regional Haze Rule ("RHR") in 1999 to address visibility impairment in Class I areas. Class I areas include 156 national parks and wilderness areas, including the Boundary Waters Canoe Area Wilderness and Voyager's National Park in Minnesota. States were required to submit SIPs detailing their strategy to reduce haze, and to set reasonable progress goals that meet the goal of no man-made visibility impairment in Class I areas by 2064. The first regional progress goals must be established for the planning period 2008 to 2018.

Included in the RHR is a provision that sources built between August 7, 1962 and August 7, 1977, and that are found to contribute to visibility impairment in Class I areas, must install best available retrofit technology ("BART"). Hoot Lake Plant Unit 3 was built within the 1962 – 1977 timeframe, and therefore was required to be evaluated whether or not it contributes to visibility impairment in Class I areas.

In March 2006 the MPCA conducted source-specific dispersion modeling of all BART-eligible Minnesota sources to determine if they contribute to Class I area visibility impairment. The MPCA's dispersion modeling determined that Hoot Lake Plant Unit 3 did not significantly contribute to visibility impairment, and is thus not subject to BART. The MPCA submitted a Regional Haze SIP to EPA for approval on December 30, 2009, which included the findings on

[1]As detailed in Otter Tail's initial filing for Docket No. E017/M-12-179

Hoot Lake Plant. EPA published final approval of the Minnesota SIP on June 12, 2012[2]; therefore, at this time Hoot Lake Unit 3 does not need to take any further action.

Going forward, states are required by 40 CFR 51.308(g) to submit five-year periodic reports evaluating progress towards the goals established for each mandatory Class I area. Based on the findings of the five-year periodic progress report, a state must make a determination of adequacy of the existing SIP and take action if the strategies are found to be inadequate. In addition, states are required by 40 CFR 51.308(f) to revise their regional haze implementation plan and submit a plan revision to EPA by July 31, 2018, and every 10 years thereafter. The revised plan must address current visibility conditions, effectiveness of the long-term strategy, and affirm or revise reasonable progress goals for Class I areas.

At this time it is highly uncertain how future regional haze SIP revisions could affect Hoot Lake Plant, but Otter Tail believes it could likely require NOx, SO_2, and particulate matter reductions in the post-2020 timeframe.

II. HAZARDOUS AIR POLLUTANTS

A. Mercury and Other Hazardous Air Pollutant Emissions Rulemaking

The 1990 Amendments to the CAA required EPA to study the effects of emissions of listed hazardous air pollutants by electric steam generating plants. The EPA completed required studies and submitted reports to Congress, and determined that it would regulate mercury emissions from electric generating units under the hazardous air pollutant requirements of the CAA.[3] EPA then published final rules that reversed this determination and set forth a cap and trade program for mercury emissions; however, EPA's cap and trade mercury rule was reversed by the United States Court of Appeals for the D.C. Circuit in February 2008.

In response to the D.C. Circuit Court's vacatur, on March 16, 2011, EPA proposed Section 112 air toxics standards for all coal- and oil-fired EGUs that reflect the application of the maximum achievable control technology (MACT) consistent with the requirements of the CAA. EPA signed a final rulemaking, termed the mercury and air toxics standards (MATS) rule, on December 16, 2011, which was subsequently published in the Federal Register on February 16, 2012.

Power plants will have three years and sixty days from the date of publication (April 16, 2015) to comply with MATS, although EPA is encouraging state permitting authorities to broadly grant a

[2] Note that EPA deferred action on the MN Regional Haze SIP for taconite facilities and Xcel Energy's Sherburne County facility until a later time

[3] 65 Fed. Reg. 79825 (Dec. 20, 2000), Regulatory Finding on the Emissions of Hazardous Air Pollutants fromElectric Utility Steam Generating Units.

one-year compliance extension to plants that need additional time to install controls. The EPA is also providing a pathway for reliability critical units to obtain an additional year to achieve compliance; however, the EPA believes there will be few, if any situations, in which this pathway is needed. Based on Otter Tail's review of the final rule, Hoot Lake Plant would meet MATS by adding a fabric filter on Unit 3, installing mercury control technology such as activated carbon injection on Units 2 and 3, and possibly installing a sodium or calcium based dry sorbent injection system to control hydrogen chloride. Emissions monitoring equipment and/or stack testing will also be needed to verify compliance with the standards.

B. Minnesota TMDL

The federal Clean Water Act requires each state to evaluate its water bodies and determine whether they meet water-quality standards. For mercury, these standards define how much mercury can be in the water and in fish. Water bodies that do not meet water-quality standards are added to a list of water bodies referred to as the Impaired Waters List. About two-thirds of the water impairments on Minnesota's 2006 Impaired Water List were due to mercury.

To address impaired waters, states are required to evaluate the sources of pollution, the reduction in the pollutant needed to meet water-quality standards, and allowable levels of future pollution. This evaluation, typically done for each water body or watershed, is called a Total Maximum Daily Load, or TMDL. Because the source of essentially all mercury to Minnesota waters is the atmosphere, the Minnesota Pollution Control Agency (MPCA) prepared a statewide mercury TMDL. This TMDL established an annual mercury air emission target of 789 pounds, and was approved by the MPCA Board in December 2006 and by the EPA in March 2007.

To achieve the goals of the TMDL, a stakeholder process was convened to develop specific recommendations. The stakeholders identified sector-specific strategies to meet the TMDL targets by 2025, and one of the sector-specific strategies includes reducing mercury emissions from Minnesota coal-fired generation.

According to the final TMDL stakeholder strategy document, Hoot Lake Plants Units 2 and 3 will be required to file with the MPCA by 2015 a mercury emissions reduction plan that is most likely to result in the removal of at least 70 percent of the mercury emitted from each unit or an equivalent reduction by 2025. Since this timeframe is beyond the timeframe of compliance for the MATS rule, compliance with the TMDL target for Hoot Lake Plant will be demonstrated through compliance with the MATS rule.

III. GREENHOUSE GAS REGULATION

A. Background

In April 2007, the U.S. Supreme Court issued a decision that determined that the EPA has authority to regulate carbon dioxide ("CO_2") and other greenhouse gases ("GHGs") as air pollutants under the CAA. The Supreme Court remanded the case to the EPA to conduct a rulemaking to decide whether GHGs may reasonably be anticipated to endanger public health or welfare, and if so, whether GHGs cause or contribute to climate change. While this case addressed a provision of the CAA related to emissions for motor vehicles, other provisions of the CAA apply to stationary sources such as electric generating units.

The first step in the EPA rulemaking process was the publication of an endangerment finding in the Federal Register on December 15, 2009. The EPA found that CO_2 and five other GHGs – methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride – threatened public health and welfare. These findings did not themselves impose any requirements to control GHG emissions, but they were a prerequisite to finalizing GHG standards for vehicles under title II of the Act. EPA then adopted GHG standards for new light duty vehicles as part of a joint rulemaking with the Department of Transportation. These standards apply to motor vehicles as of January 2011, which makes GHGs "subject to regulation" under the CAA. Although applicable only to motor vehicles, the standard regulates GHG emissions for the first time under the CAA, and GHG emissions are therefore included in the pollutants subject to the requirements of the New Source Review program of the CAA.

B. New Source Review

Under the New Source Review Program, the Prevention of Significant Deterioration ("PSD") program applies to areas of the country that attain the NAAQS (or are unclassifiable), such as the area in which the Hoot lake Plant is located. PSD review requires persons constructing new major air pollution sources or implementing significant modifications to existing air pollution sources that constitute a significant net emissions increase to obtain a permit prior to such construction or modification. In order to obtain a PSD permit, the owner or operator of an affected facility must undergo a review which requires the identification and implementation of best-available control technology ("BACT") for the regulated air pollutants for which there is a significant net emissions increase, and an analysis of the ambient air quality impacts of the facility.

On June 3, 2010, EPA issued a final "tailoring rule" that phases in application of this program to GHG emission sources, including power plants. This program applies to existing sources such as Hoot Lake if there is a physical change or change in the method of operation of the facility that results in a significant net emissions increase. As a result, PSD does not apply on a set

timeline as is the case with other regulatory programs, but is triggered depending on what activities take place at a major source.

The EPA decided to phase in the PSD requirements for GHGs in two steps. Beginning on January 2, 2011, GHG control analysis was conducted in PSD permit proceedings only if changes at a facility trigger PSD for criteria pollutants and if the proposed change increases GHGs by over 75,000 tons per year of CO_2e, a measure that converts emissions of each GHG into its carbon dioxide equivalent. Until July of 2011, the threshold applied only to facilities currently subject to PSD or Title V permitting. However, as of July 2011, sources emitting more than 100,000 tons per year of CO_2e are considered major sources subject to PSD requirements if they propose to make modifications resulting in a net GHG emissions increase of 75,000 tons per year or more of CO_2e. Hoot Lake Plant is not contemplating any changes that would result in a significant net GHG emissions increase.

C. New Source Performance Standards

On March 27, 2012, EPA announced proposed New Source Performance Standards ("NSPS") that would additionally regulate GHGs from new electric generating units. The proposed rulemaking would require certain new plants, including coal-fired boilers and combined cycle gas turbines, to achieve a CO_2 emission rate of 1,000 pounds per megawatt-hour gross. The rulemaking would not apply to new simple cycle turbines or existing plants of any kind, including reconstruction or modification of existing plants.

D. Greenhouse Gas Regulation Outside the Clean Air Act

Debate continues in Congress on the direction and scope of U.S. policy on climate change and regulation of GHGs. Although several bills have been introduced in Congress that would compel reductions of CO_2 emissions (for example the U.S. House of Representatives on June 26, 2009 passed the American Clean Energy and Security Act of 2009, also known as "Waxman-Markey"), no legislation establishing a comprehensive approach to mandatory GHG reductions has passed Congress. It appears doubtful to Otter Tail that any federal cap and trade reduction program will be adopted by Congress in the near future.

IV. COAL COMBUSTION RESIDUALS REGULATION

On June 21, 2010, EPA published a proposed rule that outlines two possible options to regulate disposal of coal ash generated from the combustion of coal by electric utilities under the Resource Conservation and Recovery Act ("RCRA"). In one option, EPA would propose to list coal ash destined for disposal in landfills or surface impoundments as "special wastes" subject to regulation under Subtitle C of RCRA. Subtitle C regulations set forth the EPA's hazardous waste regulatory program, which regulates the generation, handling, transport and disposal of wastes.

The proposal would create a new category of special waste under Subtitle C, so that coal ash would not be classified as hazardous waste, but would be subject to many of the regulatory requirements applicable to hazardous wastes. This option would subject coal ash to technical and permitting requirements from the point of generation to final disposal. EPA is considering whether to impose disposal facility requirements such as liners, groundwater monitoring, fugitive dust controls, financial assurance, corrective action, closure of units, and post-closure care. This option also includes potential requirements for dam safety and stability for surface impoundments, land disposal restrictions, treatment standards for coal ash, and a prohibition on the disposal of treated coal ash below the natural water table. Beneficial re-uses of coal ash would not be subject to these requirements.

Under the second proposed regulatory option EPA would regulate the disposal of coal ash under Subtitle D of RCRA, the regulatory program for non-hazardous solid wastes. In this option, EPA is considering issuing national minimum criteria to ensure the safe disposal of coal ash, which would subject disposal units to location standards, composite liner requirements, groundwater monitoring and corrective action standards for releases, closure and post-closure care requirements, and requirements to address the stability of surface impoundments. Within this option, EPA is also considering not requiring existing surface impoundments to close or install composite liners and allowing them to continue to operate for their useful life.

This option would not regulate the generation, storage, or treatment of coal ash prior to disposal, and no federal permits would be required.[4] EPA's proposal also states that EPA is considering whether to list coal ash as a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), and includes proposals for alternative methods to adjust the statutory reportable quantity for coal ash. EPA has not decided which regulatory approach it will take with respect to the management and disposal of coal ash.

The Hoot Lake Plant operates a dry ash disposal site that is regulated, permitted and inspected by the MPCA. The ash is transported to the site with conventional earthmoving equipment. The existing operating site is lined with a synthetic liner and it has a leachate collection system. Future portions of the designated disposal areas will be covered with a synthetic cover and an engineered soil cover. The site has a groundwater monitoring system and annual reports have been provided to the MPCA. While additional requirements may be imposed as part of EPA's pending rule, identification of specific costs would be contingent on the requirements of the final rule.

The most costly option in the EPA proposal is the option that would regulate all coal ash destined for disposal as special waste. If EPA imposes this option, OTP projects a disposal cost

[4] 75 Fed. Reg. 35133 (June 21, 2010), Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities, Proposed Rule.

of $37.50 per ton in 2010 dollars.[5] This would translate into a yearly cost of approximately $826,000 per year based on the amount of CCR produced in 2011 (22,026 tons). If EPA chooses another regulatory option, it would impose less cost than this estimate. It is also possible that the new regulations would not require change in the current operation and cost of OTP's coal ash disposal site. However, since the Hoot lake Plant CCR disposal site already includes many of the site design features under consideration by EPA, OTP is not expecting a significant increase in the capital cost of the CCR disposal site although operation and maintenance costs could increase due to more stringent administrative requirements.

V. WATER REGULATION

A. 316(b)

Section 316(b) of the Clean Water Act ("CWA") requires facilities with cooling water intake structures to ensure that the location, design, construction and capacity of the structures reflect the best technology available to minimize harmful impacts on the environment. EPA first promulgated regulations to implement section 316(b) in 1976. In 1977 the U.S. Court of Appeals for the Fourth Circuit remanded these regulations to EPA, which withdrew them and left in place a provision that directed permitting authorities to determine best technology available for each facility on a case-by-case basis.

Hoot Lake Plant uses once-through cooling except during periods of low water availability and during periods when the water discharge permit require use of the plant cooling towers. The impact of the Hoot Lake Plant intake structure has been extensively evaluated in two separate studies (conducted in 1976 and 2005), both of which showed minimal impact, and in fact in December 1977 the MPCA, the Minnesota Department of Natural Resources, and EPA concluded that Hoot Lake Plant's intake structure creates a negligible impact in the aquatic ecosystem and was therefore in compliance with Section 316(b).

After numerous years of proceedings, on April 20, 2011, EPA published proposed national standards for cooling water intake structures at all existing power generating facilities and existing manufacturing and industrial facilities as part of further implementing Section 316(b).

After issuing the proposed rule, EPA received extensive comments and new data, including the two Hoot Lake Plant studies. Due to the new information EPA received, they published a Notice of Data Availability ("NODA) on June 11, 2012 to provide a further opportunity to comment on the new information and possible revisions to the final rule that the Agency is considering. One of the issues EPA is requesting further comment on is establishing an alternative compliance limit for facilities that have low impingement rates, which may be applicable to Hoot Lake Plant.

[5] *Special Reliability Assessment: Resource Adequacy Impact of Potential U.S. Environmental Regulations,* at 57, NERC (October 2010).

OTP will need to wait for publication of the final rule and likely action by the MPCA before reaching a conclusion on the 316(b) rule impact.

B. Effluent Limit Guidelines

The Clean Water Act establishes a structure for regulating discharges of pollutants to surface waters of the United States. As part of the implementation, EPA issues effluent limit guidelines ("ELG") for industrial dischargers. EPA first issued ELG for steam electric power plants in 1974, with subsequent revisions in 1977 and 1982. EPA announced its decision to proceed with further possible revisions on September 15, 2009. To support the revisions, in 2010, EPA distributed a questionnaire to approximately 700 power plants, including Hoot Lake Plant. The questionnaire collected general plant information and selected technical information about the plant processes and the electric generating units. Using data from this information collection, EPA plans to propose a rulemaking in November 2012 and take final action in April 2014.

Effluent limits specific to Hoot Lake Plant are incorporated into its National Pollutant Discharge Elimination System/State Disposal System permit. The limits are based on a combination of Minnesota state water quality standards, the Federal ELG, and best professional judgment. Hoot Lake Plant's permit limits several effluent discharges, including once-through cooling water, coal pile runoff and metal cleaning wastes, and other low-volume waste sources such as floor drains and boiler blowdown. However, it should be noted that Hoot Lake Plant does not use water to transport either fly ash or bottom ash, which would otherwise be subject to the ELG. At this time Otter Tail is unable to determine how revisions to the ELG for industrial discharges would affect Hoot Lake Plant.

SUMMARY

Figure 20 - Environmental Regulatory Assessment Summary

Rule	Status	Anticipated Hoot Lake Plant Impact	Anticipated Compliance Timeframe	Likelihood of Rule impact prior to 2020 (Capital$)	Likelihood of Rule impact prior to 2020 (Operating$)
Acid Rain Program	Final	Maintain banked allowances (SO2); Operate existing low NOx burners	Ongoing	None	None
2010 SO2 and NO2 NAAQS	Final	Low impact anticipated; Minnesota has no monitored violations	2017 - 2022	Low	Low
Clean Air Interstate Rule	Final	None – Rule stayed for the State of Minnesota	None	None	None
Cross-State Air Pollution Rule	Vacated	Rule would have required SO2 allowance purchases	Unknown	Low	Possible (costs included in analysis starting in 2013)
Regional Haze Program – Best Available Retrofit Technology	Final – EPA Approved MN SIP	None – HLP2 not BART eligible and HLP3 deemed not subject to BART	None	None	None
Regional Haze Program – SIP Revisions	Next MPCA SIP due by July 31, 2018	Likely reductions of SO2, NOx, and PM	Post 2020	Low	Low
Mercury and other Hazardous Air Pollutants (MATS)	Final	Requires PM and mercury reductions, possibly HCl	April 2015	Yes (included in analysis)	Yes (included in analysis)
Minnesota TMDL	Final	70% reduction in mercury air emission; Compliance achieved through MATS	2025	Included (MATS Rule)	Included (MATS Rule)
Greenhouse Gas Regulation – Tailoring Rule	Final	PSD Review for projects that result in a significant net CO_2 increase	No PSD projects planned	Low	Low
Clean Water Act Section 316(b)	Proposed Rule	Unknown – EPA issued a NODA to request further comment on proposed rule. Final rule expected June 2013.	Up to 8 years after final rule	Moderate $0 -$2 million	Moderate
Effluent Guidelines	Proposed Rule Expected Nov. 2012	Unknown	Up to 5 years after final rule	Low	Low
Coal Combustion Residuals	Proposed Rule	Unknown – EPA proposed two significantly different options. Impact to HLP could be low due to managing an active dry ash disposal site with a synthetic liner and leachate collection.	Unknown – pending final rule	Low	Low - additional costs included after 2020

Legend: Air related | Water related | Solid waste related

Appendix B

Transmission Analysis

PUBLIC DOCUMENT - TRADE SECRET AND PRIVILEGED DATA HAS BEEN EXCISED

Appendix B - Transmission Analysis

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Appendix C

Strategist Modeling Assumptions

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Hoot Lake Scenarios

The Baseload Diversification Study evaluated three potential scenarios related to Hoot Lake Plant. The three scenarios evaluated were:

(1) *Scenario 2015 - Expedited Retirement*: This scenario assumes that Otter Tail will commence immediately with activities necessary for an early retirement of Hoot Lake Plant in 2015.

(2) *Scenario 2020 - Expected Retirement:* This scenario plans for a retirement of Hoot Lake Plant by 2020. This duration is consistent with Otter Tail's current planning horizon for the facility. It requires the $10 million MATS investment and defers the expenditures necessary for plant replacement by five years.

(3) *Scenario 2040 - Long-term Operation:* This scenario assumes preparation for a full refurbishment of the facility for long-term continued operation. This scenario assumes that Otter Tail would install equipment to meet the MATS requirement in 2015 and additional investment in 2020 to meet likely environmental regulations and upgrade existing equipment for reliable operation for another 20 years.

Sensitivities Evaluated and Primary Uncertainties

For each of the three scenarios, forty-two sensitivities were evaluated. Table 1 shows a grid of the sensitivities and primary uncertainties evaluated by the Company. The Company addressed sensitivities for varying capital costs, load growth, fuel costs, and emission costs. Items noted in the color red indicate the uncertainty that varies from reference case #1.

Figure 25 - Sensitivities Evaluated for Baseload Diversification Study

Otter Tail Power Company		Uncertainties																							
		Capital						D&E		Economic			Wind				Fuel		Emissions			
	Sensitivity	HLP Limited Retrofit	HLP Refurbish	HLP to Gas	HLP Gas Line & transmission	Combined Cycle	Simple Cycle	Demand	Energy	Inflation	Discount Rate	Energy Market limit	PTC Expiration	PTC Wind Cost	Non PTC Wind Cost	Wind Capacity Credit	Gas	Coal	Co2 cost start year	Co2 costs	SO2 costs	Nox costs
1	Reference Case	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	H	MH	M	M
2	Unlimited Market Available	M	M	M	M	M	M	M	M	M	M	H	M	M	M	M	M	M	H	MH	M	M
3	Low Wind Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	L	M	M	M	H	MH	M	M
4	Low Capital Cost	L	L	L	L	L	L	M	M	M	M	M	M	M	M	M	M	M	H	MH	M	M
5	High Capital Cost	H	H	H	H	H	H	M	M	M	M	M	M	M	M	M	M	M	H	MH	M	M
6	-50% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	M	H	MH	M	M
7	-25% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	ML	M	H	MH	M	M
8	+25% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	MH	M	H	MH	M	M
9	+50% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	H	M	H	MH	M	M
10	Low Coal Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	H	MH	M	M
11	High Coal Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	H	H	MH	M	M
12	Low load Growth	M	M	M	M	M	M	L	L	M	M	M	M	M	M	M	M	M	H	MH	M	M
13	High Load Growth	M	M	M	M	M	M	H	H	M	M	M	M	M	M	M	M	M	H	MH	M	M
14	$9/ton carbon tax starting in 2016	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	ML	M	M
15	$34/ton carbon tax starting in 2016	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	H	M	M
16	$24/ton carbon tax starting in 2016 + high coal	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	H	M	MH	M	M
17	$16/ton carbon tx starting in 2023	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	ML	M	M	M
18	Unlimited Market Available	M	M	M	M	M	M	M	M	M	M	H	M	M	M	M	M	M	ML	M	M	M
19	Low Wind Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	L	M	M	M	ML	M	M	M
20	Low Capital Cost	L	L	L	L	L	L	M	M	M	M	M	M	M	M	M	M	M	ML	M	M	M
21	High Capital Cost	H	H	H	H	H	H	M	M	M	M	M	M	M	M	M	M	M	ML	M	M	M
22	-50% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	M	ML	M	M	M
23	-25% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	ML	M	ML	M	M	M
24	+25% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	MH	M	ML	M	M	M
25	+50% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	H	M	ML	M	M	M
26	Low Coal Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	ML	M	M	M
27	High Coal Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	H	ML	M	M	M
28	Low load Growth	M	M	M	M	M	M	L	L	M	M	M	M	M	M	M	M	M	ML	M	M	M
29	High Load Growth	M	M	M	M	M	M	H	H	M	M	M	M	M	M	M	M	M	ML	M	M	M
30	Zero Externality	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	L	L	L
31	Unlimited Market Available	M	M	M	M	M	M	M	M	M	M	H	M	M	M	M	M	M	L	L	L	L
32	Low Wind Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	L	M	M	M	L	L	L	L
33	Low Capital Cost	L	L	L	L	L	L	M	M	M	M	M	M	M	M	M	M	M	L	L	L	L
34	High Capital Cost	H	H	H	H	H	H	M	M	M	M	M	M	M	M	M	M	M	L	L	L	L
35	-50% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	M	L	L	L	L
36	-25% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	ML	M	L	L	L	L
37	+25% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	MH	M	L	L	L	L
38	+50% Natural Gas Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	H	M	L	L	L	L
39	Low Coal Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	L	L	L	L
40	High Coal Cost	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	H	L	L	L	L
41	Low load Growth	M	M	M	M	M	M	L	L	M	M	M	M	M	M	M	M	M	L	L	L	L
42	High Load Growth	M	M	M	M	M	M	H	H	M	M	M	M	M	M	M	M	M	L	L	L	L

L = Low
ML = Mid-Low
M = Mid
MH = Mid-High
H = High

Table 2 provides the specific values associated with the uncertainty measures used in the forty-two sensitivities referenced in Table 1.

Figure 26 - Sensitivity Assumptions for Baseload Diversification Study
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Generation Alternatives

Table 3 lists the thermal generation alternatives that were made available to the model.

Figure 27 - Thermal Generation Alternatives for Baseload Diversification Study

Thermal Generation Alternatives					
Name	Scenario 2020 Expected Retirement	Scenario 2040 Long Term Operation	HLP to Gas	Simple Cycle (SC)*	Combined Cycle (CC)*
NamePlate ISO Capacity (MW)	137	137	122	92	146
Fuel	Coal	Coal	Natural Gas	Natural Gas	Natural Gas
Capital Costs (2012$)	$ 9,179,000	$ 125,492,000	$ 12,810,000	$ 52,900,000	$ 153,884,000
Capital Costs ($/kw)	$ 67.00	$ 916.00	$ 105.00	$ 575.00	$ 1,054.00
Capital Escalation	4%	4%	4%	4%	4%
Total Fixed O&M (2012$)	$ 6,612,334	$ 10,008,583	$ 2,432,000	$ 694,980	$ 1,961,190
2012 Variable O&M ($/mwh)	$ 0.36	$ 0.36	$ 1.30	$ 2.50	$ 2.80
Available Years	2015	2020	2015	2016-2026	2016-2026
Operating Life (years)	5	20	5	20	20
Available Scenario	2020, 2040	2040	2020	2015, 2020, 2040	2015, 2020, 2040
	* For the simple cycle (SC) and combined cycle (CC) alteratives, the capacity, capital costs, and fixed O&M are based on the Company having 50% ownership of a generic project				

Table 4 shows the detail associated with wind resource alternatives including wind generation with and without the federal Production Tax Credit.

Figure 28 - Wind Resource Alternative Assumptions for Baseload Diversification Study (nominal$)

Wind Alternatives			
Available	2013	2014-2026	2014-2026
Escalation	3%	3%	3%
Ownership	PPA	PPA	PPA
Name	**PTC WIND**	**Non PTC WIND**	**Low Non PTC WIND**
Units	Nominal$/MWh	Nominal$/MWh	Nominal$/MWh
2012	$ 33.00	$ 55.00	$ 44.00
2013	$ 33.99	$ 56.65	$ 45.32
2014	$ 35.01	$ 58.35	$ 46.68
2015	$ 36.06	$ 60.10	$ 48.08
2016	$ 37.14	$ 61.90	$ 49.52
2017	$ 38.26	$ 63.76	$ 51.01
2018	$ 39.40	$ 65.67	$ 52.54
2019	$ 40.59	$ 67.64	$ 54.11
2020	$ 41.80	$ 69.67	$ 55.74
2021	$ 43.06	$ 71.76	$ 57.41
2022	$ 44.35	$ 73.92	$ 59.13
2023	$ 45.68	$ 76.13	$ 60.91
2024	$ 47.05	$ 78.42	$ 62.73
2025	$ 48.46	$ 80.77	$ 64.62
2026	$ 49.92	$ 83.19	$ 66.55

Energy and Capacity Price Forecasts

The market energy price forecast was obtained from the Wood Mackenzie May 2012 North American Power Service product. The Wood Mackenzie forecast data was used for 2012 forward. Capacity price assumptions are shown in Table 5 and energy price assumptions are shown in Table 6. This data is presented here with permission from Wood Mackenzie for the purposes of this filing.

Figure 29 - Capacity Price Assumptions for Baseload Diversification Study
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Figure 30 - Energy Price Assumptions for Baseload Diversification Study

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Fuel Price Forecasts

Fuel price forecasts are presented in Table 7. The data shown is in nominal dollars for the base case scenario. The natural gas forecast is obtained from the Wood Mackenzie May 2012 North American Power Service product. The Powder River Basin (PRB) and lignite coal forecasts were developed using Wood Mackenzie data as a starting point and adjusted to reflect delivery and other basis cost differences not included in the Wood Mackenzie forecast.

Figure 31 - Reference Case Fuel Price per MBTU Assumptions for Baseload Diversification Study

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Emissions Costs

Table 8 lists the emissions costs used for the reference case.

Figure 32 - Reference Case Emission Cost Assumptions for Baseload Diversification Study

Reference Case Emission Cost Assumptions ($/ton)			
Source	PUC ordered	EPA - CSAPR	EPA - CSAPR
Dollars	Nominal	Nominal	Nominal
Year	**CO2**	**SO2**	**Nox**
2012	$ 21.50	$ 639.70	$ 552.15
2013	$ 22.15	$ 672.14	$ 581.59
2014	$ 22.81	$ 704.58	$ 611.03
2015	$ 23.49	$ 737.02	$ 640.47
2016	$ 24.20	$ 690.02	$ 688.80
2017	$ 24.92	$ 643.03	$ 737.13
2018	$ 25.67	$ 596.03	$ 785.46
2019	$ 26.44	$ 549.04	$ 833.78
2020	$ 27.24	$ 502.05	$ 882.11
2021	$ 28.05	$ 489.43	$ 937.55
2022	$ 28.89	$ 476.81	$ 992.98
2023	$ 29.76	$ 464.19	$ 1,048.42
2024	$ 30.65	$ 451.56	$ 1,103.86
2025	$ 31.57	$ 438.94	$ 1,159.30
2026	$ 32.52	$ 426.32	$ 1,214.73

Inflation Rate and Cost Escalation

Otter Tail uses an annual 3% inflation rate for future operation and maintenance cost variables. The annual cost escalation rate for capital costs for new thermal generation was 4%. Fuel and energy price forecasts were obtained with embedded escalation assumptions year-over-year.

Utility Discount Rate and Weighted Cost of Capital

For this analysis, the weighted cost of capital is based on a projected 50/50 split between debt and equity. The interest for long term debt is estimated at 7.5% and the allowed return on equity is at 10.75%, resulting in a weighted cost of capital of 9.125%. The utility discount rate is set equal to the weighted cost of capital.

Appendix D

Strategist Modeling Runs

Retire Hoot Lake 2015 Scenario Case Summary w/ End Effects (SCENARIO 2015)

SCENARIO 2015

Sensitivity:	1-Base (Ordered)	2-Mkt Available Long Term	3-Low Wind Cost	4-Low Capital Cost	5-High Capital Cost	6 -50% Natural Gas	7 -25% Natural Gas	8 +25% Natural Gas	9 +50% Natural Gas	10 Low Coal	11 High Coal	12 Low Load Growth	13 High Load Growth	14 $9/Ton Carbon Tax	15 $34/Ton Carbon Tax	16 $24/Ton + High Coal (+20%)	17 $16/Ton Carbon Tax	18 Mkt Available Long Term	19 Low Wind Cost	20 Low Capital Cost	21 High Capital Cost	22 -50% Natural Gas	23 -25% Natural Gas	24 +25% Natural Gas
Mkt Energy (Last Yr)	2017	N/A	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	N/A	2017	2017	2017	2017	2017	2017
Mkt Forecast Basis	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012
CO2 Tax/ton(Start Yr)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$21.50 (2012)	$9.00 (2016)	$34.00 (2016)	$21.50 (2016)	$16.00 (2023)	$16.00 (2023)	$16.00 (2023)	$16.00 (2023)	$16.00 (2023)	$16.00 (2023)	$16.00 (2023)	$16.00 (2023)
Assumption Sensitivity	N/A	N/A	-20%	-30%	+30%	-50%	-25%	+25%	+50%	-10%	+20%			$9/Ton	$34/Ton	$21.50/Ton	N/A		-20%	-30%	+30%	-50%	-25%	+25%
Plan Year RESOURCE(Capacity)																								
2012																								
2013	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)		PTC Wind (150)	PTC Wind (150)
2014																								
2015	HLtoGas(122)	Mkt (59)	Wind (50) HLtoGas (122)	HLtoGas (122)	HLtoGas(122)	Mkt (59)	Mkt (59)	HLtoGas(122)	Mkt (59)	HLtoGas(122)	Mkt (59)	Mkt (7)	HLtoGas (122)	HLtoGas (122)	Mkt (59)	HLtoGas (122)	HLtoGas (122)	Mkt (59)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)
2016		Mkt (63)				CC (146) SC (92)	CC (146)		SC (92)		CC (146)	Mkt (11)	CC (146)		CC (146)			Mkt (63)				CC (146)	SC (92)	
2017	Mkt (42)	SC (92) Mkt (66)	Mkt (32)	CC (146)	Mkt (42)		Mkt (17)	Mkt (42)	Mkt (66)	Mkt (42)	Mkt (17)	SC (92) Mkt (14)		Mkt (42)	Mkt (17)	Mkt (42)	SC (92)	SC (92) Mkt (66)	SC (92)	CC (146)	Mkt (42)			Mkt (42)
2018	CC (146)	Mkt (73)	CC (146)		SC (92)		SC (92)	CC (146)	CC (146)	CC (146)	SC (92)	Mkt (20)		CC (146)	SC (92)	CC (146)		Mkt (73)			SC (92)			CC (146)
2019		Mkt (80)										Mkt (27)						Mkt (80)						
2020	SC (92)	Mkt (88)	Mkt (29)	SC (92)	CC (146)			Mkt (39)		SC (92)		SC (92)	CC (146)	SC (92)		SC (92)	CC (146)	Mkt (88)	CC (146)	Mkt (39)	CC (146)	CC (146)	CC (146)	SC (92)
2021		SC (92)	SC (92)					SC (92)										SC (92)		CC (146)				
2022		Mkt (18)																Mkt (18)						
2023		Mkt (35)																Mkt (35)						
2024		Mkt (46)											Mkt (2)					Mkt (46)						
2025	Mkt (8)	Mkt (57)		Mkt (8)	Mkt (8)	Mkt (8)	Mkt (8)	Mkt (8)	Wind (50)	Mkt (8)	Mkt (8)	Mkt (3)	SC (92)	Mkt (8)	Mkt (8)	Mkt (8)	Mkt (8)	Mkt (57)	Wind (50)		Mkt (8)		Mkt (8)	Mkt (8)
2026	Mkt (20)	Mkt (69)	Wind (50)	Mkt (20)	Mkt (20)	Mkt (20)	Mkt (20)	Mkt (20)	Mkt (10)	Mkt (20)	Mkt (20)	Mkt (15)		Mkt (20)	Wind (50) Mkt (10)	Mkt (20)	Mkt (20)	Mkt (69)	Wind (50)		Mkt (20)	Mkt (2)	Mkt (20)	Mkt (20)
Planning Period 2012$	$2,716,676	$2,696,963	$2,712,653	$2,673,092	$2,757,797	$2,536,690	$2,638,367	$2,765,568	$2,810,980	$2,650,727	$2,840,221	$2,356,075	$3,184,971	$2,028,524	$2,699,307	$2,502,557	$1,883,250	$1,837,583	$1,883,745	$1,852,532	$1,921,862	$1,748,832	$1,828,622	$1,931,291
End Effects NPV	$2,270,332	$2,194,261	$2,263,362	$2,199,480	$2,341,183	$2,055,482	$2,171,810	$2,340,500	$2,400,350	$2,219,945	$2,364,874	$1,926,727	$2,738,803	$1,886,831	$2,625,462	$2,364,874	$2,160,284	$1,960,933	$2,148,874	$2,052,379	$2,231,136	$1,846,571	$2,004,284	$2,233,356
Total ($000)	$4,987,008	$4,891,224	$4,976,015	$4,872,572	$5,098,980	$4,592,172	$4,810,177	$5,106,068	$5,211,330	$4,870,672	$5,205,095	$4,282,802	$5,923,774	$3,915,355	$5,324,769	$4,867,431	$4,043,534	$3,798,515	$4,032,619	$3,904,911	$4,152,998	$3,595,404	$3,832,907	$4,164,647
Difference from Base	0.00%	-0.73%	-0.15%	-1.60%	1.51%	-6.63%	-2.88%	1.80%	3.47%	-2.43%	4.55%	-13.27%	17.24%	-25.33%	-0.64%	-7.88%	-30.68%	-32.36%	-30.66%	-31.81%	-29.26%	-35.63%	-32.69%	-28.91%

Limited Retrofit and Retire Hoot Lake 2020 Scenario Case Summary w/ End Effects (SCENARIO 2020)

SCENARIO 2020

Assumption:	1-Base (Ordered)	2-Mkt Available Long Term	3-Low Wind Cost	4-Low Capital Cost	5-High Capital Cost	6 -50% Natural Gas	7 -25% Natural Gas	8 +25% Natural Gas	9 +50% Natural Gas	10 Low Coal	11 High Coal	12 Low Load Growth	13 High Load Growth	14 $9/Ton Carbon Tax	15 $34/Ton Carbon Tax	16 $24/Ton + High Coal (+20%)	17 $16/Ton Carbon Tax	18 Mkt Available Long Term	19 Low Wind Cost	20 Low Capital Cost	21 High Capital Cost	22 -50% Natural Gas	23 -25% Natural Gas	24 +25% Natural Gas
Plan Year RESOURCE(Capacity)																								
2012																								
2013	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)		PTC Wind (150)	PTC Wind (150)
2014																								
2015																								
2016													SC (92)											
2017	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	CC (146)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)			Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (56)	Mkt (26)	Mkt (26)
2018	SC (92)	Mkt (33)	SC (92)	SC (92)	SC (92)		SC (92)	SC (92)	SC (92)	SC (92)	SC (92)		CC (146)	SC (92)	SC (92)	SC (92)	SC (92)	Mkt (33)	SC (92)	CC (146)	SC (92)	CC (146)	SC (92)	SC (92)
2019		Mkt (40)																Mkt (40)						
2020	CC (146)	SC (92) Mkt (88)	CC (146)	CC (146)	CC (146)	SC (92)	CC (146)	CC (146)	CC (146)	CC (146)	CC (146)	SC (92) Mkt (35)		CC (146)	CC (146)	CC (146)	CC (146)	SC (92) Mkt (88)	CC (146)	Mkt (39)	CC (146)	CC (146)	CC (146)	CC (146)
2021		SC (92) mkt (7)										SC (92)	SC (92)					SC (92) Mkt (7)		CC (146)				
2022		Mkt (18)	Wind (50)															Mkt (18)						
2023		Mkt (35)																Mkt (35)						
2024		Mkt (46)																Mkt (46)						
2025	Mkt (8)	Mkt (57)		Mkt (8)	Mkt (8)	Mkt (8)	Mkt (8)	Mkt (8)	Wind (50)	Mkt (8)	Mkt (8)	Mkt (3)		Mkt (8)	Mkt (8)	Mkt (8)	Mkt (8)	Mkt (57)	Wind (50)		Mkt (8)		Mkt (8)	Mkt (8)
2026	Mkt (20)	Mkt (69)	Wind (50)	Mkt (20)	Mkt (20)	Mkt (20)	Mkt (20)	Mkt (20)	Mkt (10)	Mkt (20)	Mkt (20)	Mkt (15)		Mkt (20)	Wind (50) Mkt (10)	Mkt (20)	Mkt (20)	Mkt (69)	Wind (50)		Mkt (20)	Mkt (2)	Mkt (20)	Mkt (20)
Planning Period 2012$	$2,708,950	$2,707,219	$2,707,915	$2,674,668	$2,743,232	$2,575,918	$2,656,570	$2,744,265	$2,777,518	$2,637,530	$2,845,004	$2,366,022	$3,185,430	$2,009,593	$2,711,184	$2,506,691	$1,856,900	$1,823,544	$1,857,395	$1,839,217	$1,891,182	$1,760,205	$1,820,201	$1,890,588
End Effects NPV	$2,268,328	$2,192,257	$2,261,358	$2,197,476	$2,339,180	$2,053,479	$2,169,806	$2,338,496	$2,398,347	$2,217,941	$2,362,871	$1,924,724	$2,733,654	$1,884,828	$2,623,459	$2,362,871	$2,158,280	$1,958,929	$2,146,870	$2,050,376	$2,229,132	$1,844,568	$2,002,281	$2,231,353
Total ($000)	$4,977,278	$4,899,476	$4,969,273	$4,872,144	$5,082,411	$4,629,397	$4,826,376	$5,082,761	$5,175,864	$4,855,471	$5,207,875	$4,290,746	$5,919,084	$3,894,421	$5,334,643	$4,869,561	$4,015,180	$3,782,473	$4,004,265	$3,889,593	$4,120,314	$3,604,774	$3,822,481	$4,121,940
Difference from Base	0.00%	-0.06%	-0.04%	-1.27%	1.27%	-4.91%	-1.93%	1.30%	2.53%	-2.64%	5.02%	-12.66%	17.59%	-25.82%	0.08%	-7.47%	-31.45%	-32.68%	-31.43%	-32.11%	-30.19%	-35.02%	-32.81%	-30.21%

Retrofit and Refurbish Hoot Lake 2015/2020 Ordered Scenario Case Summary w/ End Effects (SCENARIO 2040)

SCENARIO 2040

Assumption:	1-Base (Ordered)	2-Mkt Available Long Term	3-Low Wind Cost	4-Low Capital Cost	5-High Capital Cost	6 -50% Natural Gas	7 -25% Natural Gas	8 +25% Natural Gas	9 +50% Natural Gas	10 Low Coal	11 High Coal	12 Low Load Growth	13 High Load Growth	14 $9/Ton Carbon Tax	15 $34/Ton Carbon Tax	16 $24/Ton + High Coal (+20%)	17 $16/Ton Carbon Tax	18 Mkt Available Long Term	19 Low Wind Cost	20 Low Capital Cost	21 High Capital Cost	22 -50% Natural Gas	23 -25% Natural Gas	24 +25% Natural Gas
Plan Year RESOURCE(Capacity)																								
2012																								
2013	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (100)	PTC Wind (150)	PTC Wind (100)	PTC Wind (100)	PTC Wind (150)	PTC Wind (50)	PTC Wind (50)	PTC Wind (150)
2014																								
2015																								
2016													CC (146)											
2017	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	CC (146)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)	Mkt (26)			Mkt (26)	Mkt (26)	Mkt (26)	Mkt (36)	Mkt (26)	Mkt (36)	Mkt (36)	Mkt (26)	Mkt (46)	Mkt (46)	Mkt (26)
2018	SC (92)	Mkt (33)	SC (92)	CC (146)	SC (92)		CC (146)	SC (92)	SC (92)	SC (92)	SC (92)			SC (92)	CC (146)	SC (92)	CC (146)	Mkt (33)	CC (146)	CC (146)	SC (92)	CC (146)	CC (146)	SC (92)
2019		Mkt (40)																Mkt (40)						
2020		Mkt (48)																Mkt (48)						
2021		Mkt (64)										Mkt (11)						Mkt (64)						
2022		Mkt (75)										SC (92)	SC (92)					Mkt (75)						
2023		Mkt (92)																Mkt (92)						
2024	Mkt (6)	SC (92) Mkt (6)	Wind (50)		Mkt (6)			Mkt (6)	Mkt (6)	Mkt (6)	Mkt (6)			Mkt (6)		Mkt (6)		SC (92) Mkt (6)			Mkt (6)			Mkt (6)
2025	Mkt (17)	Mkt (17)	Mkt (7)		Mkt (17)			Mkt (17)	Mkt (17)	Mkt (17)	Mkt (17)			Mkt (17)		Mkt (17)		Mkt (17)			Mkt (17)			Mkt (17)
2026	Mkt (29)	Mkt (29)	Mkt (19)		Mkt (29)			Mkt (29)	Mkt (29)	Mkt (29)	Mkt (29)			Mkt (29)		Mkt (29)		Mkt (29)			Mkt (29)			Mkt (29)
Planning Period 2012$	$2,763,522	$2,741,050	$2,763,079	$2,750,609	$2,779,981	$2,668,846	$2,736,790	$2,781,611	$2,798,787	$2,684,971	$2,918,754	$2,422,501	$3,230,357	$2,042,326	$2,792,248	$2,580,440	$1,900,401	$1,842,357	$1,900,401	$1,868,363	$1,902,904	$1,829,340	$1,872,347	$1,903,751
End Effects NPV	$2,399,389	$2,361,857	$2,395,700	$2,363,594	$2,425,120	$2,266,717	$2,348,030	$2,426,389	$2,453,251	$2,328,263	$2,540,994	$2,075,537	$2,840,817	$1,963,532	$2,805,133	$2,540,994	$2,225,416	$2,110,419	$2,225,416	$2,170,538	$2,289,891	$2,026,376	$2,131,988	$2,283,110
Total ($000)	$5,162,911	$5,102,907	$5,158,779	$5,114,202	$5,205,101	$4,935,563	$5,084,820	$5,208,000	$5,252,038	$5,013,234	$5,459,748	$4,498,038	$6,071,174	$4,005,858	$5,597,381	$5,121,434	$4,125,817	$3,952,776	$4,125,817	$4,038,900	$4,192,795	$3,855,716	$4,004,335	$4,186,861
Difference from Base	0.00%	-0.81%	-0.02%	-0.47%	0.60%	-3.43%	-0.97%	0.65%	1.28%	-2.84%	5.62%	-12.34%	16.89%	-26.10%	1.04%	-6.62%	-31.23%	-33.33%	-31.23%	-32.39%	-31.14%	-33.80%	-32.25%	-31.11%

SCENARIO 2015

Retire Hoot Lake 2015

Sensitivity:	25 +50% Natural Gas	26 Low Coal	27 High Coal	28 Low Load Growth	29 High Load Growth	30 Zero Externality	31 Mkt Available Long Term	32 Low Wind Cost	33 Low Capital Cost	34 High Capital Cost	35 -50% Natural Gas	36 -25% Natural Gas	37 +25% Natural Gas	38 +50% Natural Gas	39 Low Coal	40 High Coal	41 Low Load Growth	42 High Load Growth
Mkt Energy (Last Yr)	2017	2017	2017	2017	2017	2017	N/A	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017
Mkt Forecast Basis	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012	WM May 2012
CO2 Tax/ton(Start Yr)	$16.00 (2023)	$16.00 (2023)	$16.00 (2023)	$16.00 (2023)	$16.00 (2023)	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities
Assumption Sensitivity	+50%	-10%	+20%			$0/Ton		-20%	-30%	+30%	-50%	-25%	+25%	+50%	-10%	+20%		
Plan Year RESOURCE(C																		
2012																		
2013	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (50)	PTC Wind (150)	PTC Wind (100)	PTC Wind (150)		PTC Wind (100)	PTC Wind (150)	PTC Wind (150)	PTC Wind (100)	PTC Wind (150)	PTC Wind (50)	PTC Wind (150)
2014																		
2015	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	HLtoGas (122)	Mkt (27)	HLtoGas (122)
2016					CC (146)						SC (92)	SC (92)					SC (92)	CC (146)
2017	Mkt (42)	SC (92)	SC (92)			SC (92)	Mkt (62)	SC (92)	CC (146)	Mkt (42)			Mkt (42)	Mkt (42)	Mkt (52)	SC (92)	Mkt (34)	
2018	CC (146)						Mkt (68)			SC (92)			CC (146)	CC (146)	CC (146)		SC (92)	
2019				Mkt (3)			Mkt (76)											
2020	Mkt (39)	CC (146)	CC (146)	CC (146)	CC (146)	CC (146)	SC (184)	CC (146)	SC (92)	CC (146)	SC (92)	SC (92)	SC (92)	Mkt (39)	SC (92)	CC (146)		SC (92)
2021	SC (92)			Mkt (3)			Mkt (27)				SC (92)	Mkt (17)		SC (92)				SC (92)
2022				Mkt (13)			Mkt (38)					SC (92)						
2023				Mkt (30)			Mkt (55)										Mkt (1)	
2024				Mkt (41)	Mkt (2)		Mkt (66)		Mkt (7)						Mkt (7)		Mkt (12)	
2025	Mkt (8)	Mkt (8)	Mkt (8)	Mkt (52)	Mkt (13)	Mkt (8)	Mkt (77)	Mkt (8)	Mkt (18)	Mkt (8)			Mkt (8)	Mkt (8)	Mkt (18)	Mkt (8)	Mkt (23)	
2026	Mkt (20)	Mkt (20)	Mkt (20)	Mkt (63)	Mkt (26)	Mkt (20)	Mkt (89)	Mkt (20)	Mkt (30)	Mkt (20)	Mkt (2)		Mkt (20)	Mkt (20)	Mkt (30)	Mkt (20)	Mkt (35)	
Planning Period 2012$	$1,978,058	$1,816,815	$2,015,858	$1,633,926	$2,235,899	$1,683,229	$1,618,123	$1,683,229	$1,635,292	$1,721,719	$1,536,186	$1,625,965	$1,731,072	$1,777,654	$1,611,112	$1,815,163	$1,427,052	$2,008,932
End Effects NPV	$2,265,199	$2,118,133	$2,236,659	$1,796,811	$2,538,887	$1,556,331	$1,383,026	$1,556,331	$1,491,042	$1,627,183	$1,374,984	$1,483,235	$1,619,825	$1,682,993	$1,504,259	$1,668,312	$1,284,330	$1,921,971
Total ($000)	$4,243,257	$3,934,948	$4,252,517	$3,430,737	$4,774,786	$3,239,560	$3,001,149	$3,239,560	$3,126,334	$3,348,902	$2,911,170	$3,109,200	$3,350,897	$3,460,647	$3,115,371	$3,483,475	$2,711,381	$3,930,903
Difference from Base	-27.19%	-33.12%	-25.80%	-39.86%	-17.70%	-38.04%	-40.44%	-38.04%	-39.81%	-36.62%	-43.45%	-40.15%	-36.28%	-34.57%	-40.70%	-33.18%	-47.47%	-26.05%

Limited Retrofit and F

Assumption:	25 +50% Natural Gas	26 Low Coal	27 High Coal	28 Low Load Growth	29 High Load Growth	30 Zero Externality	31 Mkt Available Long Term	32 Low Wind Cost	33 Low Capital Cost	34 High Capital Cost	35 -50% Natural Gas	36 -25% Natural Gas	37 +25% Natural Gas	38 +50% Natural Gas	39 Low Coal	40 High Coal	41 Low Load Growth	42 High Load Growth
Plan Year RESOURCE(C																		
2012																		
2013	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (150)	PTC Wind (100)		PTC Wind (100)	PTC Wind (100)	PTC Wind (100)		PTC Wind (50)	PTC Wind (150)	PTC Wind (150)	PTC Wind (100)	PTC Wind (150)	PTC Wind (50)	PTC Wind (150)
2014																		
2015																		
2016																		SC (92)
2017	Mkt (26)	Mkt (26)	Mkt (26)		CC (146)	Mkt (36)	Mkt (56)	Mkt (36)	Mkt (36)	Mkt (36)	SC (92)	Mkt (46)	Mkt (26)	Mkt (26)	Mkt (36)	Mkt (26)		
2018	SC (92)	SC (92)	SC (92)			SC (92)	Mkt (63)	SC (92)	SC (92)	SC (92)		SC (92)	SC (92)	SC (92)	SC (92)	SC (92)		SC (92)
2019							Mkt (70)										Mkt (7)	
2020	CC (146)	CC (146)	CC (146)	CC (146)	CC (146)	CC (146)	SC (92)	CC (146)	CC (146)	CC (146)	SC (92)	SC (92)	CC (146)	CC (146)	CC (146)	CC (146)	SC (92)	CC (146)
							SC (92)				Mkt (21)	Mkt (11)					SC (92)	
							Mkt (21)											
2021				Mkt (3)			Mkt (37)				SC (92)	SC (92)						
2022				Mkt (13)			Mkt (48)											
2023				Mkt (30)			Mkt (65)										Mkt (1)	
2024				Mkt (41)	Mkt (2)	Mkt (7)	Mkt (76)	Mkt (7)	Mkt (7)	Mkt (7)					Mkt (7)		Mkt (12)	Mkt (2)
2025	Mkt (8)	Mkt (8)	Mkt (8)	Mkt (52)	Mkt (13)	Mkt (18)	Mkt (87)	Mkt (18)	Mkt (18)	Mkt (18)		Mkt (8)	Mkt (8)	Mkt (8)	Mkt (18)	Mkt (8)	Mkt (23)	Mkt (13)
2026	Mkt (20)	Mkt (20)	Mkt (20)	Mkt (63)	Mkt (26)	Mkt (30)	Mkt (99)	Mkt (30)	Mkt (30)	Mkt (30)	Mkt (2)	Mkt (20)	Mkt (20)	Mkt (20)	Mkt (30)	Mkt (20)	Mkt (35)	Mkt (26)
Planning Period 2012$	$1,924,251	$1,784,821	$2,000,581	$1,624,522	$2,207,992	$1,643,874	$1,595,976	$1,643,874	$1,609,592	$1,678,156	$1,538,626	$1,603,789	$1,687,031	$1,720,664	$1,570,471	$1,796,492	$1,403,561	$1,968,036
End Effects NPV	$2,263,196	$2,116,130	$2,234,656	$1,794,807	$2,536,883	$1,559,890	$1,380,436	$1,559,890	$1,489,039	$1,630,742	$1,372,981	$1,485,446	$1,617,822	$1,680,989	$1,502,255	$1,666,308	$1,282,326	$1,919,968
Total ($000)	$4,187,447	$3,900,950	$4,235,237	$3,419,330	$4,744,875	$3,203,764	$2,976,412	$3,203,764	$3,098,631	$3,308,898	$2,911,607	$3,089,235	$3,304,853	$3,401,653	$3,072,726	$3,462,800	$2,685,887	$3,888,004
Difference from Base	-28.97%	-34.11%	-26.15%	-40.03%	-18.49%	-39.32%	-41.09%	-39.32%	-40.58%	-38.05%	-43.20%	-40.80%	-37.72%	-36.48%	-42.03%	-33.68%	-48.19%	-27.35%

SCENARIO 2020

Retrofit and Refurbisl

Assumption:	25 +50% Natural Gas	26 Low Coal	27 High Coal	28 Low Load Growth	29 High Load Growth	30 Zero Externality	31 Mkt Available Long Term	32 Low Wind Cost	33 Low Capital Cost	34 High Capital Cost	35 -50% Natural Gas	36 -25% Natural Gas	37 +25% Natural Gas	38 +50% Natural Gas	39 Low Coal	40 High Coal	41 Low Load Growth	42 High Load Growth
Plan Year RESOURCE(C																		
2012																		
2013	PTC Wind (150)	PTC Wind (100)	PTC Wind (150)	PTC Wind (100)	PTC Wind (100)	PTC Wind (50)		PTC Wind (50)	PTC Wind (50)	PTC Wind (100)			PTC Wind (100)	PTC Wind (150)		PTC Wind (100)		PTC Wind (100)
2014																		
2015																		
2016					SC (92)													SC (92)
2017	Mkt (26)	Mkt (36)	Mkt (26)			Mkt (46)	Mkt (56)	Mkt (46)	SC (92)	Mkt (36)	SC (92)	SC (92)	Mkt (36)	Mkt (26)	Mkt (56)	Mkt (36)	Mkt (4)	
2018	SC (92)	CC (146)	CC (146)		CC (146)	SC (92)	Mkt (63)	SC (92)		SC (92)			SC (92)	SC (92)	SC (92)	SC (92)	Mkt (10)	CC (146)
2019							Mkt (70)										Mkt (17)	
2020				Mkt (5)			Mkt (78)										SC (92)	
2021				Mkt (21)			Mkt (94)											
2022				SC (92)			SC (92)				SC (92)	SC (92)			Mkt (8)			
2023						SC (92)	Mkt (25)	SC (92)	SC (92)	Mkt (5)			Mkt (5)		SC (92)	Mkt (5)		
2024	Mkt (6)						Mkt (36)			Mkt (16)			Mkt (16)	Mkt (6)		Mkt (16)		
2025	Mkt (17)						Mkt (47)			Mkt (27)			Mkt (27)	Mkt (17)		Mkt (27)		
2026	Mkt (29)						Mkt (59)			Mkt (39)			Mkt (39)	Mkt (29)		Mkt (39)	Mkt (5)	
Planning Period 2012$	$1,921,040	$1,820,089	$2,066,021	$1,638,457	$2,222,432	$1,651,860	$1,601,230	$1,651,860	$1,631,448	$1,675,247	$1,593,569	$1,623,326	$1,678,163	$1,704,832	$1,567,129	$1,818,232	$1,414,488	$1,973,286
End Effects NPV	$2,212,570	$2,169,852	$2,325,504	$1,974,949	$2,687,699	$1,601,242	$1,489,074	$1,601,242	$1,559,537	$1,625,245	$1,513,386	$1,559,337	$1,629,818	$1,652,335	$1,528,474	$1,745,183	$1,336,934	$1,946,145
Total ($000)	$4,133,610	$3,989,941	$4,391,525	$3,613,406	$4,910,130	$3,253,102	$3,090,304	$3,253,102	$3,190,985	$3,300,492	$3,106,955	$3,182,662	$3,307,981	$3,357,167	$3,095,604	$3,563,415	$2,751,422	$3,919,431
Difference from Base	-30.49%	-34.14%	-25.24%	-40.71%	-19.58%	-40.23%	-42.06%	-40.23%	-40.96%	-39.38%	-42.34%	-41.26%	-39.27%	-38.31%	-43.29%	-34.21%	-48.82%	-28.60%

SCENARIO 2040

Appendix E

Buell Division of Fisher-Klosterman, Inc.

Feasibility and Cost Analysis and Summary

PUBLIC DOCUMENT - TRADE SECRET AND PRIVILEGED DATA HAS BEEN EXCISED

THIS DOCUMENT IS TRADE SECRET
IN ITS ENTIRETY

Appendix F

MISO Hourly Based Analysis

PUBLIC DOCUMENT - TRADE SECRET AND PRIVILEGED DATA HAS BEEN EXCISED

Appendix F - MISO Hourly Based Analysis

NOTE: *This Appendix was added at the request of the DOC to discuss the impacts of MISO "Day Ahead" vs. "Real Time" prices and their impact on the profitability and operation of Hoot Lake Plant.*

To make a reasonable comparison between how a baseload unit is dispatched and how a simple-cycle gas unit is dispatched, it's important to understand the operational characteristics of each of the two units.

At the Hoot Lake Plant, we make commitment and/or decommitment decisions when prices are expected to persist for many days or weeks. It is not considered prudent to commit/decommit the units for short periods of time (less than a week) due to the stresses that cooling and reheating places on the equipment. Once operating, the unit will be able to be dispatched between minimum and maximum loads. For Hoot Lake 2, we operate from **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**. For Hoot Lake 3, we generally operate from **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**. In other words, when the units are online, Unit 2 is not operated lower than **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**, and Unit 3 is not operated below **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**. When market prices are below unit cost, they will operate at minimum dispatch levels.

The following graph provides the day-ahead prices at Hoot Lake Plant for 2010 – June 2012. Day-ahead prices are of most interest as the company meets the needs of retail customers in the day-ahead market. As market prices have fallen, there are a large number of hours when market prices are below the approximate cost of the plant (red line).

Figure 33 - Historic day ahead LMP at HLP

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…TRADE SECRET DATA ENDS]

The next chart looks more closely at the period from January through June of 2012:

Figure 34 - Recent term day ahead LMP at HLP

[TRADE SECRET DATA BEGINS…

…TRADE SECRET DATA ENDS]

As an example of unit decommitments for economy, the company took the units offline in April and May (Unit 2: May 7 – May 22, Unit 3: April 3 – May 14), expecting that prices would remain low. We have been cautious with decommitments this year as we also need to meet minimum contractual requirements for both fuel and freight.

A simple cycle gas unit is capable of being committed quickly (often in less than 10 minutes) and is capable of one or more start cycles daily. At $2.50/MMBTU, a simple cycle natural gas turbine (with a heat rate of approximately 10,000 BTU/kwhr) has a cost per MWh very similar to Hoot Lake Plant—excluding start-up and variable O&M costs.

Dispatch Analysis

The following results summarize analysis completed by the company over the period from January 1, 2007 through June 30, 2012. The analysis compares the net MISO market revenues

for Otter Tail's retail customers between the Hoot Lake plants as they exist today and a hypothetical simple-cycle natural gas peaking plant. The assumptions in the analysis include:

Hoot Lake Plant:

- Analysis is simplified to only include day-ahead market results
- Actual plant clearing in the day-ahead market was used
- Actual fuel costs were used in determining net profitability

Simple Cycle Gas:

- Simple cycle natural gas turbine
- Analysis is simplified to only include day-ahead market prices and anticipated results
- 125 MW nameplate (to be equal to the maximum economic generation on Hoot Lake)
- 10,000 BTU/kwhr Heat Rate
- $4,500 start-up cost
- Henry Hub natural gas price (EIA)
- 3 hour minimum run time
- No minimum down time
- The analysis looked at all day-ahead LMP values for the period, and whenever the potential revenue generated by the day-ahead market exceeded the amount of operating and start-up costs, the unit was assumed to have cleared the market and operated in real-time to match the day-ahead commitment.

For both cases:

- No assumptions were made regarding actual real-time operations or the impact of imbalances between the day-ahead and real-time markets
- No sales of ancillary services were considered
- The impact of congestion between the generation and the Otter Tail load zone is ignored
- All analysis is based on historical data

The results of the analysis demonstrate the following:

Figure 35 - MISO Hourly analysis of HLP compared to theoretical NG-fired CT

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…TRADE SECRET DATA ENDS]

The Net Customer Benefit calculation for the existing coal plant is the day-ahead cleared schedule multiplied with the day-ahead LMP less the fuel cost. For the Simple Cycle Gas unit, the net profit is the estimated day-ahead schedule multiplied by the day-ahead LMP less the fuel cost and start-up cost.

The underlying market prices embedded in the analysis follow:

Figure 36 - MISO Hourly analysis, historical fuel prices

Energy Market Data

	2007	2008	2009	2010	2011	2012 (YTD June)
Henry Hub (Natural Gas $/MMBTU)	$6.94	$8.85	$3.92	$4.37	$3.98	$2.36

[TRADE SECRET DATA BEGINS…

Average Hoot Lake DA LMP ($/MWh)

… TRADE SECRET DATA ENDS]

Important observations from the data and factors to keep in mind when reviewing this analysis include:

- Until 2012, profitability at the coal unit significantly exceeded profitability at a simple cycle natural gas turbine—even with the increased flexibility afforded the simple cycle turbine.
- The net profits from the coal unit are obtained with minimal capital expenditure. To obtain the net profits from the gas unit, a major capital expenditure would be required.
- Future prices will yield results different from the historical analysis contained in this analysis. As shown above, various historical periods yield drastically different results based on market conditions.
- Natural gas prices during the analysis period were at 10-year lows
- Natural gas prices have historically been more volatile than coal prices

Negative Real-Time LMP

The Department also asked about an instance on June 20, 2012 when the real-time LMP at Big Stone plant was below the unit cost. The following table describes the financial outcome.

Figure 37 - MISO hourly analysis - specific low real-time LMP example

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…TRADE SECRET DATA ENDS]

As noted in the example, the unit cleared in the day-ahead market since the day-ahead price was in excess of unit cost. The net customer benefit in the day-ahead market for Otter Tail's portion of the Big Stone Plant generation was $591.36 for hour ending 11 on June 20, 2012.

In the real-time market, the LMP price was significantly below the unit cost. Therefore, the unit operated at minimum loads (106.3MW). Since the unit output had been sold in the day-ahead market, the company must purchase any energy sold but not delivered due to price at the real-time LMP (-$342.63/MWh). Likewise, the company is able to avoid burning additional fuel at a cost of $17.26/MWh, yielding a significant benefit in excess of day-ahead results.

Therefore, a scenario with high day-ahead prices and significantly lower real-time prices can result in a significant benefit for retail customers—ultimately passed back to retail customers in Minnesota through the fuel clause adjustment.

CERTIFICATE OF SERVICE

RE: In the Matter of Otter Tail Power Company's 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 to all other persons on the attached service list by electronic service or by First Class mail.

Otter Tail Power Company
Compliance Filing – Baseload Diversification Study 2012-2026

Dated this **3rd** day of **October 2012**.

/s/ WENDI A. OLSON
Wendi A. Olson, Regulatory Assistant
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