MINNESOTA
DEPARTMENT OF
COMMERCE

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May 2, 2014

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 7th Place East

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E017/RP-13-961

Dear Dr. Haar:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Otter Tail Power Company's Application for 2014-2028 Resource Plan Approval.

The petition was filed on June 25, 2010 by:

Brian Draxten
Manager, Resource Planning
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, MN 56538-0496

The Department **provides initial recommendations and requests that Otter Tail provide further information in reply comments. The Department will provide final recommendations subsequently.** The Department's team of Craig Addonizio, Adam Heinen, Holly Lahd, Susan Peirce and Chris Davis is available to answer any questions the Commission may have.

Sincerely,

/s/ CHRISTOPHER T. DAVIS
Rates Analyst

CTD/sm
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE,
DIVISION OF ENERGY RESOURCES

DOCKET NO. E017/RP-13-961

I. INTRODUCTION

A. OVERVIEW OF THE FILING

Minnesota Rules part 7843 require electric utilities to file proposed integrated resource plans (IRP) every two years. On March 25, 2013 the Commission approved Otter Tail Power Company's (OTP, Otter Tail, or the Company) Baseload Diversification Study. Order Point 5 stated that the Commission was closing out the 2010 IRP docket and set a deadline of December 1, 2013 for the Company to submit its next IRP. On December 1, 2013 Otter Tail submitted a resource plan (2013 IRP) covering planning years 2014-2028.

B. COMPANY BACKGROUND

Otter Tail is an investor-owned utility headquartered in Fergus Falls, Minnesota. Otter Tail is a winter-peaking utility serving about 130,000 customers in 422 communities in Minnesota, North Dakota, and South Dakota[1]. In 2012 the Company's energy to serve retail sales came from the following fuel sources: 64 percent coal, 15 percent wind and hydro, 1 percent natural gas, and 20 percent purchases (fuel source unknown). Table 1-1 in Appendix C of OTP's filing shows that the Company's 2013 planning capacity of approximately 780 MW consisted of 68 percent coal, 5 percent wind, 5 percent natural gas, 1 percent hydro, 8 percent oil, and 13 percent purchases (fuel source unknown). In addition, OTP has approximately 12 MW of summer demand direct load control.

[1] Approximately 60,600 Minnesota customers; 57,600 North Dakota customers, and 11,600 South Dakota customers.

C. SUMMARY OF OTP'S PLANNING PROCESS

OTP used the following steps in its 2013 IRP planning process:

- OTP developed three scenarios to forecast the levels of uncontrolled (uninterrupted) sales: low, base, and high.
- OTP calculated its reserve obligations by subtracting its accredited demand response from the peak demand forecast and multiplying the net demand by 1 plus the required reserve margin (currently about 6.2 percent).
- OTP calculated its resource needs by comparing its existing resources with its resource obligations.
- OTP considered the following natural gas supply-side resource alternatives:
    - 311 MW combined cycle intermediate plant (CC);
    - 49 MW combustion turbine peaking plant (CT);
    - 101 MW CT;
    - 211 MW CT;
    - 96 MW combined heat and power plant using a CC; and
    - 122 MW conversion of Hoot Lake units 2 and 3 from coal to gas.
- OTP considered the following renewable energy resources:
    - 1 MW utility-scale photovoltaic (PV) resource; and
    - 50 MW utility-scale wind resource.
- OTP considered the following demand-side resources:
    - energy savings equaling approximately 1.5 percent of retail sales;
    - 15 MW of additional load control by 2028.
- OTP ran its Strategist software, a capacity expansion model, and set the model to choose the least-cost mixture of supply-side and demand-side resources for meeting the Company's resource needs. OTP set the model to minimize costs with and without environmental costs. OTP called the resulting expansion plan the Company's Preferred Plan. Otter Tail also modeled many different scenarios, varying the value of different inputs.

C. OTP's CAPACITY RESOURCE NEEDS

The purpose of integrated resource planning is to assist an electric utility in determining reasonable size, type and timing of future demand- and supply-side resources. Because the options and factors are numerous and inter-related, utilities like Otter Tail use capacity expansion models that are designed to help inform these decisions. To estimate how much additional capacity is needed over the planning period, utilities estimate annual load along with their capability to meet that load; if the utility does not have sufficient resources, they must propose a plan to add resources. Where it is necessary to add resources, capacity expansion models provide critical information about least-cost plans to ensure that utilities provide reliable service at reasonable costs (including relevant externality costs) under a variety of future scenarios. Expansion plans are robust if they are optimal under numerous scenarios.

Otter Tail will need to add resources over the planning horizon. The Company presents its Projected Base Case Load and Capability Prior to Resource Plan Information in Table 2-1 on page 2-2 of its IRP. Otter Tail's project capacity surplus (deficit) is shown in Table 1 below:

Table 1: OTP's Projected Summer Capacity Surplus/(Deficit)

Year	OTP Projected Capacity Surplus/(Deficit) (MW)
2014	136
2015	113
2016	94
2017	15
2018	7
2019	12
2020	3
2021	(189)
2022	(204)
2023	(212)
2024	(221)
2025	(230)
2026	(233)
2027	(242)
2028	(251)

D. OTP'S PREFERRED PLAN

OTP states that its preferred resource plan is the least cost plan developed by the Strategist model without the consideration of environmental externalities, CO_2 values, or other proposed environmental regulation and using base case assumptions for load growth, fuel prices (natural gas and coal), solar, wind, market energy prices, capacity prices, and capital costs. OTP's Preferred Plan consists of adding 211 MW of a natural gas combustion turbine in 2021, achieving annual first year energy savings from demand side management (DSM) of approximately 1.5 percent of retail sales in Minnesota and additional energy savings in South Dakota (total of approximately 91 MW of capacity savings) and total additional demand response resources of 56 MW. Otter Tail did not include any solar additions in its preferred plan.

On page 2-6 of its IRP, OTP shows how the energy mix (fuel source) for the Company is expected to change between 2012 and 2028. The Department shows the changes in Table 2 below.

Table 2: Otter Tail's Present and Future Mix of Fuels for Producing Energy

Fuel Source	2012	2028
Coal	64%	56%
Natural Gas	1%	10%
Wind/Hydro	15%	16%
Purchases	20%	18%

II. DEPARTMENT ANALYSIS

A. OVERVIEW OF ANALYSIS

Minnesota Statutes §216B.2422, subd. 4 states:

> The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243 … unless the utility has demonstrated that a renewable energy facility is not in the public interest.

The Department conducted its review of OTP's IRP noting that the analysis in the IRP would have material bearing on OTP's future regulatory proceedings. Given OTP's need for a significant amount of new resources during the planning period, the Department's comments are aimed at preparing for future Certificate of Need (CN) proceedings and identifying least-cost resources to meet those resource needs.

For this IRP, the Department reviewed OTP's:

- energy and demand forecast,
- resource needs,
- demand-side resources,
- modeling,
- renewable energy standard (RES) requirements,
- environmental regulations, and
- greenhouse gas reduction goal.

Based on this analysis the Department reached the following conclusions:

- OTP should reply to the Department's questions about the Company's sales forecast;
- OTP should strive for an energy savings goal of approximately 1.7 percent of retail sales;

- OTP's proposed expansion plan should be modified to include more wind resources and comply with Minnesota's Solar Energy Standard;
- OTP is in compliance with its 2013 RES obligations;
- OTP is adequately tracking environmental regulations that might impact its operations; and
- OTP should update its analysis of compliance with the Minnesota greenhouse gas reduction goal once the Commission approves a specific accounting method.

B. ASSESSMENT OF ENERGY AND PEAK DEMAND FORECASTS

1. Forecast Summary

As discussed in greater detail throughout this section, Otter Tail conducted long-run forecasts of energy requirements and peak demand (both winter and summer) over the period from 2013 to 2028 as part of its IRP filing. These models were relatively similar to those used in previous IRP filings, and the Department reviewed the models and results for reasonableness. During this review, the Department observed potential model specification issues and subsequently corrected these issues; however, after correcting these specification concerns, the results, for both energy requirements and peak demand, appeared to be too low compared to historical Otter Tail system growth. The results produced by the Company and the Department are generally within the same forecasting band; therefore, the forecasting difference between the models are not significant. The modeling concerns are important and the Department will work with Otter Tail to resolve these issues prior to future regulatory filings.

The Company also conducted an analysis of Otter Tail's demand on a MISO coincident peak. This analysis is necessary given a recent change in MISO's planning construct on a system aggregate peak. The Department reviewed this analysis and observed serious issues in the analysis that need to be addressed in *Reply Comments*.

2. Overview

Otter Tail used econometric forecasting models similar to those used in previous IRP filings to conduct its energy sales and demand forecasts. Specifically, Otter Tail uses Ordinary Least Squares (OLS) regression techniques to conduct its forecasting process. The Company developed its monthly energy sales models for each customer class, by jurisdiction, as a function of historical monthly use per customer, monthly dummy variables, weather (both heating degree days and cooling degree days), and economic data. Since Otter Tail estimates use per customer models, it is also necessary to produce customer count models. The Company developed its customer count models as a function of monthly dummy variables and economic data. Otter Tail then multiplied the estimated customer counts by estimated use per customer to arrive at monthly energy sales. Then Otter Tail summed the individual customer class forecasts to yield the total system sales forecast. Finally, Otter Tail applied a loss factor to convert MWh sales (before line losses) to MWh native energy requirements (including line losses).[2]

Otter Tail also uses OLS regression techniques to forecast its maximum monthly demand needs. The Company estimates its monthly demand needs as a function of monthly dummy variables, Gross Regional Product (GRP), and weather variables (cooling and heating degree days) weighted by appliance saturation.[3] The demand figures forecasted by Otter Tail in this model do not include information related to its pipeline customers and other large industrial customers. These pipeline and large industrial figures are estimated separately, based on communications with individual customers, and then added to the forecasted monthly demand numbers to arrive at the total monthly demand numbers. Otter Tail's annual peak demand represents the greatest monthly demand number in a given year.

Otter Tail also uses the results from its energy sales and demand forecasts to construct two alternative scenarios, a low-growth and a high-growth scenario. For both the energy sales forecast and the demand forecast, the alternative scenarios are based on the confidence intervals created by the regression forecast. Since forecasting involves uncertainty, the forecast creates confidence intervals between which the most likely result (*e.g.,* base case) occurs and then any other results that would be a statistically reasonable outcome given the forecast. The low-growth and high-growth scenarios presented by Otter Tail in its filing represent the upper and lower thresholds of its forecasting confidence intervals, or, in other words, the maximum or minimum statistically significant forecasting results.

3. Otter Tail's Energy Forecast

Over the IRP planning period (2013-2028), Otter Tail projects an increase in energy requirements of approximately 1.49 percent per year for its base case. This growth rate is approximately 0.17 percent lower than the 1.66 percent growth rate forecasted by Otter Tail over the period 2010-2024 in its 2010 IRP filing. Otter Tail's projected system energy requirements are shown in Figure 1 below.

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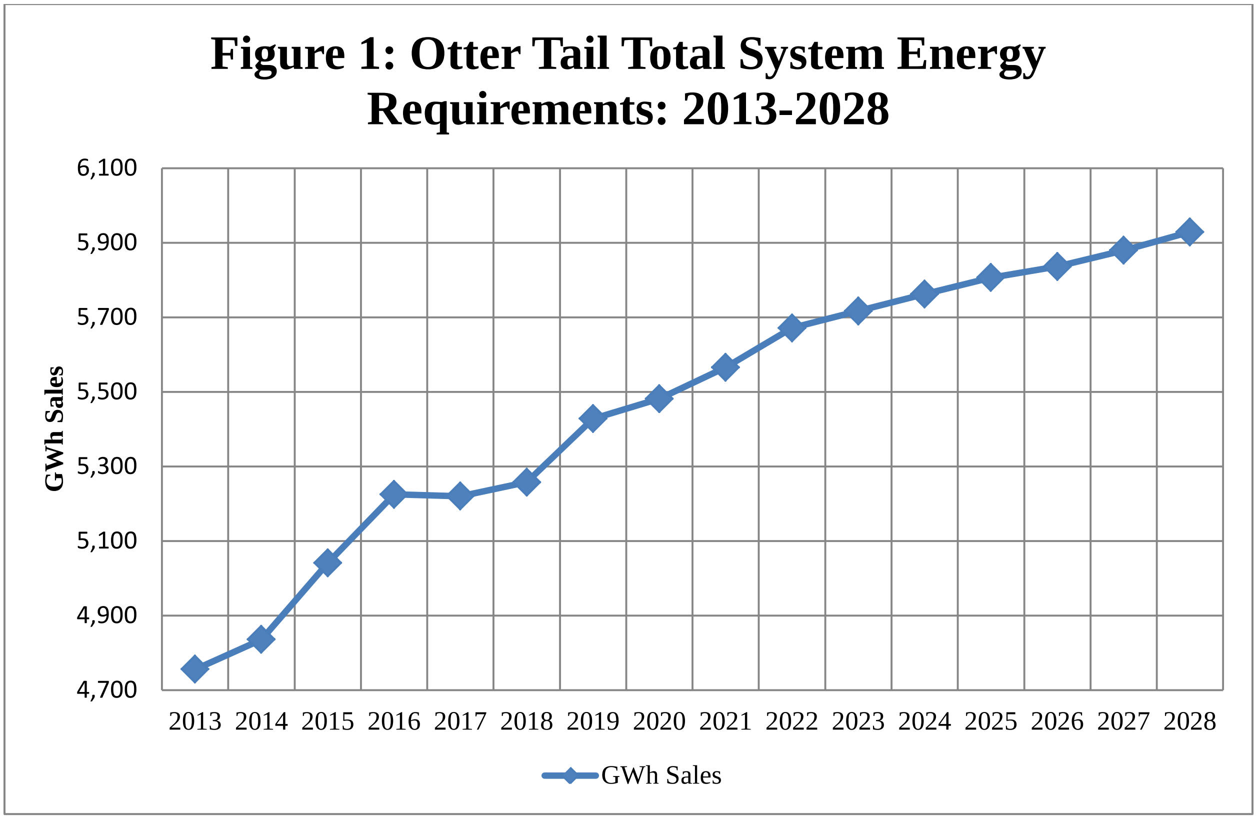
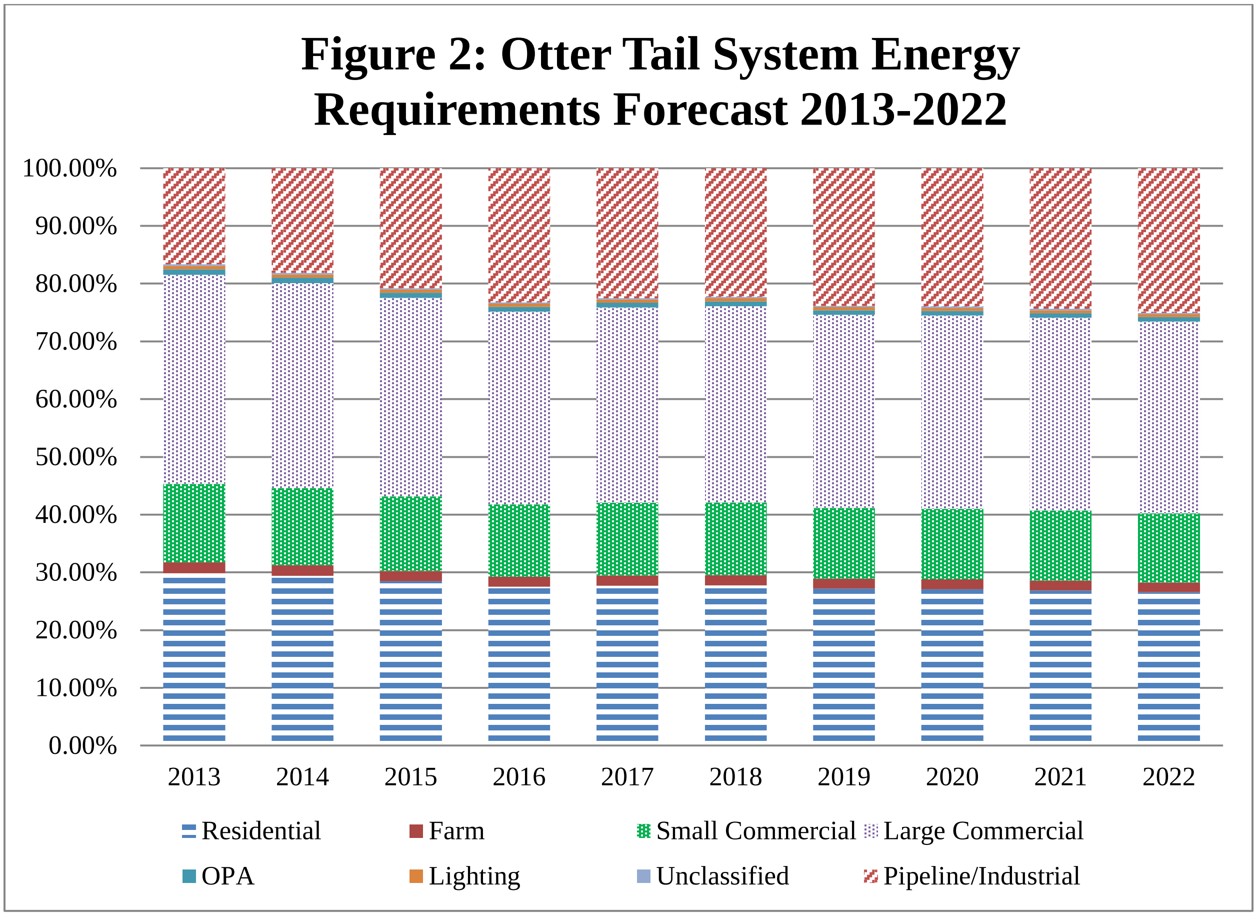
2 Otter Tail assumes a seven percent line loss factor. The Department notes that this line loss factor does not match the 11 percent Transmission and Distribution factor referenced by the Company on Page 67 of Appendix B in its *Petition*. The Department recommends that Otter Tail fully explain this difference in its *Reply Comments* and identify which line loss factor is the correct figure to use in this proceeding.

3 The total household and GDP determinants are based on information from Woods and Poole, which is an economics company that specializes in the collection of local area demographic and economic data.



In terms of the distribution of sales across customer classes, Otter Tail's system, based on the energy sales forecasts, expects a slight shift in sales from the Residential (decrease in proportional consumption) to Pipeline customer class (increase in proportional consumption), which was also forecasted in the previous IRP filing. This expected shift in sales is the result of increases in demand by pipeline customers over the next decade in response to growing Canadian and domestic oil production and increased demand for shipment of oil via pipeline through Minnesota. This increase in pipeline demand is also the likely cause for the steady increase in energy sales through 2016, as illustrated in Figure 1 above.

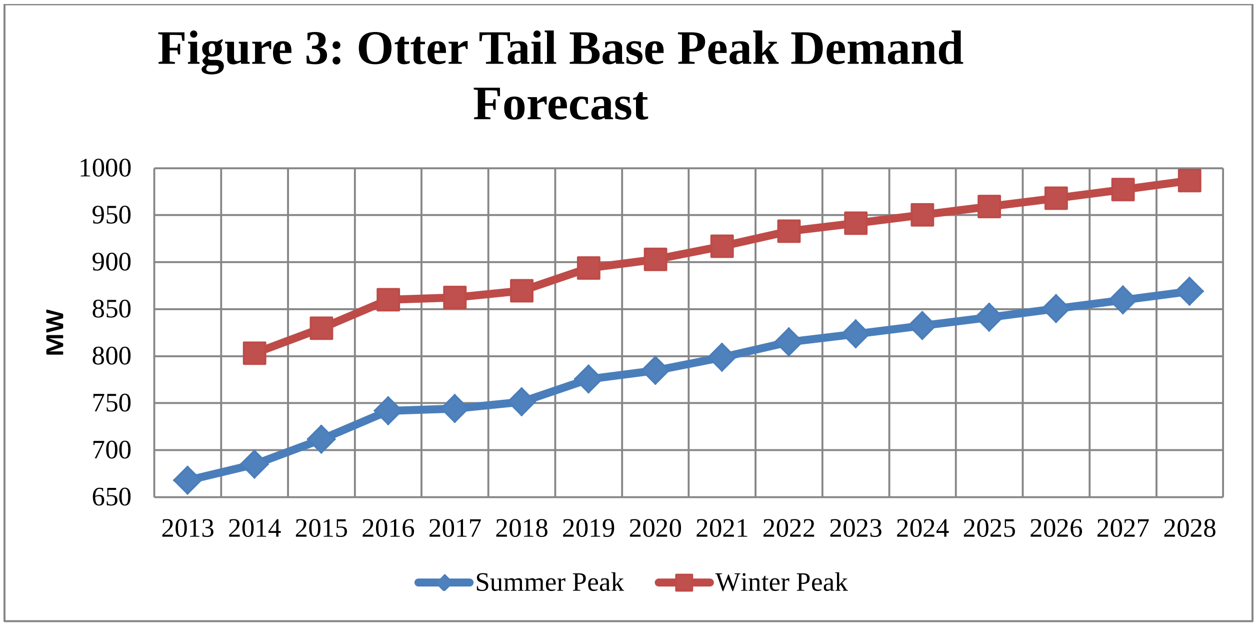
Over the period 2013-2022, as pipeline demand increases, Otter Tail projects that sales to the Residential customer class will decrease from roughly 30 percent of total system sales to approximately 27 percent. The Company projects that sales to the Pipeline customer class will increase from just under 17 percent of sales in 2013 to just over 25 percent of total system sales in 2022. Otter Tail also projects a decrease in proportional sales to the Large Commercial class; specifically, the Company projects that sales to the Large Commercial class will decline from just over 36 percent of Otter Tail's retail customers in 2013 to just over 33 percent in 2022. The proportions of sales to the remaining rate classes over the next ten years is projected to remain roughly the same. This information is presented in Figure 2 below.



4. *Otter Tail's Peak-Load Forecasts*

As noted above, Otter Tail used an OLS regression analysis and estimates of pipeline peak demand to forecast system peak demand. Through its analysis, the Company estimated both a summer peak demand and a winter peak demand.[4] Based on its analysis, Otter Tail projects a 1.78 percent summer peak demand growth rate and a 1.48 percent winter peak demand growth rate over the planning period (2013-2028) for its base case, a 1.91 percent summer peak demand growth rate and a 1.57 percent winter peak demand growth rate over the planning period for its high-growth case, and a 1.67 percent summer peak demand growth rate and a 1.41 percent winter peak demand growth rate over the planning period for its low-growth case. These forecast results suggest that Otter Tail's peak demand growth is not significantly influenced by different usage scenarios (*i.e.*, base case, high-growth, low-growth). Otter Tail's peak demand forecasts are presented in Figure 3 below.

[4] Historically, Otter Tail has determined its summer peak over the months May through October and its winter peak over the months November through April.



5. IRP Input Data

In its testimony in Otter Tail's most recent rate case, Docket No. E017/GR-10-239, the Department noted that the Company used two sets of sales data in its rate case preparation. Specifically, Otter Tail used one type of customer billing data to calculate its test-year revenue (CIS/A) and another type of customer billing data to determine its weather normalization and unbilled revenue calculations (CIS339). The difference between the two sets of customer data is that the CIS/A data corrects for billing errors in the month when the error occurred while the CIS339 data corrects for billing errors in the month the error was discovered. In the Company's last IRP filing, the Department determined that Otter Tail used CIS339 input data in that filing. In its recommendations in the IRP filing, the Department recommended that Otter Tail choose a single dataset in the future and maintain this across all associated regulatory filings (*i.e.*, rate case, IRP, certificates of need).

The Department reviewed Otter Tail's input data in this IRP filing and concludes that the Company used CIS/A data in its analysis. These data are slightly different than the CIS339 data that has been used in previous filings; however, given how the CIS/A data are corrected, the Department believes that this data stream will produce more appropriate results in the future.

6. Forecasting Concerns

The Department identified two variables that require additional clarification from the Company. First, the Company bases its heating degree day (HDD) variable on base 55 HDD data. HDDs are designed to measure heating load and the average temperature at which heating load begins. In the case of a base 55 dataset, the assumption is that heating load begins at a daily average temperature of 55°F. There is no single HDD standard, and the HDD base used in an analysis can affect the impact that weather may have on heating load. The Department does not necessarily take issue with the use of base 55 HDD data; however, it is important to note that utilities (both electric and natural gas) generally use base 65 HDD in their estimates of energy consumption. As such, the Department recommends that Otter Tail fully explain, and justify, in *Reply Comments* why it uses base 55 HDD data in its IRP analysis instead of the more commonly used base 65 HDD data.

Second, the Department observed that the Company used weather interaction terms in several of its use per customer models. The specification created by Otter Tail assumes an exogenous change in the impact of weather beginning in a given calendar year. On its own, the use of an interaction term is not an issue because the variable attempts to model a change in the relationship between a given independent variable (*e.g.,* weather) and the dependent variable (*e.g.,* energy consumption). The issue in this case is that the variable specification creates two independent variables that have the same data for parts of the historical period and the entire forecasting period. Using the same data in the two variables is likely to create correlation between the two variables (*e.g.,* HDD55 and HDD55*Calendar Year 2012 going forward), which may impair the estimative power and overall stability of the models. Given these potential concerns, the Department recommends that Otter Tail provide the following in *Reply Comments* regarding its weather interaction terms:

- A full explanation of what steps and analysis the Company conducted to verify that the weather interaction term did not impair the estimative power and stability of regression models; and
- A detailed explanation, including data if available, which supports a change in weather, or weather's impact on energy consumption, as suggested by the specification of the Company's weather interaction variables.

7. MISO Coincident Peak Coordination

Beginning in June 2013, MISO revised its resource adequacy construct. Specifically, MISO changed its peak demand construct from a monthly construct based on a non-coincident peak demand (*i.e.,* based on individual load-serving entity's peak demand) to an annual construct based on MISO's coincident peak demand (*i.e.,* total aggregate demand for the entire MISO footprint on the day that MISO's system has the highest load). Traditionally, the Department evaluated a utility's resource plan to ensure that the utility had adequate resources to cover its individual 50/50 system capacity forecast. Since the individual utility's system demand can vary from MISO's coincident peak demand, MISO refers to the individual utility's peak demand as its non-coincident peak (NCP) within MISO. A second approach for determining an individual utility's peak demand estimates the individual utility's peak demand at the time of MISO's coincident peak. MISO refers to this approach as the coincident peak (CP) method.

MISO is responsible for maintaining the reliability of the bulk transmission system, but states are responsible for ensuring that utilities within their jurisdiction have adequate generation and demand-response resources. Thus, given this recent change in MISO's policies regarding transmission, it is important to assess whether state resource planning should be changed to reflect MISO's policy. Although the CP method has merit because it takes into account changes in how MISO views capacity, the Department believes that the Commission should approve resource plans that ensure that each utility has a reliable system. A planning protocol that assumes an individual utility will only be responsible for its portion of MISO's CP could result in that same utility having inadequate generation resources in the event that one or more of MISO's planning assumptions are violated.

As discussed earlier, Otter Tail forecasts its peak demand in the IRP planning period based on historical month peak demand data for the Company's system; therefore, this peak demand forecast does not match with MISO's new planning construct but does reflect the method the Commission has used.

For MISO's new construct, the Company estimates expected load on Otter Tail's system during a MISO peak day by using a two-stage linear regression analysis, based on historical data from the Otter Tail system, and further calculations. Otter Tail uses monthly summer month peak demand data, weather data, and the diversity factor, both on the OTP system peak and MISO coincident peak, from 2005 to 2011 to estimate Otter Tail's demand on MISO's peak. The first stage involves using the absolute difference between the MISO peak weather and OTP system peak weather to estimate the Company's diversity factor with MISO's peak day.[5] The second stage involves using weather data on Otter Tail's peak to estimate weather on the MISO coincident peak.

The Company forecasted coincident peak weather by finding the difference between 20-year normal OTP non-coincident peak weather in July and estimated MISO coincident peak weather based on the results of the weather regression. The Company calculated a difference of just under 2 degrees on the Temperature-Humidity Index between Otter Tail's system peak and Otter Tail system weather on the MISO coincident peak. Otter Tail then completed its analysis by estimating its forecasting period diversity factor. Otter Tail calculated the diversity factor by multiplying the weather coefficient from the diversity factor regression by the forecasted difference in coincident peak and non-coincident peak weather and then adding the base diversity factor from the diversity factor regression. The result of this analysis is an estimated MISO peak day diversity factor for Otter Tail of approximately 8.9 percent. This factor is also included in the Company's expansion plan modeling.

While it is understandable that Otter Tail attempted to design its system under MISO's policies, it is also important to examine what Otter Tail's resource needs are based on demand on Otter Tail's system, regardless of when MISO's system peaks. The Department discusses this issue further below in assessing Otter Tail's resource needs.

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[5] Otter Tail defines weather as the Temperature-Humidity Index, which is created using a weighted average of weather stations across its service territory.

Beyond questions about whether Otter Tail should plan its resource needs around the Company's peak or MISO's peak, the Department has concerns regarding the method Otter Tail used to estimate the MISO coincident peak. First, the use of strictly July peak data to calculate the normal non-coincident peak weather data is not necessarily representative of past conditions.

For example, the Otter Tail system's non-coincident summer peak occurred in August 2005 and August 2012; as such, it is more appropriate to base the 20-year normal calculation on peak data regardless of the month it occurred. Second, the coincident peak analysis only uses data through 2011. The Department notes that Otter Tail filed its IRP on October 30, 2013, and it is unclear why data from 2012 or 2013 would not have been available to incorporate into the Company's calculations. Therefore, the Department recommends that Otter Tail provide, in its *Reply Comments*, its coincident peak analysis originally provided in its response to DOC Information Request No. 4 updated with 2012 and 2013 data.

Third, the coincident peak weather calculation, based on the second regression equation, is theoretically flawed. The calculation is flawed because the model attempts to estimate one set of weather data using another set of weather data. In simple terms, the Temperature-Humidity Index on one day does not cause the Temperature-Humidity Index on another day. The regression results may appear reasonable, and produce an acceptable diversity factor calculation, but there is no guarantee that reasonable or acceptable results will be produced on a consistent basis, and the Department is concerned that the current approach could create issues in the future.

As noted earlier in this section, estimating Otter Tail's demand on its system based on a MISO coincident peak is related to a change in MISO's peak demand planning requirements. Based on conversations with the Company, it appears that Otter Tail estimated its system demand on a MISO coincident peak based on a methodology suggested by MISO.[6] Given the issues with this methodology discussed above, the long-term reliability of this method is questionable. Further, it is possible that different, more theoretically and practically sound, methods exist to estimate the Company's load on a MISO coincident peak. One such example uses a method similar to Otter Tail's non-coincident peak forecast in this IRP filing but based on data representative of the MISO coincident peak. The limiting factor is that insufficient data currently exists to complete this analysis because MISO specific data does not exist prior to 2005; however, the Department believes creation of a representative historical MISO data stream is possible.

Assuming a reasonable level of data retention by all MISO members, there should be sufficient historical, daily (or even hourly) data available to calculate a representative historical daily MISO system demand figures. This representative data stream would be constructed by aggregating historical load data and then finding the monthly dates with the greatest demand. With data in this format, Otter Tail would be able to forecast peak demand in the same manner that it forecasted non-coincident peak in its IRP filing, with only minor changes to its weather data to correspond with the representative, historical MISO peak days. The Department

[6] The Department requests that Otter Tail confirm this understanding in its Reply Comments.

recommends that Otter Tail provide a detailed discussion in its *Reply Comments* regarding whether it believes creation of a dataset representative of historical MISO conditions is possible, from Otter Tail's perspective, and whether the Company would be amenable to participating in this type of analysis with MISO.

8. Deployment of Demand Response

As noted in the Company's initial filing, Otter Tail has registered its load management system and retail firm service level contracts under Module E as demand resources. This decision means that demand response and load management controls are dispatched by MISO and not by Otter Tail. The Company stated in its filing that it successfully registered 30 MW of demand resources with MISO.

Otter Tail's decision to allow MISO control of load management raises potential concerns regarding the availability of load management on an Otter Tail system peak, either in the summer or winter. In particular, the arrangement raises the possibility that the Company's full allotment of accredited demand resources might not be available on an Otter Tail system peak. The Department reviewed the Company's discussion of this topic and was unable to find data detailing the amount of demand response available on a non-coincident peak. Given the lack of supporting data and discussion, the Department recommends that Otter Tail provide the following in *Reply Comments*:

- A detailed discussion of how MISO dispatches demand response and what, if any, say Otter Tail has on the deployment of these resources on a non-coincident, either summer or winter;
- Otter Tail's historical demand response deployment, by day, over the period since Otter Tail registered load management with MISO;
- Otter Tail's historical demand response deployment, by day, for five years before Otter Tail registered load management with MISO; and
- A detailed discussion of how much demand response Otter Tail believes MISO will have available, in the future, to account for the Company's non-coincident peak.

9. Forecasting Recommendations

Based on the Department's review of Otter Tail's energy sales and peak demand forecasts, modeling issues exist that need to be addressed. As such, the Department requests that the Company provide clarification identified below in its *Reply Comments*. Further, the Department reviewed Otter Tail's forecast of its projected demand on a MISO coincident peak. This IRP marks the first time that the Company has forecasted this value. It is important from a resource planning perspective to assess whether MISO's construct affects Minnesota's resource planning. Further, even if it were reasonable to plan resources based on MISO's peak rather than Otter Tail's peak, based on its review of Otter Tail's projection method, the Department identified issues with Otter Tail's method of estimating load on its system during MISO's peak. Given the various forecasting issues discussed above, the Department requests further information in Otter Tail's *Reply Comments*:

- A full explanation of the difference in line loss factors in this proceeding (the 7 percent used in the forecasting analysis and the 11 percent factor referenced in Appendix B) and identify which line loss factor is the correct figure to use in this proceeding;
- A full explanation, and justification of why the Company uses base 55 HDD data in its IRP analysis instead of the more commonly used base 65 HDD data;
- A full explanation of what steps, and analysis, the Company conducted to verify that the weather interaction term did not impair the estimative power and stability of regression models;
- A detailed explanation, including data if available, which supports a change in weather, or weather's impact on energy consumption, as suggested by the specification of the Company's weather interaction variables;
- Clarification of whether the Company's method to estimate coincident peak is based on recommendations, or suggestions, from MISO;
- Otter Tail's coincident peak analysis originally provided in its response to DOC Information Request No. 4 updated with 2012 and 2013 data;
- A detailed discussion regarding whether the Company believes creation of a dataset representative of historical MISO conditions is possible, from Otter Tail's perspective, and whether the Company would be amenable to participating in this type of analysis with MISO;
- A detailed discussion of how MISO dispatches demand response and what, if any, say Otter Tail has on the deployment of these resources on a non-coincident, either summer or winter;
- Historical demand response deployment, by day, over the period since Otter Tail registered load management with MISO;
- Otter Tail's historical demand response deployment, by day, for five years before Otter Tail registered load management with MISO; and
- A detailed discussion of how much demand response Otter Tail believes MISO will have available, in the future, to account for the Company's non-coincident peak.

While Otter Tail's forecast may be reasonable, the information above is important to assess the Company's energy requirements, peak demand, and MISO coincident peak forecast. The Department will provide its recommendations subsequent to reviewing the information above.

C. RESOURCE NEEDS

OTP's resource needs as expressed in the Company's Load and Generation Capacity Report (which MISO calls the NCP) are shown in Table 3 below. As noted above, the Company estimated its resource needs by planning for the MISO Coincident Peak (CP).

Table 3: Otter Tail's Resource Needs Assuming MISO CP and NCP

Year	OTP's Capacity Surplus/(Deficit) Based on MISO CP (MW)	OTP's Capacity Surplus/(Deficit) Based on NCP (MW)	Difference between NCP and CP (MW)	Increase in Resource Needs Under NCP (MW)
2014	136	81	55	-
2015	113	57	56	-
2016	94	37	57	-
2017	15	(43.1)	58.1	43.1
2018	7	(51.2)	58.2	51.2
2019	12	(46.9)	58.9	46.9
2020	3	(56.7)	59.7	56.7
2021	(189)	(249.3)	60.3	60.3
2022	(204)	(265.3)	61.3	61.3
2023	(212)	(274.5)	62.5	62.5
2024	(221)	(283.9)	62.9	62.9
2025	(230)	(293.3)	63.3	63.3
2026	(233)	(297.4)	64.4	64.4
2027	(242)	(307.2)	65.2	65.2
2028	(251)	(317.2)	66.2	66.2

Beginning 2021, under MISO's new construct, Otter Tail projects a capacity need of 189 MW that grows to 251 MW in 2028. The jump in resource needs is due to the retirement of the Hoot Lake Plant and the expiration of some power purchase agreements. However, the Department also shows in Table the Company's resource needs if the Company plans for the Company's system peak rather than its peak coincident with MISO's peak under MISO's method. As can be seen, under the assumption of planning for the NCP, Otter Tail experiences a deficit in 2017, instead of 2021, and by 2028 the resource need is 66 MW higher. The Department further discusses the issue of CP vs. NCP in the Modeling section below.

D. DEMAND-SIDE MANAGEMENT

1. Introduction

One purpose of resource planning is to estimate the optimal amount of demand-side resources for meeting the Company's customer future needs. In the past, another factor used to assess the amount of DSM in a resource plan was whether it at least included the amount of energy and demand savings that would result from meeting the statutory spending requirements of the Conservation Improvement Program (CIP). The CIP statutes (Minn. Stat. §216B.2421) were changed in 2007; the statute now sets an annual energy savings goal of 1.5 percent of gross annual retail sales for each utility unless adjusted by the Commissioner.

In addition, Minn. Stat. 216B.2401 states:

> The legislature finds that energy savings are an energy resource, and that cost-effective energy savings are preferred over all other energy resources. The legislature further finds that cost-effective energy savings should be procured systematically and aggressively in order to reduce utility costs for businesses and residents, improve the competitiveness and profitability of businesses, create more energy-related jobs, reduce the economic burden of fuel imports, and reduce pollution and emissions that cause climate change.
>
> Therefore, it is the energy policy of the state of Minnesota to achieve annual energy savings equal to at least 1.5 percent of annual retail energy sales of electricity and natural gas through cost-effective energy conservation improvement programs and rate design, energy efficiency achieved by energy consumers without direct utility involvement, energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.

In the Commission's Order accepting OTP's 2010 IRP, the Commission approved a 1.2 percent annual energy savings target for resource planning purposes.

2. Historical Performance

Since the creation of an energy savings goal through the 2007 Next Generation Energy Act, OTP's annual energy savings as a percent of total retail sales has increased significantly. From 2009 to 2013, OTP averaged annual energy savings of 1.46 percent of total retail sales. OTP's historical DSM conservation savings are listed in Table 4 below. Table 4 data comes from the Energy Savings Platform (ESP™), the online platform in which Minnesota utilities report their CIP achievements.

Table 4: Otter Tail Power's Historical CIP Achievements and Costs

Year	CIP Expenditures	Annual Credited Savings (MWh)[7]	Annual Savings Cost ($/kWh)	Percent Savings	Lifetime savings (MWh)	Lifetime Energy Cost ($/kWh)
2009	$4,093,050	33,028	$0.12	1.60%	444,052	$0.009
2010	$5,043,317	30,626	$0.17	1.50%	370,117	$0.014
2011	$4,344,576	25,861	$0.17	1.20%	305,746	$0.014
2012	$4,816,995	28,484	$0.17	1.30%	319,928	$0.015
2013	$5,253,935	35,792	$0.15	1.70%	435,075	$0.012
Average	**$4,710,375**	**30,758**	**$0.16**	**1.46%**	**374,984**	**$0.013**

In OTP's 2010 IRP the Company assumed a 15-year average conservation lifespan for modeling purposes. The Department used the 15-year average lifespan assumption in its analysis below.

3. *Otter Tail's 2014 – 2016 Triennial CIP*

On May 31, 2013, the Company filed its 2014 – 2016 Triennial CIP filing (Triennial). The Triennial includes the Company's conservation goals for the upcoming three years; these energy savings are listed in Table 5 below. The Triennial was approved in the Department's Deputy Commissioner Decision on October 10, 2013.

Table 5: 2014 – 2016 Otter Tail Triennial CIP Goals

Year	Proposed Energy Savings (MWh)	Percent of Average Adjusted Retail Sales
2014	31,405	1.50%
2015	31,762	1.52%
2016	32,476	1.55%

4. *DSM in Current IRP*

In its current IRP Otter Tail stated that it included annual energy savings of 1.5 percent of sales in its base case plan. In response to Department IR 2 the Company provided a yearly breakdown of conservation assumed in the base plan. The Department analyzed the assumed conservation levels and costs using average conservation lifespan data from the Company's historical conservation achievements. The Department's analysis below assumes that the Company's conservation costs increase by the same three percent inflation rate used in other parts of the Company's IRP. The analysis results are included in Table 6 below.

[7] Annual savings at the meter.

Table 6: Otter Tail Power's IRP Conservation Levels and Costs

Year	Otter Tail Power Data				Department Analysis Using Otter Tail Power Data			
	Cumulative Conservation (GWh at the meter)	1st year Conservation (GWh at the meter)	Conservation % of average 3 year sales	Conservation Costs Assumption ($000)	1st Year Conservation Costs per kWh (nominal)	First Year Conservation Costs per kWh ($ 2013)	Estimated Lifespan Conservation Costs per kWh (nominal)	Estimated Lifespan Conservation Costs per kWh ($ 2013)
2014	29	29.2		$5,492	$0.19	$0.18	$0.016	$0.012
2015	59	29.5		$5,557	$0.19	$0.18	$0.016	$0.012
2016	89	30.2		$5,672	$0.19	$0.17	$0.016	$0.011
2017	124	35.3	1.50%	$6,831	$0.19	$0.17	$0.016	$0.011
2018	161	36.4	1.50%	$7,264	$0.20	$0.17	$0.016	$0.011
2019	197	36.8	1.50%	$7,551	$0.21	$0.17	$0.017	$0.011
2020	234	36.9	1.50%	$7,812	$0.21	$0.17	$0.017	$0.011
2021	272	37.3	1.50%	$8,136	$0.22	$0.17	$0.018	$0.011
2022	310	38.0	1.50%	$8,521	$0.22	$0.17	$0.019	$0.011
2023	348	38.3	1.50%	$8,851	$0.23	$0.17	$0.019	$0.011
2024	386	38.6	1.50%	$9,184	$0.24	$0.17	$0.020	$0.011
2025	425	38.7	1.50%	$9,484	$0.25	$0.17	$0.020	$0.011
2026	464	38.5	1.50%	$9,724	$0.25	$0.17	$0.021	$0.011
2027	502	38.3	1.50%	$9,972	$0.26	$0.17	$0.022	$0.011
2028	540	38.2	1.50%	$10,229	$0.27	$0.17	$0.022	$0.011

Based on the data provided by the Company in Table 6, the Department concludes that the Company's assumed conservation costs are consistent with its historical savings cost experience. As part of its DSM analysis the Department used Strategist to evaluate a higher, 1.7 percent, energy savings level; this energy savings level is an additional 0.2 percent of annual energy savings beyond Otter Tail's base case of 1.5 percent annual energy savings. The change in the present value of social costs with the incremental increase in conservation represents the avoided cost these programs could bring to Otter Tail's ratepayers. To be cost neutral (i.e., the total social costs of the expansion plan would neither be greater nor lesser than the least-cost plan assuming embedded energy conservation) the net present value of the cost to achieve the additional 0.2 percent of energy savings would need to be less than or equal to the net present value of the avoided power supply costs.

The net present value difference over the 15-year planning period between the base case and the incremental 0.2 percent energy savings scenario is $19,249,000. In other words, the scenario with 1.7 percent energy savings is projected to produce an additional $19 million of avoided costs over the planning period. Savings from additional conservation beyond the 15-year planning period are not included in the net present value difference. The annual value of power supply costs avoided with incremental 0.2 percent conservation is $2,318,000 in 2013 dollars.[8] Therefore, an additional 0.2 percent annual energy savings could be cost effective if the total cost to achieve those first year incremental savings is below $2,318,000 for each year of the planning period, or below $19.2 million over the planning period. Table 7 below shows the 0.2 percent incremental conservation budget for each year in the planning period. The average budget, incremental conservation, and costs per kWh are listed in the last row.

[8] The annual power supply costs were calculated using the total cost savings of $19,249,000 over 15 years and the Company's discount rate of 8.5%.

Table 7: 0.2 Percent Incremental Conservation Budget, Savings, and Costs

	Strategist Outputs		Budget for Additional Conservation	
Year	Average Annual Value of Avoided Cost with Incremental 0.2% Conservation (2013 dollars)	Annual 0.2% Incremental Conservation (GWh)	First Year Cost per kWh saved (2013 dollars)	Lifetime Cost per kWh saved (2013 dollars)
2014	$2,318,000	3.89	$0.60	$0.040
2015	$2,318,000	3.93	$0.59	$0.039
2016	$2,318,000	4.02	$0.58	$0.038
2017	$2,318,000	4.70	$0.49	$0.033
2018	$2,318,000	4.86	$0.48	$0.032
2019	$2,318,000	4.90	$0.47	$0.032
2020	$2,318,000	4.92	$0.47	$0.031
2021	$2,318,000	4.98	$0.47	$0.031
2022	$2,318,000	5.06	$0.46	$0.031
2023	$2,318,000	5.10	$0.45	$0.030
2024	$2,318,000	5.14	$0.45	$0.030
2025	$2,318,000	5.16	$0.45	$0.030
2026	$2,318,000	5.13	$0.45	$0.030
2027	$2,318,000	5.11	$0.45	$0.030
2028	$2,318,000	5.09	$0.46	$0.030
Average	**$2,318,000**	**4.80**	**$0.49**	**$0.033**

On average over the planning period the incremental first-year conservation budget per kWh is approximately 2.9 times the average cost of conservation in the Company's 1.5 percent conservation base case (see Table 6 for base case conservation cost assumptions; $0.49 is about 2.9 times higher than $0.17.). Though the marginal costs to achieve higher levels of conservation are thought to be higher than the average costs of conservation, in the absence of marginal cost data from the Company there is little reason to believe that the costs to achieve the higher levels of conservation are nearly three times higher than the average costs.

6. Department Recommendation

The Department recommends that the Commission approve a 1.7 percent annual energy savings target for resource planning purposes. The Department recommends this higher energy savings level for the following reasons:

1. Otter Tail achieved 1.7 percent energy savings in 2013. Their achievements in the last five years suggest that a 1.7 percent energy savings goal is achievable.
2. Otter Tail's historical lifetime conservation cost per kWh is significantly below the average energy cost of $0.04.
3. The cost difference between the Company's proposed DSM 1.5% annual energy savings goal and a 1.7 percent annual energy savings target demonstrate that the additional conservation is likely cost effective.

The Department notes that the Commission approved the Shared Savings DSM financial incentive mechanism, which encourages the Company to maximize its savings. The 0.2 percent additional DSM does not change the Department's preferred expansion path, (i.e., the supply-side resources needed do not change). Thus, the Commission could approve the higher energy savings amount without concern that OTP could face a reliability problem if the Company did not achieve the energy savings over the long term.

a. Maintenance Schedules

The Department made several minor changes to inputs related to maintenance schedules for Otter Tail's Big Stone, Coyote, and Solway Plants, using information provided in the Company's response to Information Request No. 17. Based on this response, the Department does not expect these minor changes to impact its modeling results.

b. Wind Availability

In its Strategist analysis, Otter Tail included wind as a resource alternative in the form of 50 MW power purchase agreements (PPA), with terms of 20 years, and an initial price of $45/MWh, increasing at a rate of three percent per year. The Company allowed Strategist to select up to ten wind PPAs every year beginning in 2015.

As noted above, the Department noticed a heavy reliance on the wholesale energy market in Otter Tail's preferred case. Specifically, in the Company's preferred case, market purchases fulfill approximately 16.5 percent of the Company's overall energy needs, ranging from a low of 10.0 percent in 2014 to a high of 24.7 percent in 2022. This heavy reliance on market purchases raises red flags in the Department's view, not only for the potential reliability issue noted above regarding the inadequacy of Otter Tail's generation units to meet the needs of its customers, but also that energy from the Company's existing generation fleet is expensive relative to the wholesale market (in other words, Strategist is selecting market purchases rather than dispatching Otter Tail's generating units because the market purchases are less expensive). Due to Otter Tail's heavy reliance on market energy, the Department made additional wind units available in Strategist as alternatives to supply energy through 2021.[9]

[9] Strategist labels these additional units as "superfluous" units.

If these additional wind units are not available for the model to choose, Strategist attempts to add new resources only if the system being modeled faces a capacity need. For example, in Otter Tail's preferred case, the Company does not face a capacity need until 2021. Because of this lack of capacity need, Strategist does not even attempt to add new generating units to the Company's system before 2021. By allowing more wind to be selected as an energy resource, Strategist tests the effects of adding the wind even in the absence of a capacity need, and ultimately selects the unit if its addition results in lower system costs. Allowing such units to be selected by the model will result in lower system costs if the units provide energy less expensively than the wholesale market, or other, existing units. It is possible that a new wind PPA, if priced low enough, could lower the overall cost of Otter Tail's system by displacing either more expensive market purchases or energy produced by one of Otter Tails' more expensive units. Thus, the Department made more wind available to Strategist through 2021.

Initially, allowing more wind to be selected caused Strategist to exceed the model's maximum of 5,000 states in many years. (In each year analyzed, Strategist creates a "state" for every viable expansion plan, and from one year to the next, Strategist can save a maximum of 5,000 states.) When this maximum is exceeded, Strategist ranks the states by cost, and discards the most expensive states until the limit of 5,000 saved states is reached. It is possible that the expansion plan that ranks 6,000th in the third year of a study period may end up as the least expensive plan over the full study period. By the end of the analysis, however, Strategist will already have discarded this plan, and thus users must be careful not to exceed the maximum number of states.

Thus, to reduce the number of states considered by Strategist, the Department modeled wind as a 20 year, fixed price, 100 MW PPA, and allowed only one unit to be selected every other year beginning in 2017. To set the fixed prices for the wind PPAs, the Department assumed a base price of $45/MWh in 2014, which then increased by three percent per year. In other words, the wind PPA available in 2017 was assumed to have a fixed price of $49.17/MWh (equal to $45/MWh with three years of inflation at three percent), the 2019 PPA was assumed to have a fixed price of $52.17/MWh, etc.. The Department notes that these assumed prices must account for all costs, including the costs of any new transmission, and the additional services imposed on Otter Tail's system by wind's lack of dispatchability.

Additionally, the Department set the hourly production profile of the generic wind alternative equal to the average hourly profile of Otter Tail's existing wind units. A small adjustment was made to the resulting production profile in order to set the capacity credit of the generic wind unit equal to 14.1 percent of the wind unit's nameplate capacity, which is the capacity accreditation used by MISO.

c. Solar

Otter Tail included in its analysis a solar resource alternative, modeled as a one MW PPA, and allowed Strategist to select up to 20 solar PPAs each year beginning in 2015.

Similar to wind, the Department allowed Strategist to select solar as a resource even in years in which there was not a capacity need. This approach, however, caused Strategist to exceed the maximum number of states it can save in many years. Thus, the Department allowed solar resources to be selected every other year beginning in 2016, and forced Strategist to test solar additions in 10 MW blocks (rather than 1 MW at a time).

Additionally, the Department notes that Otter Tail modeled solar as having capacity accreditation of 40 percent of nameplate capacity. The Department tested the effects of increasing solar's capacity accreditation to 60 percent of nameplate capacity and found that this change had very little impact on the frequency with which solar was selected by Strategist as a least-cost option. Therefore, the Department left solar's capacity accreditation at 60 percent of nameplate.

d. End Effects

The Department changed the consideration of end effects, which are the additional costs that occur beyond the 15-year period of the planning period; it is important to consider these effects. Otter Tail's Strategist modeling included infinite end effects, and as a result, end effects counted for roughly half of the total cost in any scenario modeled. While there is no right or wrong way to consider end effects, the Department prefers to use a shorter end effects period in order to avoid placing too much weight on costs to be incurred in the distant future due to the inherent uncertainty of those costs. Therefore, the Department limited the consideration of end effects to 15 years.

1. Scenarios Analyzed

a. Estimating Peak Demand

Three of the scenarios the Department analyzed focused on the effects of the new coincident peak reliability method implemented by MISO. As discussed above, the Department has some concerns with the method the Company used to forecast its coincident peak demand, and whether that method is capable of producing reasonable and consistent results. Until coincident peak can be forecasted more reliably, the Department is reluctant to rely on it for resource planning.

The Department has an additional concern related to the availability of demand response (DR) resources at the time of a utility's coincident peak. More specifically, the Department is concerned that DSM intended to reduce a utility's peak may not be available to the same extent at MISO's peak. For example, Otter Tail's summer non-coincident peak is likely to occur on a hot day on which a significant portion of its load is driven by air conditioners.[10] One of Otter

[10] Note that overall Otter Tail is a winter peaking utility; however Strategist was designed by the Company to use the summer peak for reliability purposes. Again, Otter Tail's approach is due to MISO's policies, which are targeted to the summer peak. Utilities have requested MISO to refine its method to examine seasonal peak.

Tail's DR resources is an air conditioning direct load control program which cycles participants' air conditioners on and off in order to reduce the Company's non-coincident peak load. However, it is possible that MISO's system peak will occur at a time when it is cooler in Otter Tail's service territory, and Otter Tail's customers may be running their air conditioners less, which would limit the load reduction made possible by the saver switch program.

In its response to Department Information Request No. 5, Otter Tail stated that it expects its DSM resources to be available at MISO's peak (the Company's coincident peak) at the level at which they are currently accredited. The Company stated that its direct load control systems (e.g. its air conditioning and water heating programs) are accredited based on actual and test controls that usually do not occur at the time of MISO's coincident peak or OTP's non-coincident peak. Therefore, the Company believes that the accredited values are already discounted in relation to their value at the time of Otter Tail's non-coincident peak. Because reliability is a critical issue, however, the Department remains concerned about the uncertainty surrounding the availability of Otter Tail's demand response resources.

In response to these uncertainties, the Department analyzed three scenarios to test the effects of three different reliability methods. The Department's Scenario 1 uses MISO's original non-coincident peak method (NCP method), in which MISO's 6.2 percent reserve margin is applied to Otter Tail's non-coincident summer peak. The Department's Scenario 2 uses MISO's coincident peak method (CP method), in which MISO's 6.2 percent reserve margin is applied to Otter Tail's estimate of its coincident peak.[11] The Department's Scenario 3 uses the CP method, but cuts in half the diversity factor that Otter Tail applies to its forecasted non-coincident peak to calculate its coincident peak. The Department will refer to this reliability method as the 50DF method (50% of Otter Tail's diversity factor). Figure 7 below shows the Company's surplus or deficit under different peak planning assumptions.

[11] The Department notes that Otter Tail implemented the coincident-peak method in Strategist by including a zero cost capacity resource equal in size to the reduction in capacity produced by its eight percent diversity factor. In order to model the non-coincident peak method, the Department simply removed this resource.

Figure 4: Otter Tail Power Capacity Surplus/(Deficit) 2014-2028

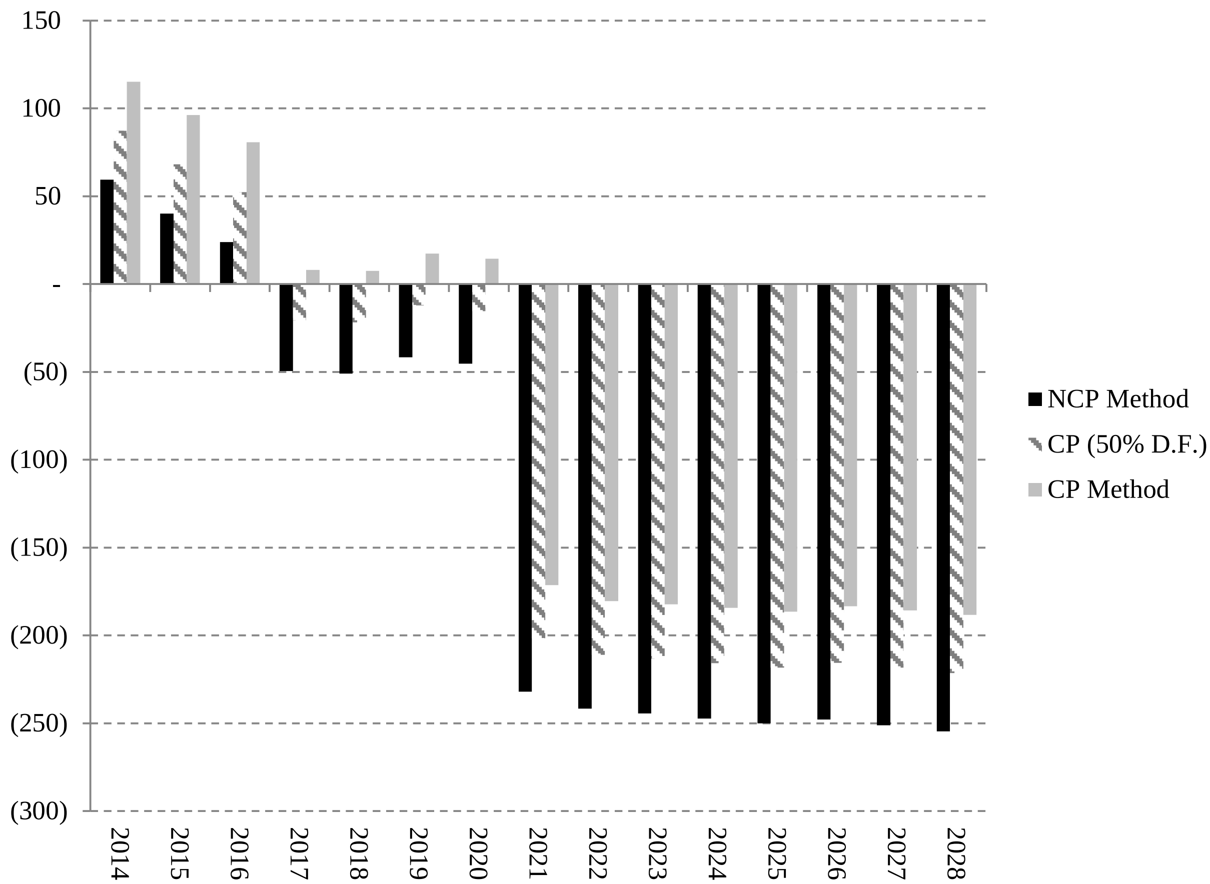

Figure 7 illustrates Otter Tail's net capacity position as calculated under the three reliability methods used by the Department, given the Company's existing resources (and planned retirements). The NCP method reduces Otter Tail's capacity position by roughly 55 MW each year, relative to the CP method. The NCP and 50DF methods both result in capacity deficits for Otter Tail in 2017, while the coincident peak method does not produce a capacity deficit until four years later, in 2021, when Hoot Lake Plant is scheduled to be taken out of service.

b. Other Scenarios

The Department's Scenario 4 is identical to Scenario 1, except that additional wind is not made available. The difference between scenarios 4 and 1 is the benefit/(cost) for not making wind available on an economic (as opposed to reliability) basis.

The Department's Scenario 5 is identical to Scenario 1, except that Otter Tail's three oil-fired peaking units are retired in 2022. The difference between scenarios 5 and 1 is the benefit/(cost) associated with retiring Otter Tail's oil-fired peaking units.

The Department's Scenario 6 is identical to Scenario 1, except that Otter Tail is allowed full access to the wholesale energy market throughout the entire study period. The difference between scenarios 6 and 1 is benefit/(cost) of building units rather than relying upon the wholesale market.

Additionally, the Department conducted more limited analyses of the impacts of the Solar Energy Standard (Minn. Stat. §216B.1691, subd. 2f) and Minnesota's Greenhouse Gas Emissions Control (Minn. Stat. §216H02, subd 1), discussed below.

c. Contingencies

For each of the six scenarios described above, the Department analyzed 37 contingencies in which the Department varied individual inputs. The contingencies are as follows:

1. Fuel prices, market energy prices, and load growth set equal to Otter Tail's base forecasts, with carbon cost set at $21.50/ton beginning in 2017 and high externality values for all other pollutants (the Department refers to this contingency as its base contingency);
2. Market energy prices 20 percent lower than Otter Tail's forecast, as well as 20 percent, 40 percent, and 60 percent higher;
3. High carbon cost ($34/ton) beginning in 2017 (with high externality values for the other pollutants);
4. Low carbon cost ($9/ton) beginning in 2017 (with low externality values for the other pollutants);
5. Mid carbon cost ($21.50/ton) beginning in 2019 (with high externality values for the other pollutants);
6. High carbon cost ($34/ton) beginning in 2019 (with high externality values for the other pollutants);
7. Low carbon cost ($9/ton) beginning in 2019 (with low externality values for the other pollutants);
8. Natural gas prices $1 lower than Otter Tail's forecast;
9. Natural gas prices increased at $1 increments from $1 to $5 above Otter Tail's forecast;
10. High load growth;[12]

[12] The Department notes that Strategist was unable to find a solution in the high load growth contingencies as Otter Tail is assumed to have a capacity need before it is able to build any new resources. Thus, as part of this contingency, the Department increased the amount of deferral capacity available to 50 MW per year, which solved this issue.

11. Low load growth;
12. Wind priced in $5 increments ranging from $30/MWh to $80/MWh;[13]
13. Solar priced at $133/MWh (Otter Tail's base price assumption), 21 MW of solar forced in 2019 to achieve 1.5 percent of Minnesota sales from solar in 2020 **(**per Minn. Stat. §216B.1691, subd. 2f, the Solar Energy Standard (SES));
14. Solar priced at $75/MWh (Otter Tail's low price assumption), with no solar forced into the model;
15. Solar priced at $75/MWh, with SES met;
16. Solar priced at $150/MWh (Otter Tail's high price assumption), with SES met; and
17. CO_2 emissions restricted per Minn. Stat. §216H02, subd 1.[14]

2. Strategist Results

Attachment 2 contains the present value of societal costs for the top ranked expansion plan from each of the 37 contingencies for all six scenarios (a total of 222 outcomes). Attachments 3-8 summarize the top ranked expansion plans for each contingency and each scenario.

a. Scenario 1

Attachment 2 summarizes the least-cost expansion plans (measured as the present value of societal costs) produced by each of the 37 contingencies run by the Department on its base Scenario, which used the non-coincident peak reliability method. The expansion plan produced by the Department's base contingency includes 100 MW wind PPAs in 2017, 2019, and 2021; a 200 MW gas combustion turbine (CT) in 2019, and 50 MW gas CT's in 2017 and 2024.

For comparison, the Department notes that Otter Tail's preferred plan, as shown on page 5-1 of its resource plan, includes only a 200 MW gas CT in 2021.

As noted above, the Department's use of the non-coincident peak reliability method pulls Otter Tail's capacity need forward in time from 2021 to 2017, and Strategist selects a 100 MW wind unit and a 50 MW gas CT to fulfill that need. The Department notes that these two additions in 2017 satisfy Otter Tail's capacity needs through 2021. However, Otter Tail's system by itself is unable to produce enough energy to meet its energy needs at a reasonable price without access to the wholesale market, and the Department's decision to restrict Otter Tail's access to the wholesale market beginning in 2019 therefore results in the addition of a 200 MW gas CT in 2019, rather than 2021 (when there is a capacity need).

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[13] As described above, these prices represent the 2014 fixed price for a 20-year PPA, which is escalated at 3 percent per year thereafter.

[14] The Department notes that in order for Strategist to find a solution in this contingency, the Department had to alter its wind availability and allow Strategist to select up to 300 MW of wind in 2015.

The Department notes that this expansion plan is relatively stable across all 37 contingencies. In the two contingencies with high ($34/ton) carbon costs, and the five contingencies with higher gas prices, Strategist replaced the 200 MW CT in 2019 with three smaller, more efficient CT's totaling 250 MW added from 2019 to 2021 (50 and 100 MW CT's in 2019, followed by a 100 MW CT in 2021). In these seven contingencies, the expansion plan from the base contingency (which includes the 200 MW CT in 2019) was ranked as one of the eight least expensive expansion plans, and the total cost differences between this plan and the least cost plan were small (0.54 percent or less).

In the contingencies with wind priced at $65/MWh or higher, the model selected one or two fewer wind units relative to the base contingency, and pulled the 50 MW CT in 2024 forward in time to 2021 or 2022.

b. Scenarios 2 and 3

Attachment 4 summarizes the least cost expansion plans produced by each of the 37 contingencies run by the Department on Scenario 2, which used the coincident peak reliability method. The expansion plan selected in the base contingency is identical to the expansion plan from the Scenario 1 base contingency, except that the first 50 MW CT is delayed from 2017 to 2021 (that is, 100 MW wind units in 2017, 2019, and 2021; 200 MW CT in 2021; and 50 MW CTs in 2021 and 2024).

Attachment 5 contains the least cost expansion plan produced by each of the 37 contingencies run on Scenario 3, which used the 50DF reliability method. The Department notes that for most contingencies, the expansion plans produced by Scenarios 2 and 3 are identical.

When comparing the expansion plans produced by the base contingency from Scenarios 1, 2, and 3, the Department notes that by 2021 the systems created in each scenario are identical. The only difference between the expansion plans is that a 50 MW CT selected in 2017 in Scenario 1 is delayed until 2021 in Scenarios 2 and 3. Additionally, the Department notes that the difference in costs between the different expansion plans is small, as Scenario 2 is 0.46 percent less costly than Scenario 1, and Scenario 3 is 0.44% less costly,[15] as shown in Attachment 2.

The Department further notes that the addition of 300 MW of wind is a robust result in Scenarios 1, 2, and 3 up to a base price of $60/MWh to $65MWh.

[15] The Department notes that the expansion plan produced by the base contingency for Scenario 3 requires small amounts of deferral capacity in 2017 and 2018 (7 MW and 8 MW, respectively).

c. Scenario 4

As noted above, the Department's Scenario 4 is identical to Scenario 1 (NCP reliability method; market off in 2019; mid-carbon costs; high externalities), except that in Scenario 4, additional wind and solar resources are not made available as energy resources. Attachment 6 contains the least cost expansion plan for each contingency run for Scenario 4. The base contingency expansion plan includes a 200 MW CT in 2017, 100 MW wind units in 2019 and 2021, and 50 MW CT units in 2021 and 2022. Similar to Scenarios 1, 2, and 3, the expansion plans produced by the contingencies with higher gas costs eliminate the 200 MW CT in 2017 and replace it with a combination of smaller, more efficient (in terms of heat rate) CTs. Additionally, the Department notes that the expansion plan produced by the base contingency is a top-five expansion plan in each of the high gas cost contingencies, and the cost differences between the base contingency expansion plan and the least-cost expansion plan in these high gas contingencies are small.

The Department notes the Scenario 4 expansion plans generally contain one fewer wind unit than the expansion plans for Scenarios 1, 2, and 3, and are 1-3 percent more expensive for every contingency.

d. Scenario 5

The Department considered a scenario, Scenario 5, in which Otter Tail's oil-fired peaking units (Jamestown Units 1 and 2, and Lake Preston) are retired at the end of 2022, which is consistent with the Company's most recent depreciation study.[16] Otter Tail's Strategist modeling assumes that these three peaking units are available throughout the entire study period. This scenario is otherwise identical to Scenario 1 (non-coincident peak, market off in 2019, mid-carbon cost, and high externalities). Attachment 7 summarizes the top expansion plans produced by each contingency for Scenario 6.

With exception of a few of the high-priced wind contingencies, the expansion plans produced by Scenario 6 are nearly identical to those produced by Scenario 1, with the only difference being that in Scenario 6, approximately 12 MW of deferral capacity is needed in 2023, to make up for the retired capacity, until a 50 MW CT is added in 2024.

The reason that the expansion plans are nearly identical, despite the fact that nearly 50 MW of capacity is being retired in Scenario 6, is that in Scenario 1, new resources are not added to meet the required capacity reserve margin, but rather to supply necessary energy. While Otter Tail's oil peaking units are available and capable of producing energy, Otter Tail modeled the units in Strategist as being on permanent outage over the entire study period. In its response to Department Information Request No. 17, Otter Tail stated that it "views the diesel units as

[16] See Docket No. E017/D-13-795.

capacity-only resources and not as energy resources (due to high fuel costs)." Because new units are being added to supply energy, not capacity, the capacity provided by Otter Tail's diesel peaking plants is not needed.

Attachment 2 shows that in all contingencies modeled by the Department, retiring these peakers is slightly more cost effective than not. Additionally, the Department notes that Otter Tail included a $2 million investment in each of these units ($6 million total) in 2019 as a representative amount needed to extend their lives beyond 2020. The Department did not remove these investments in its analysis; thus, if all or part of these investments can be avoided by retiring these units in 2022, the Department's analysis may understate the cost savings.

e. Scenario 6

The Department's last scenario, Scenario 6, used the NCP reliability method, but allowed Otter Tail full access to the wholesale energy market during the study period. Attachment 8 summarizes the expansion plans produced for Scenario 6. The Department notes that, relative to Scenario 1, Scenario 6 adds an extra wind unit in 2023. Scenario 6 also adds 50 MW CTs in 2017 and 2021 (versus 2017 and 2024 in Scenario 1) and adds a 100 MW CT in 2021 (rather than a 200 MW CT in 2019).

As shown in Attachment 2, Scenario 6 is less costly than Scenario 1 in all scenarios analyzed. The Department notes that the cost premium associated with Scenario 1 can be thought of as the price of insurance against risks associated with Otter Tail's exposure to its estimates of future prices in the wholesale market because Scenario 1 assumes that Otter Tail owns the means of energy production rather than relying so heavily on the market.

The Department notes that, while not shown in Attachment 8, Scenario 6 tends to rely more small amounts of deferral capacity in the later years of the planning period than Scenario 1.

f. Solar Energy Standard

The Solar Energy Standard requires utilities to generate at least 1.5 percent of the energy sold to its retail customers in Minnesota by 2020. As discussed above, the Department ran contingencies on each scenario to estimate the cost of meeting this requirement. The Solar Energy Standard, however, also sets a goal for the State that 10 percent of retail electric sales in Minnesota be generated by solar energy. In order to generate 10 percent of its energy from solar resources, the Department estimates that Otter Tail would have to install 135 MW of solar units by nameplate capacity. The Department ran three additional contingencies on Scenario 1, in which it forced Strategist to select 135 MW of solar resources towards the end of the planning period, in 2028, at Otter Tail's assumed base, high, and low prices. Table 8 summarizes the results.

Table 8
Cost of Achieving 10% of
Energy from Solar by 2028

	PVSC ($000s)	% Increase from Dept. Base
Department Base	3,971,851	
Solar Base $133/MWh	4,109,110	3.46%
Solar High $150/MWh	4,115,764	3.62%
Solar Low $75/MWh	4,008,558	0.92%

As shown, the cost of achieving 10 percent of energy generated by solar resources ranges from slightly less than one percent to approximately 3.6 percent, depending on the assumed price per MWh. Table 8 shows that, for the SES to be cost effective, the cost of solar energy would have to be less than $75/MWh.

g. Greenhouse Gas Emissions Goal

As noted above, the Department ran a contingency on each scenario which restricted Otter Tail's annual carbon dioxide emissions over the period 2015-2024 to 85 percent of the Company's 2005 CO_2 emissions and restricted annual CO_2 emission from 2025 on to 70 percent of the Company's 2005 emissions. Attachment 2 shows that at the Department's assumed base wind prices, achieving this goal is cost-effective. The Department notes, however, that to do so would require Otter Tail to install 300 MW of wind in 2015, as shown in the expansion plans included in Attachments 3 through 8.

Additionally, the Department notes that this result is also very sensitive to the assumed price of wind. As shown in Table 9 below, meeting the CO_2 reduction goal becomes cost neutral at a wind price of approximately $50/MWh, and while the Department assumed a fixed cost of $45/MWh, this assumed price reflects the "all-in" cost of wind, including any necessary transmission upgrades. Thus, despite some of the low levelized wind costs seen last year, with the expiration of the production tax credit, the price Otter Tail would have to pay for wind could exceed $50/MWh.

Table 9
Cost of Complying with
Greenhouse Gas Emissions Goal

	PVSC ($000s)	% Increase from Dept. Base
Dept Base.	3,971,851	0.0%
Cost of Meeting CO_2 Goal		
Wind $35/MWh	3,667,616	-7.7%
Wind $40/MWh	3,765,583	-5.2%
Wind $45/MWh	3,863,550	-2.7%
Wind $50/MWh	3,958,033	-0.3%
Wind $55/MWh	4,037,657	1.7%
Wind $60/MWh	4,117,283	3.7%
Wind $65/MWh	4,188,890	5.5%
Wind $70/MWh	4,251,910	7.1%
Wind $75/MWh	4,312,226	8.6%
Wind $80/MWh	4,372,541	10.1%

h. Cost-Effectiveness of Wind with No Externalities

One common result across all of the Department's Strategist runs is the selection of large amounts of wind, often 200 to 400 MW. In response to these results, the Department completed additional analysis on the effects emissions costs have on the selection of wind. The Department began with the assumptions used in Scenario 1, and removed all emissions costs (including both externality values and the internal cost of carbon regulation). The Department then ran contingencies with the price of wind increasing from $30/MWh to $80/MWh in five-dollar increments.

For each contingency, the Department reviewed the top ten expansion plans, ranked by PVSC, and noted the number of 100 MW wind units selected in each expansion plan, and the years in which the wind units were selected. The results are summarized in Table 10 below.

Table 10: Wind Units Selected When Externalities Not Considered

	# of Top Ten Expansion Plans with at least:			# of Top Ten Expansion Plans with:		
2014 Price of Wind	Three 100 MW Wind Units	Two 100 MW Wind Units	One 100 MW Wind Unit	Wind Added in 2017	Wind Added in 2019	Wind Added in 2021
$30/MWh	10	10	10	10	10	10
$35/MWh	10	10	10	10	10	10
$40/MWh	10	10	10	10	10	10
$45/MWh	1	9	10	6	7	7
$50/MWh	0	4	10	4	5	5
$55/MWh	0	0	10	2	4	4
$60/MWh	0	0	8	1	3	4
$65/MWh	0	0	5	0	2	3
$70/MWh	0	0	2	0	0	2
$75/MWh	0	0	0	0	0	0
$80/MWh	0	0	0	0	0	0

As shown, in Table 10 above, at up to a 2014 price of $40/MWh, the addition of three 100 MW units is cost-effective even when the costs of emissions are not considered.[17] At a 2014 wind price of $45/MWh, two wind units are consistently selected (in 9 of the top 10 plans); in only 4 of the top 10 plans, no wind is added in 2017; in 3 of the top 10 plans no wind is added in 2019; and in the remaining three plans, no wind is added in 2021. Thus, in the $45/MWh contingency, the timing of the additions of wind is only slightly variable in that a similar number of the top 10 plans add a wind unit in 2017 (6 plans), 2019 (7 plans), and 2021 (also 7 plans).

At prices above $50/MWh, however, early wind is not cost-effective if externalities are not considered, as evidenced by the steep drop-off in the amount of wind selected in the higher-price contingencies. Also, Table 10 above shows that only 2 of the top 10 plans add wind in 2017 when a price of $55/MWh is assumed.

The Department completed one additional Strategist run with wind priced at $50/MWh, which included a wind unit forced into the expansion plan in 2017. In addition to the wind in 2017, Strategist selected 50 MW CT's in 2017 and 2021, and a 200 MW CT in 2019; an expansion plan very similar to the plan produced by the base contingency in Scenario 1. The Department notes that in this run, Otter Tail's baseload units (Big Stone and Coyote) are run at or near

[17] As discussed above, the price of wind referenced is the price in 2014, which escalates at a rate of three percent per year. Thus, in the "$45/MWh" contingency, wind added in 2017 would be assumed to have a fixed price of $49.19/MWh (which reflects three years of inflation).

maximum capacity, with capacity factors of 80 to 90 percent, and Strategist relies heavily on the new CT's to produce energy, with capacity factors ranging from 20 to 60 percent in the years after Hoot Lake is retired. These capacity factors are much higher than would typically be expected for CTs and are indicative of Otter Tail's need for reasonably priced energy. The Department notes that if this expansion plan were to be implemented, it would be reasonable to expect Otter Tail to substitute economical market purchases for energy from the new CTs, which would result in lower capacity factors. However, without the new CTs, Otter Tail would have no choice but to rely on the market at times of peak demand, exposing Otter Tail's ratepayers to the risks of the market.

i. Recommended/Preferred Plan

Considering the results as a whole, the Department recommends as its preferred plan the expansion plan produced by the Scenario 1 (NCP reliability method, market off in 2019, mid-CO_2 costs and high externalities) base contingency, summarized in Table 11 below.

Table 11: Proposed Action Plan

2014	Pursue 1.7% DSM
2015	
2016	
2017	Add 100 MW Wind and 50 MW CT
2018	
2019	Add 100 MW Wind, 200 MW CT and 21 MW Solar
2020	Retire Hoot Lake Plant, Units 2 and 3 at End of Year
2021	Add 100 MW Wind
2022	
2023	
2024	Add 50 MW CT
2025	
2026	
2027	
2028	

As discussed above, the 50 MW CT selected in 2017 is delayed until 2021 when the CP and 50DF reliability methods are used. Thus, the timing difference can be thought of as insurance against the uncertainty associated with Otter Tail's forecast of coincident peak. While this plan, generated with the NCP reliability method, is marginally more expensive than the least cost expansion plans created using the CP and 50DF reliability methods, the uncertainty associated with MISO's new construct, along with OTP's reliance on the wholesale market and forecasts of low wholesale market prices warrants the small cost premium as a reasonable trade-off for the increased reliability that the NCP method offers. Specifically, the wind unit in 2017 can be thought of as insurance against the uncertainty associated with Otter Tail's exposure to the wholesale market.[18] At least 100 MW of wind in 2017 is cost effective, even without externalities, at wind prices of $50/MWh. Therefore, the Department recommends that the Commission order the Company to issue a wind RFP to obtain actual market prices and file the results of the request for proposals (RFP) as either a signed power purchase agreement, a self-build project, or an explanation regarding why no wind was chosen.

The Department notes that its recommended expansion plan results in reserve margins well above the required reserve margin, particularly during the period after market access is restricted (beginning of 2019), but before Hoot Lake is retired (end of 2020). The Department notes that this result is partially caused by Otter Tail having roughly 100 MW of capacity-only resources during that time period; a 50 MW capacity contract and the Company's three oil-fired peaking units, which have a combined capacity of 48.4 MW. Because Otter Tail's system can draw no energy from those resources, in order to meet the system's energy needs, Strategist is forced to add more resources than are necessary to meet the system's capacity needs.[19]

Figure 8 below illustrates Otter Tail's energy production by fuel type over the planning period (2014-2028) under the Department's preferred plan. As shown, the Department's preferred plan introduces some diversity into Otter Tail's fleet of resources with the addition of three gas CT's totaling 300 MW, as well as 300 MW of new wind, which largely replace Otter Tail's market energy purchases as the market access is restricted in 2019.

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[18] At prices of $50/MWh, wind in 2017 would provide no-cost insurance.

[19] As discussed above, Company stated intention is to treat its oil-fired peakers as capacity-only resources, and modeled those units as being on permanent outage during the planning period.

**Figure 5: Otter Tail's Fuel Mix Under
The Department's Proposed Plan**

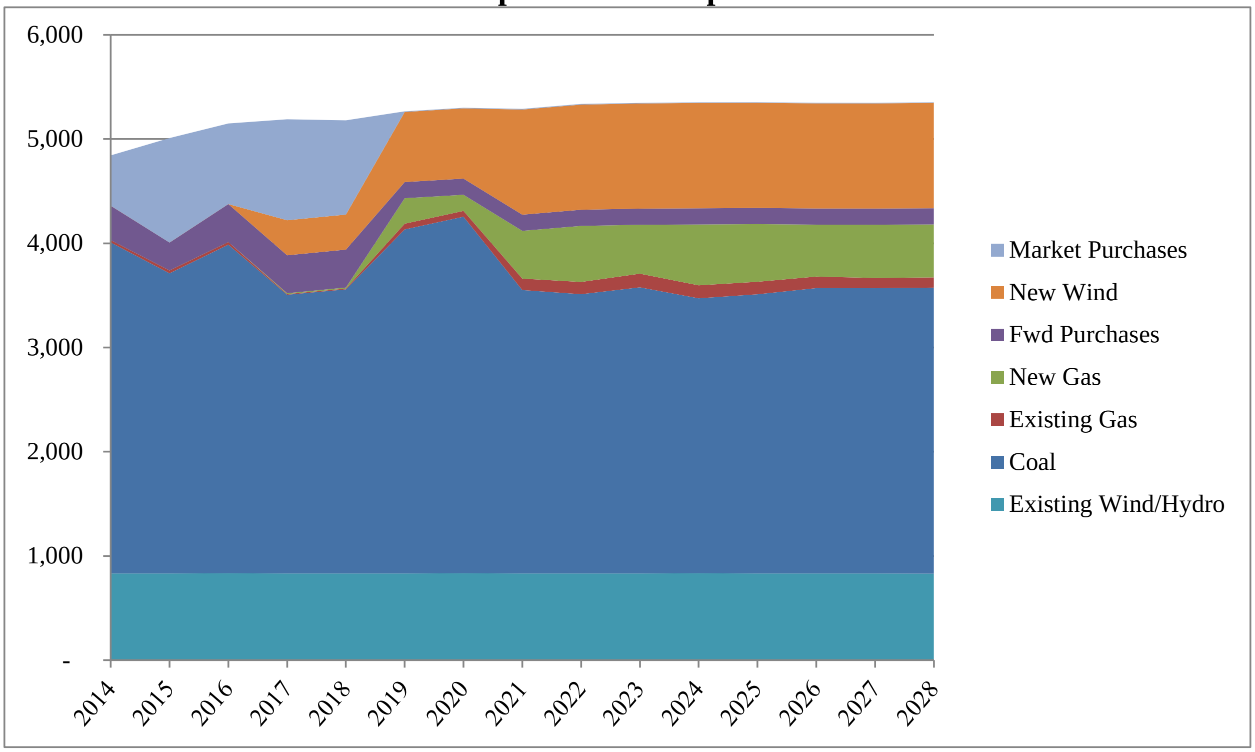

Figure 8 shows that about 80 percent of Otter Tail's energy needs are addressed by the Company's existing coal and renewable resources. The main issue in this plan is how to fill approximately 1,000 GWh of energy needs, 20 percent of Otter Tail's system energy requirement. The Department's proposed plan addresses the energy deficit through short term purchases in the near future and additions of wind and gas units starting in 2017 and gradually increasing until a stable resource mix is reached in 2021.

Additionally, as discussed above, under the Department's preferred plan, the capacity provided by Otter Tail's three diesel units is not necessary for Otter Tail to satisfy its reserve obligations. Because that capacity is not needed, and the Company's intention for those units is to treat them as capacity-only resources and generate no electricity with them, the need to keep those units operational is questionable. While the retirement of Otter Tail's diesel peaking units is not part of the Department's preferred plan, the Department's analysis indicates that retirement would likely be a cost-effective decision. Therefore, the Department recommends that Otter Tail include in its next resource plan an analysis of possible retirement scenarios for its Jamestown and Lake Preston units.

3. Summary of Modeling Review

The Department's modeling results are generally consistent across all of the Strategist runs completed, regardless of reliability method chosen. Most of the least cost expansion plans include 300 MW of new wind to be installed by 2021, as long as wind is priced at $60/MWh or less. Most expansion plans also include 300 MW of peaking capacity to be installed over the period 2017-2024, although the specific timing varies in different scenarios and contingencies.

The Department's Strategist results indicate a need for energy (as evidenced by the selection of 300 MW of new wind) on Otter Tail's system. The Department also notes that in addition to the 50, 100, and 200 MW gas CT's (i.e. peaking plants) Otter Tail included in its Strategist analysis only one combined cycle (CC) alternative, a 300 MW natural gas CC. CC's run at higher capacity factors than CT's and thus provide more energy throughout the year than CTs. A 300 MW CC is a large plant relative to Otter Tail's size, and it would be difficult for a 300 MW CC to be selected as a cost-effective resource. However, a smaller CC (say, 200-250 MW) may be a reasonable alternative. The Department requests that Otter Tail address this issue in reply comments.

The Department recommends that the Commission require Otter Tail to:

a. use Strategist in the Company's next IRP;
b. include, in all future IRPs, a forecast of the market cost of SO_2 allowances, as well as any other emissions allowances granted to the Company;
c. include an analysis of the effects of retiring its Jamestown and Lake Preston peaking units in its next IRP;
d. modify Otter Tail's plan to include 1.7 percent DSM; 100 MW of wind and a 50 MW gas CT in 2017; and 100 MW of wind, a 200 MW CT, and 21 MW of solar in 2019; and
e. issue a wind RFP to obtain actual market prices and file the results of the RFP as either a signed power purchase agreement, a self-build project, or an explanation regarding why no wind was chosen.

The Department recommends that Otter Tail provide a discussion in reply comments of whether a CC alternative sized between 200 and 250 MW is a reasonable resource alternative to consider.

F. COMPLIANCE WITH THE RENEWABLE ENERGY OBJECTIVE

1. Background

Prior to the 2007 Legislative Session, Minn. Stat. §216B.1691 required utilities to make a good faith effort to obtain 10 percent of their Minnesota retail sales from eligible energy technologies by 2015, and to obtain 0.5 percent renewable energy from biomass technologies. The 2007 Minnesota Legislature amended Minn. Stat. §216B.1691 to include a Renewable Energy

Standard (RES) beginning in 2010. As amended, Minn. Stat. §216B.1691, Subd. 2 sets forth the Renewable Energy Objective in place through 2010 and requires that:

> Each electric utility shall make a good faith effort to generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers or the retail customers of a distribution utility to which the electric utility provides wholesale electric service so that commencing in 2005, at least one percent of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies, and seven percent of the electric utility's total retail electric sales to retail customers in Minnesota by 2010 is generated by eligible energy technologies.

Minn. Stat. §216B.1691, Subd 2a establishes the RES that utilities must meet through 2025 and specifically requires that:

> …each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies by the end of the year indicated:
>
> | | |
> |---|---|
> | 2012 | 12 percent |
> | 2016 | 17 percent |
> | 2020 | 20 percent |
> | 2025 | 25 percent |

The statute no longer requires that a portion of the renewable energy generation come from biomass technologies. An eligible energy technology is defined by Minn. Stat. §216B.1691, Subd. 1 as an energy technology that:

> Generates electricity from the following energy sources: (1) solar; (2) wind; (3) hydroelectric with a capacity of less than 100 megawatts; (4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this clause; or (5) biomass, which includes without limitation, landfill gas, an anaerobic

> digester system, and an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

Minn. Stat. §216B.1691, subd. 2(d) directs the Commission to "issue necessary orders detailing the criteria and standards by which it will measure an electric utility's efforts to meet the renewable energy objectives of subdivision 2 to determine whether the utility is making the required good faith effort."

The Commission set forth the criteria for determining compliance with the RES Statute after taking comments from effected parties in a number of Orders.[20] Among the resources the Commission has determined ineligible for meeting the RES are resources used for green pricing, resources that do not meet the statutory definition of eligibility, and generation assigned to compliance for other regulatory purposes such as another state's Renewable Portfolio Standard Requirements (RPS).

The 2007 amendment to Minn. Stat. §216B.1691, Subd. 4 required the Commission to establish a program for tradable Renewable Energy Credits (RECs) by January 2008, and to require all electric utilities to participate in a Commission-approved REC tracking system once such a system was in operation.

The Commission subsequently adopted the use of the Midwest Renewable Energy Tracking System (M-RETS), a multi-state REC tracking system, as the REC tracking system under Minn. Stat. §216B.1691, Subd. 4(d), and required Minnesota utilities to participate.[21] Specifically, the Commission required utilities to complete the online registration process and sign the Terms of Use agreement with the M-RETS system administrator APX, Inc., and receive account approval

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[20] *In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691*, Docket No. E999/CI-03-869, Initial Order Detailing Criteria and Standards for Determining Compliance with Minn. Stat. §216B.1691 and Requiring Customer Notification by Certain Cooperative, Municipal, and Investor-Owned Distribution Utilities. (June 1, 2004)
In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691, Docket No. E999/CI-03-869; *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits*, Docket No. E999/CI-04-1616, Second Order Implementing Minn. Stat. §216B.1691, Opening Docket to Investigate Multi-State Program for Tracking and Trading Renewable Credits and Requesting Periodic Updates from Stakeholder Group; (October 19, 2004)
In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691, Docket No. E999/CI-03-869, Order After Reconsideration (August 13, 2004)

[21] *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits*, Docket No. E999/CI-04-1616, Order Approving Midwest Renewable Energy Tracking System (M-RETS) Under Minn. Stat. §216B.1691, Subd. 4(d), and Requiring Utilities to Participate in M-RETS (October 9, 2007)

from APX by January 1, 2008. In addition, the Commission directed utilities to make a substantial and good faith effort to create a system account and sub-accounts for its organization, and to register its generation units/facilities in the M-RETS system by March 1, 2008.

In its December 18, 2007 *Order Establishing Initial Protocols for Trading Renewable Energy Credits,* the Commission adopted a four-year shelf life for all renewable energy credits to be used for compliance with the Minnesota RES. A four-year shelf life allows a REC to be retired towards MN RES compliance in the year of generation and during the four years following the year of generation.

Finally, in its December 3, 2008 *Third Order Detailing Criteria and Standards for Determining Compliance under Minn. Stat. §216B.1691 and Setting Procedures for Retiring Renewable Energy Credits,* the Commission directed utilities to begin retiring RECs equivalent to one percent of their Minnesota annual retail sales for the 2008 and 2009 compliance year by May 1st of the following year. Upon retirement, RECs are transferred into a specific Minnesota RES retirement account and, once retired, are not available to meet other state or program requirements, thus addressing the statutory prohibition against double counting the RECs and promoting the environmental benefits of renewable energy. The Commission further directed the utilities to submit a compliance filing demonstrating their compliance with the RES by June 1.

In addition to amending the RES Statute, Minn. Stat. §216B.241, Subd. 1c(b) was added to establish an energy-savings goal as part of a utility's conservation improvement plan, and states:

> Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d). The savings goals must be calculated based on the most recent three-year weather normalized average.

The attainment of the 1.5 percent energy savings goal will reduce a utility's forecasted retail sales, and consequently lower the amount of renewable generation required to meet RES obligations.

In 2013 a Solar Energy Standard (SES) was passed by state legislature. Minn. Stat. 216B.1691 Subd. 2f requires that in addition to the RES obligation a publicly owned utility obtain at least 1.5 percent of its Minnesota retail sales from solar energy by the end of 2020. Of that 1.5 percent, at least ten percent must be from solar facilities of 20 kW or less. The statute excludes certain retail sales to iron mining, paper and wood products manufacturers from the calculation of the SES requirement.

2. *OTP's Renewable Standard*

Table 12, below, summarizes OTP's RES requirement in MWhs over the forecast period. OTP's forecasted retail sales are adjusted to reflect energy savings from CIP and DSM.

Table 12: OTP's Renewable Energy Standard

Year	MN Retail Sales	RES Percentage	RES Requirement (MWhs)
2013	2,164,446	12%	259,734
2014	2,210,000	12%	265,200
2015	2,353,000	12%	282,360
2016	2,493,000	17%	423,810
2017	2,439,000	17%	414,630
2018	2,420,000	17%	411,400
2019	2,525,000	17%	429,250
2020	2,522,000	20%	504,400
2021	2,546,000	20%	509,200
2022	2,590,000	20%	518,000
2023	2,578,000	20%	515,600
2024	2,566,000	20%	513,200
2025	2,555,000	25%	638,750
2026	2,544,000	20%	636,000
2027	2,535,000	20%	633,750
2028	2,526,000	20%	631,500

Over the forecast period, OTP's RES requirement increases from 265,200 RECs in 2014 to 631,500 IN 2028.

3. *Existing Generation Resources*

In 2013, OTP had system-wide renewable generation of 416,355 MWhs. Using Minnesota's percentage of system sales of 49.5 percent, 206,079 MWhs would be available for Minnesota RES compliance as shown in Table 13 below.

Table 13: Minnesota RES Compliance with Existing Resources

Year	MN REO/RES Requirement MWh	2013 Renew. Generation (MWh)	Existing Generation less RES Surplus/ (Deficit) MWh	Cumulative
				Beg. Balance (incl. 2013 gen.) 608,207
2013	259,734	206,079	(53,655)	348,473
2014	265,200	206,079	(59,121)	289,352
2015	282,360	206,079	(76,281)	213,071
2016	423,810	206,079	(217,731)	(4,660)
2017	414,630	206,079	(208,551)	(213,211)
2018	411,400	206,079	(205,321)	(418,532)
2019	429,250	206,079	(223,171)	(641,703)
2020	504,400	206,079	(298,321)	(940,024)
2021	509,200	206,079	(303,121)	(1,243,145)
2022	518,000	206,079	(311,921)	(1,555,066)
2023	515,600	206,079	(309,521)	(1,864,587)
2024	513,200	206,079	(307,121)	(2,171,708)
2025	638,750	206,079	(432,671)	(2,604,379)
2026	636,000	206,079	(429,921)	(3,034,300)
2027	633,750	206,079	(427,671)	(3,461,971)
2028	631,500	206,079	(425,421)	(3,887,392)

Assuming only Minnesota's percentage of system sales is available for Minnesota RES compliance, OTP's annual existing renewable generation is insufficient to meet its RES requirement. The Commission adopted a four-year shelf life for RECs, thus allowing a utility to retire a REC for compliance with RES up to four years after the year of generation. OTP has a total balance of 1,228,802 in unretired RECs that can be carried forward for future years RES compliance. Assuming only 49.5 percent or 608,207 (Minnesota's percentage of system sales) is available for Minnesota RES compliance, the combination of existing annual renewable generation plus unretired REC balances gives OTP sufficient renewable generation to meet its Minnesota RES requirement through 2016.

In addition to Minnesota, OTP has customers in North and South Dakota. North and South Dakota both have a voluntary Renewable Energy Obligation of 10 percent beginning in 2015. According to OTP's IRP, neither North Dakota nor South Dakota have established a shelf life for RECs or taken any position on whether generation used to meet green pricing obligations can also count towards the Company's REO in each state. Table 14 below estimates OTP's ability to meet its renewable obligations in all three states on an annual basis, as well as given its current level of renewable generation, accumulated RECs, and assuming a four-year shelf life and no green pricing counts towards REO/RES compliance.

Table 14: RES/REO Compliance with Existing Resources
Minnesota, North Dakota & South Dakota

Year	Total REO/RES Requirement MWh	2013 Renew. Generation (MWh)	Existing Generation less RES Surplus/ (Deficit) MWh	Cumulative
				Beg. Balance:
2013	259,734	416,335	156,601	969,068
2014	265,200	416,335	151,135	1,120,203
2015	509,460	416,335	(93,125)	1,027,078
2016	650,810	416,335	(234,475)	792,603
2017	642,730	416,335	(226,395)	566,208
2018	640,900	416,335	(224,565)	341,643
2019	660,250	416,335	(243,915)	97,728
2020	736,800	416,335	(320,465)	(222,737)
2021	743,000	416,335	(326,665)	(549,402)
2022	753,100	416,335	(336,765)	(886,167)
2023	752,000	416,335	(335,665)	(1,221,832)
2024	750,900	416,335	(334,565)	(1,556,397)
2025	877,550	416,335	(461,215)	(2,017,612)
2026	874,500	416,335	(458,165)	(2,475,777)
2027	873,150	416,335	(456,815)	(2,932,592)
2028	872,200	416,335	(455,865)	(3,388,457)

When North and South Dakota's REO obligations are added into the total renewable generation requirement, OTP appears able to meet its obligations with current generation and its unretired REC balances through 2019.

4. Compliance with RES

In its May 28, 2013 compliance filing in Docket No. E999/PR-13-186, OTP reported 2012 Minnesota retail sales of 2,076,032 MWh, and retired 249,124 RECs or 12 percent of its Minnesota retail sales to comply with Minn. Stat. §216B.1691, Subd. 2(a).

OTP has not proposed the addition of any renewable generation in its current resource plan. The Department's proposed plan includes the addition of 100 MW in 2017, 2019 and 2021. Table 15 estimates OTP's ability to meet its Minnesota RES requirements with the addition of 300 MW of wind over its planning period, and assuming that 49.5 percent of the RECs generated are available to meet Minnesota's RES. Wind additions were assumed to have a 35 percent capacity factor.

Table 15: OTP Estimated RES Compliance
Wind at 35% Capacity Factor

Year	MN RES Requirement MWh	Total Existing + DOC Recommended Additions	Cumulative MN RES Surplus/ (Need) (Prev Yr Bal. + Col B. –Col. A)	Cumulative System RES Surplus/(Need)
2013	259,734	206,079	348,473	969,068
2014	265,200	206,079	289,352	1,120,203
2015	282,360	206,079	213,071	1,027,078
2016	423,810	206,079	(4,660)	792,603
2017	414,630	357,846	(61,444)	872,808
2018	411,400	357,846	(114,998)	954,843
2019	429,250	509,613	(34,635)	1,324,128
2020	504,400	509,613	(29,422)	1,616,863
2021	509,200	661,380	122,758	2,209,998
2022	518,000	661,380	266,138	2,793,033
2023	515,600	661,380	411,918	3,377,168
2024	513,200	661,380	560,098	3,962,403
2025	638,750	661,380	582,728	4,420,988
2026	636,000	661,380	608,108	4,882,623
2027	633,750	661,380	635,738	5,345,608
2028	631,500	661,380	665,618	5,809,543

Assuming only a portion of the RECs generated by the wind additions are available to meet Minnesota RES, OTP would have insufficient renewables to meet its RES requirement for several years in the middle of the planning period. However, such deficits would be short-lived.

In Appendix G to its resource plan, OTP details its REO/RES compliance strategy. The Company specifically indicates that it expects to transfer RECs from North and South Dakota, as necessary, to maintain its Minnesota compliance. The Department estimates that OTP has sufficient existing renewables to meet its system-wide renewable obligations through 2019. As reflected in the Cumulative System column to Table 15, the Department expects OTP to have sufficient RECs with the recommended wind additions to meet its system RES obligations.

5. SES Requirements

The Commission is in the process of establishing annual reporting requirements for utilities subject to the SES. The first report will be due on June 1, 2014. In July 2013, the Commission issued a notice requesting comment on the customers excluded from the SES under Minn. Stat. § 216B.1691, subd. 2f. Based on 2012 sales, OTP reported 69,182 MWhs of sales to excluded customer groups or 3.3 percent of its 2012 Minnesota retail sales.

Using OTP's 2020 Minnesota retail sales forecast and a 3.3 percent exclusion, the Company would be required to obtain solar energy of 1.5 percent of 2,441,432 MWhs or approximately 36,621 S-RECs. As noted in the comments above, the Department's recommended plan includes the addition of 21 MW of solar by 2019 to meet OTP's SES requirement. In addition, the Department evaluated the cost of obtaining 10 percent of the Company's Minnesota retail sales by 2028, and estimates the cost premium to be between 1.0 and 3.6 percent.

H. ENVIRONMENTAL ISSUES

The Department generally reviews utility resource plans for compliance with pending state and national environmental legislation that impacts the electric utility's operations. OTP discussed environmental regulations impacting its electric utility operations in Appendix E of its resource plan. The Company addressed environmental regulations for sulfur dioxide (SO_2), nitrous oxide (NO_x), particulate matter (PM) and mercury (Hg).

1. Sulfur Dioxide and Nitrous Oxide

The Acid Rain Program aims to reduce emissions of SO_2 and NO_x. A national cap and trade program for SO_2 allowances is in place. OTP is able to meet SO_2 requirements at its Big Stone and Hoot Lake plants by using low sulfur subbituminous coal, while emissions control equipment is in place at its Coyote Station facility. OTP does not anticipate a need to purchase allowances to meet SO_2 requirements. The Company installed low NO_x burners at its Hoot Lake Plant Units 2 and 3, and over-fired air equipment at its Big Stone Plant to meet emission reduction requirements for NO_x.

2. Particulate Matter

The Clean Air Interstate Rule (CAIR) was intended to reduce the transport of various emissions, including SO_2, NO_x and particulate matter, to downwind states. The Cross-State Air Pollution Rule (CSAPR) was issued by the EPA to address court concerns with CAIR; however it has also been challenged in the courts. Given the uncertainty with these two rulemakings at the time Otter Tail filed its resource plan, OTP indicated that it is uncertain, what actions of any will be required to comply.

Recently, the Supreme Court ruled in favor of CSAPR. Thus, the Department recommends that Otter Tail report in its reply comments as to how this information may affect their resource plan.

3. Mercury

Under the EPA's MATS rule, OTP is required to reduce its mercury emissions by April 2015, or if granted a one-year extension, by 2016. OTP states it is upgrading electrostatic precipitators at its Hoot Lake Units 2 and 3, and installing activated carbon injection systems at its Hoot Lake, Coyote and Big Stone generation facilities. In addition, the Minnesota Pollution Control Agency

(MPCA) has a process underway as part of the Clean Water Act to reduce mercury emissions by targeted amounts. OTP states it expects Hoot Lake Plants Units 2 and 3 will be required to file a mercury emissions reduction plan by 2015 with the MPCA to remove 70 percent of the mercury emitted by each unit by 2025. The Company indicates that controls put in place to meet MATS requirements should also result in compliance with water quality rules.

4. Regional Haze Program

The Regional Haze Program is intended to address visibility impairment in Class I wilderness areas, including the Boundary Waters Canoe Area (BWCA), and North Dakota's Theodore Roosevelt National Park. If a unit is determined to contribute to visibility impairment, the Company is required to install best available retrofit technology (BART) to reduce impairment. OTP indicates that dispersion modeling done by the MPCA determined that Hoot Lake Unit 3 did not significantly contribute to visibility impairment, and consequently did not require additional controls. OTP obtained approval to install emissions control equipment including a scrubber, baghouse, and over-fired air equipment at its Big Stone Plant in Docket No. E017/M-10-1082.

5. Greenhouse Gases

In 2013, the EPA proposed New Source Performance Standards that would regulate greenhouse gases (GHG) from new generating units, and is expected to issue rules governing existing plants in June of 2014. OTP expects EPA's rules for new generation plants to be finalized in advance of any new generation facilities it may build.

6. Coal Combustion Residuals

The EPA has issued a proposed rule for regulating the disposal of coal ash generated by coal combustion generation facilities. The proposed rule contemplates two possible regulatory options. The first option would create a special classification for coal ash that would subject ash disposal to many of the regulatory requirements applicable to hazardous waste, but would not categorize it as hazardous waste. The second option would regulate coal ash disposal as a non-hazardous solid waste, and establish national minimum standards for its safe disposal. OTP states that Hoot Lake has a dry ash disposal site regulated by the MPCA that includes a groundwater monitoring system. Big Stone's dry disposal site is regulated by the State of South Dakota, while Coyote's two dry ash disposal sites are regulated by North Dakota. OTP indicates that it continues to monitor development of EPA's rules governing coal ash disposal to determine if any additional requirements will be needed at any of its disposal sites.

7. Recommendation

The DOC concludes that OTP is adequately tracking environmental regulations that might impact its operations. The Department requests that OTP report in its Reply Comments on how the Supreme Court's ruling on EPA's CSAPR may affect OTP's resource plan.

G. MINNESOTA GREENHOUSE GAS EMISSIONS REDUCTION GOAL

In 2013, the Minnesota Legislature passed amendments to Minnesota Statutes §216B.2422, subd. 4. The newly amended legislation now states (new language underlined):

> The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. <u>The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f</u>.

On August 5, 2013, the Minnesota Public Utilities Commission issued a Notice of Information in Future Resource Plan Filings (Commission's Letter). The Commission Letter states, in part:

> **PLEASE TAKE NOTICE** that the Commission expects utilities to include in their resource plans filed after August 1, 2013 an explanation how the resource plan helps the utility achieve the greenhouse gas reduction goals, renewable energy standard, and solar energy standard as listed in the above-referenced legislation. Parties should also be prepared to discuss the matter in comments.

OTP discusses the Greenhouse Gas Reduction Goal in section 5.5 of its IRP. Figure 5-10 on page 5-9 shows Otter Tail's projected tons of CO_2 emissions per year for Company-owned units. Figure 5-12 on page 5-10 of the Company's IRP provides a good graphic analysis of how the Company's owned units, and also how the Company's owned units plus purchases compare to the Company's 2005 CO_2 emissions and to the Minnesota greenhouse gas reduction goal OTP's figure shows that the CO_2 emissions from Otter Tail's owned and purchased generation is projected to be below 2005 CO_2 emission levels for most, but not all, of the planning period.

To improve the record regarding the State's greenhouse gas reduction goal, the Department sent the Company DOC IR No. 1 asking the following two questions:

a. Given Otter Tail's preferred plan, what will be the percentage change in the Association's CO_2 emissions, comparing Otter Tail's estimated 2015 CO_2 emissions to its 2005 CO_2 emissions?

b. Given Otter Tail's preferred plan, what will be the percentage change in the Company's CO_2 emissions, comparing Otter Tail's estimated 2025 CO_2 emissions to its 2005 CO_2 emissions?

The Department sent similar information requests to Southern Minnesota Municipal Power Agency in Docket No. ET9/RP-13-1104 and to Minnesota Municipal Power Agency in Docket No. ET6133/RP-13-1165. The Department appreciates the conversations with all three utilities on how to best present this information in a useful manner. Based on these discussions, the Department recommended that each utility calculate its CO_2 emissions the following approach:

- Start with emissions from utility-owned generation;
- Add emissions from utility purchases; and
- Subtract CO_2 emissions from sales from utility-owned generation[22].

Since the emissions from utility purchases is unknown (unless a bilateral contract exists), the Department recommended that utilities use the 2005 average emissions per MWh for the Midwest Reliability Organization (MRO) West region 2005 purchases, and the 2009 average emissions per MWh for the MRO West region for 2015 and 2025.

Table 16 below provides a summary of Otter Tail's reduction in CO_2 emissions, under OTP's preferred plan, that the Department calculated using Otter Tail's response to the Department's request.

[22] In general, Otter Tail followed this methodology in its original IRP analysis.

Table 16: Comparing Otter Tail's Projected 2015 and 2025 CO_2 Emissions to 2005 CO_2 Emissions

	Energy Production (MWh)	CO_2 Emissions (Tons CO_2)	% Reduction From 2005 Emissions	Lbs of CO_2 per MWh	Percentage Reduction in CO_2 Emission Intensity From 2005
2005	4,393,148	4,653,930		2,119	
2015	4,972,900	4,250,551	9%	1,709	19%
2025	5,314,900	4,388,417	6%	1,651	22%

As shown in Table 16, under OTP's preferred plan, Otter Tail's 2015 CO_2 emissions are projected to decline by 9 percent when compared to 2005 emissions. By 2025, however, total CO_2 emissions are expected to rise from 2015 levels so that Otter Tail's projected CO_2 emissions would be only be six percent lower than 2005 emission levels.

Otter Tail stated in its response to DOC IR No 1:

> Otter Tail's 2013 IRP modeled market opportunity purchases using the most recent MRO regional average CO_2/MWh of 1,623.64 based on the year 2009. From 2005 to 2009 the average CO_2/MWh for the MRO has dropped 10.9%. Otter Tail expects this regional average to continue to decline over time but did not model any decline for the study period (2014 to 2028).

The Department agrees with Otter Tail's conclusion that CO_2/MWh will likely decline over time. The Department notes that in its response to a similar information request, SMMPA provided two scenario analyses based on two different assumptions as to how much the average MISO CO_2 emissions will decline. In one scenario SMMPA assumed that the stipulated emission rate for purchases in the analysis of 1,822 lbs/MWH of CO_2, will decrease by 1 percent annually between 2005 and the forecast years of 2015 and 2025. In a second scenario, SMMPA assumed that that the stipulated emission rate for purchases in the analysis of 1,822 lbs/MWH of CO_2 will decline at the rates that SMMPA forecasts for its own generation. The Department has requested that parties submit comments on the best way to estimate electric utilities' expected compliance with the greenhouse gas reduction goal in SMMPA's IRP Docket. This information may help the Commission identify a specific methodology to be used in IRPs. At that time, OTP can update its estimates as needed.

X. 50 AND 75 PERCENT RENEWABLE AND CONSERVATION GOAL

Minnesota Statutes 216B.2422, Subd. 2, states that “a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.” Although the statute refers to capacity needs, the Commission has measured compliance by comparing the energy from future conservation and renewable resources with the total grown in a utility’s energy requirements.

Otter Tail projects that its new Minnesota energy requirements will increase by 827 GWh over the planning period. In addition, the Company projects that its 1.5 percent Minnesota energy savings goal will contribute 540 GWh towards the Company’s new Minnesota energy requirement, or 65 percent of the new requirement. Further, the Company calculates that adding a 50 MW wind generation unit would produce a resource plan that would provide 75 percent of the Company’s new Minnesota energy requirement through renewables and conservation.

The Department notes that our proposal for 1.7 percent conservation would improve OTP’s performance in this regard.

III. DEPARTMENT RECOMMENDATIONS

A. FORECAST

The Department asks that in Reply Comments, the Company include the following:

- A full explanation and justification of why the Company uses base 55 HDD data in its IRP analysis instead of the more commonly used base 65 HDD data;
- A full explanation of what steps and analysis the Company conducted to verify that the weather interaction term did not impair the estimative power and stability of regression models;
- A detailed explanation, including data if available, which supports a change in weather, or weather’s impact on energy consumption, as suggested by the specification of the Company’s weather interaction variables;
- Clarification of whether the Company’s method to estimate coincident peak is based on recommendations, or suggestions, from MISO;
- its coincident peak analysis originally provided in its response to DOC Information Request No. 4 updated with 2012 and 2013 data;
- a detailed discussion regarding whether the Company believes creation of a dataset representative of historical MISO conditions is possible, from Otter Tail’s perspective, and whether the Company would be amenable to participating in this type of analysis with MISO;

- A detailed discussion of how MISO dispatches demand response and what, if any, say Otter Tail has on the deployment of these resources on a non-coincident, either summer or winter;
- Historical demand response deployment, by day, over the period since Otter Tail registered load management with MISO;
- Historical demand response deployment, by day, for the five-year period before Otter Tail registered load management with MISO; and
- A detailed discussion of how much demand response Otter Tail believes MISO will have available, in the future, to account for the Company's non-coincident peak.

B. DSM

The Department recommends that the Commission approve a resource planning DSM goal of 1.7 percent of retail sales.

C. MODELING/ACTION PLAN

The Department recommends that the Commission require Otter Tail to:

a. use Strategist in the Company's next IRP;
b. include, in all future IRPs, a forecast of the market cost of SO_2 allowances, as well as any other emissions allowances granted to the Company;
c. include an analysis of the effects of retiring its Jamestown and Lake Preston peaking units in its next IRP; and
d. modify Otter Tail's plan to include 1.7 percent DSM; 100 MW of wind and a 50 MW gas CT in 2017; and 100 MW of wind, a 200 MW CT, and 21 MW of solar in 2019.

D. ENVIRONMENTAL ISSUES

The Department recommends that the Commission find that OTP is adequately tracking environmental regulations that might impact its operations. The Department requests that OTP report in its Reply Comments on how the Supreme Court's ruling on EPA's CSAPR may affect OTP's resource plan.

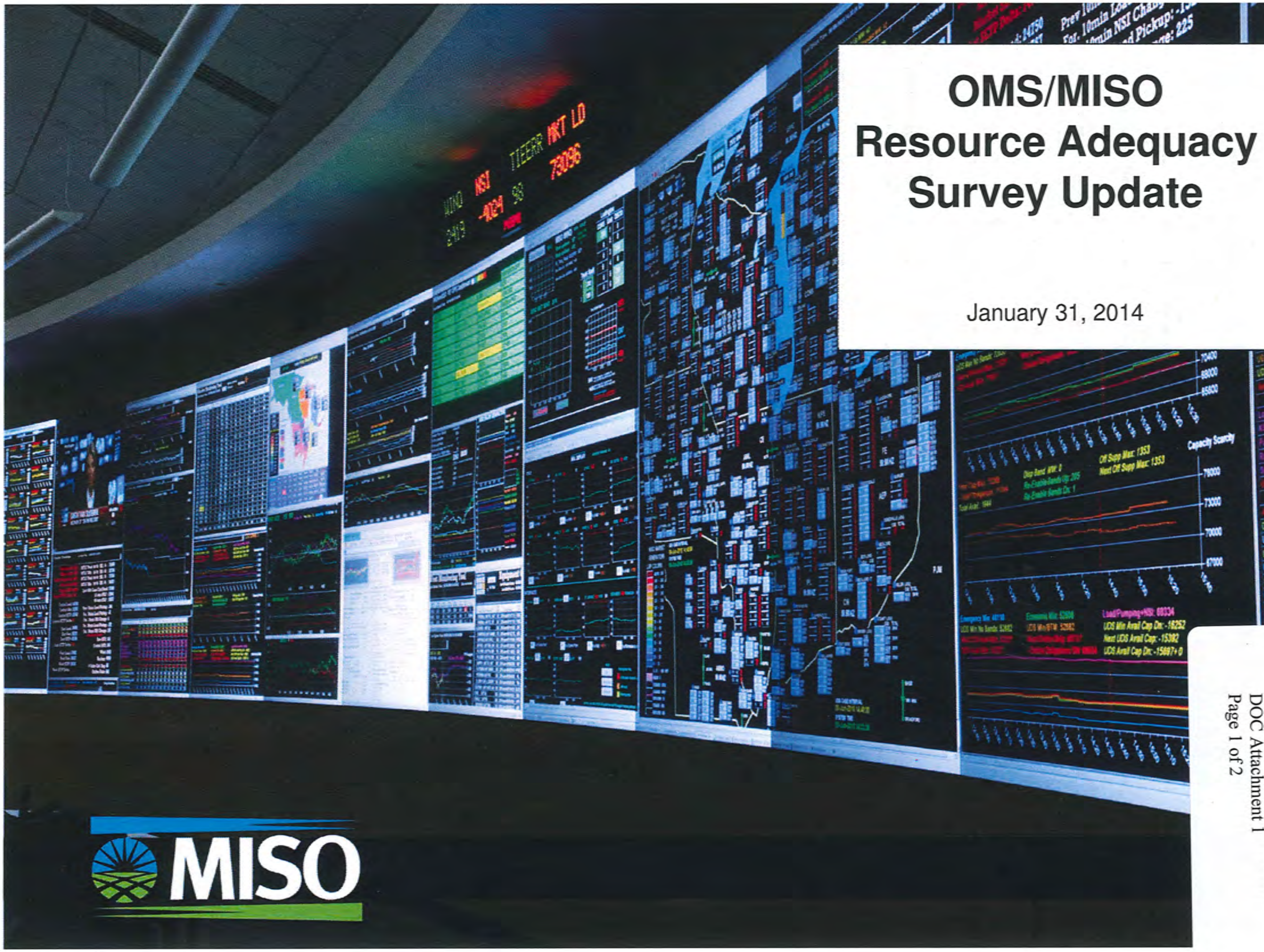
E. GREENHOUSE GAS REDUCTION GOAL

The Department recommends that the Commission require Otter Tail to provide an updated estimate of its compliance with Minnesota's greenhouse gas reduction goal once the Commission approves a specific way of estimating compliance.

/sm

OMS/MISO Resource Adequacy Survey Update

January 31, 2014

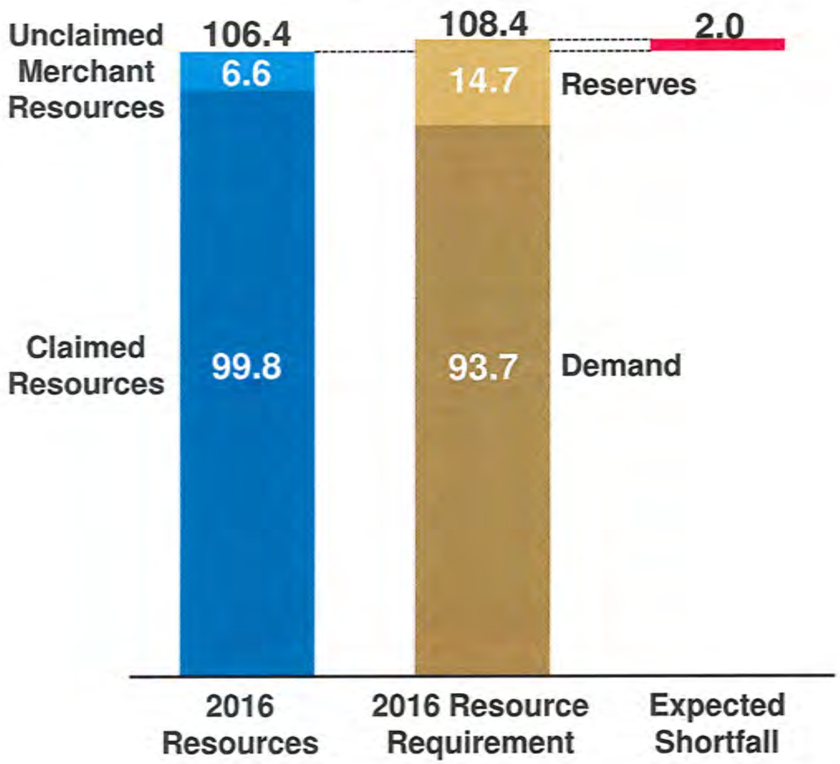


MISO

OMS / MISO Resource Adequacy Survey Results - As of January 31, 2014

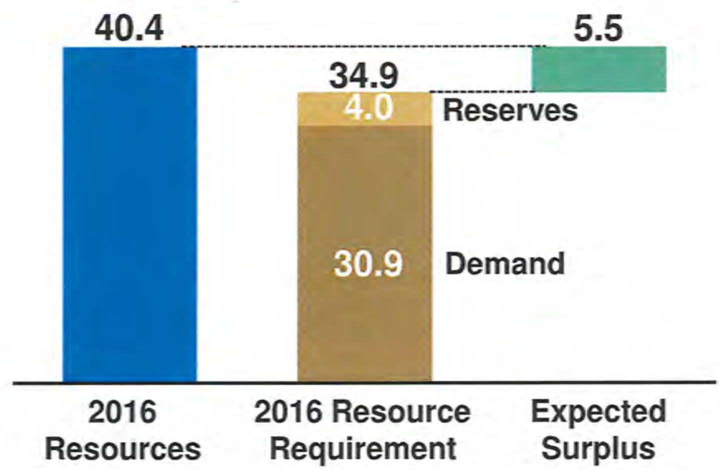
Central & North Regions

In GW



South Region

In GW



Notes: Current system conditions (including capacity trapped both inter- and intra-regionally) would limit capacity available for transfer from the South Region – currently estimated at 1.5 to 3.0 GW.

Summary of PVSC's of Top Ranked Expansion Plans

	Contingency	Scenario 1 Non-Coincident Peak		Scenario 2 Coincident Peak		Scenario 3 Coincident Peak with Half Diversity Factor		Scenario 4 Non-Coincident Peak No Superfluous Wind		Scenario 5 Non-Coincident Peak Retire Oil Peakers		Scenario 6 Non-Coincident Peak Full Market Access	
		PVSC ($000s)	% Diff from Scen. 1 Contingency 0	PVSC ($000s)	% Diff from Scen. 1	PVSC ($000s)	% Diff from Scen. 1	PVSC ($000s)	% Diff from Scen. 1	PVSC ($000s)	% Diff from Scen. 1	PVSC ($000s)	% Diff from Scen. 1
		[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]
0	Base	3,971,851	0.00%	3,953,386	-0.46%	3,954,557	-0.44%	4,038,075	1.67%	3,961,691	-0.26%	3,890,412	-2.05%
1	Market Price - OTP Forecast - 20%	3,949,690	-0.56%	3,934,535	-0.38%	3,935,474	-0.36%	4,019,892	1.78%	3,943,847	-0.15%	3,838,795	-2.81%
2	Market Price - OTP Forecast + 20%	3,977,906	0.15%	3,965,001	-0.32%	3,966,411	-0.29%	4,048,235	1.77%	3,972,349	-0.14%	3,908,173	-1.75%
3	Market Price - OTP Forecast + 40%	3,983,913	0.30%	3,972,123	-0.30%	3,973,782	-0.25%	4,052,959	1.73%	3,978,499	-0.14%	3,912,232	-1.80%
4	Market Price - OTP Forecast + 60%	3,987,750	0.40%	3,976,978	-0.27%	3,978,890	-0.22%	4,055,617	1.70%	3,982,478	-0.13%	3,914,057	-1.85%
5	Carbon cost in 2017 - high ($34) w high ext	4,501,610	13.34%	4,489,648	-0.27%	4,490,799	-0.24%	4,614,202	2.50%	4,495,196	-0.14%	4,486,388	-0.34%
6	Carbon cost in 2017 - low ($9) w low ext	3,390,285	-14.64%	3,377,225	-0.39%	3,378,403	-0.35%	3,422,819	0.96%	3,384,585	-0.17%	3,274,137	-3.43%
7	Carbon cost in 2019 - mid ($21.50) w high ext	3,787,234	-4.65%	3,774,782	-0.33%	3,775,952	-0.30%	3,844,153	1.50%	3,781,534	-0.15%	3,704,922	-2.17%
8	Carbon cost in 2019 - high ($34) w high ext	4,210,744	6.01%	4,200,940	-0.23%	4,202,092	-0.21%	4,299,396	2.11%	4,204,331	-0.15%	4,185,047	-0.61%
9	Carbon cost in 2019 - low ($9) w low ext	3,314,173	-16.56%	3,301,386	-0.39%	3,302,564	-0.35%	3,341,269	0.82%	3,308,473	-0.17%	3,197,685	-3.51%
10	Gas - OTP Forecast - $1	3,918,963	-1.33%	3,905,177	-0.35%	3,906,380	-0.32%	3,978,376	1.52%	3,913,263	-0.15%	3,872,100	-1.20%
11	Gas - OTP Forecast + $1.0	4,003,158	0.79%	3,991,868	-0.28%	3,993,016	-0.25%	4,085,826	2.07%	3,996,744	-0.16%	3,903,056	-2.50%
12	Gas - OTP Forecast + $2.0	4,041,861	1.76%	4,033,752	-0.20%	4,034,918	-0.17%	4,134,841	2.30%	4,035,447	-0.16%	3,915,154	-3.13%
13	Gas - OTP Forecast + $3.0	4,080,422	2.73%	4,072,132	-0.20%	4,073,297	-0.17%	4,182,532	2.50%	4,074,008	-0.16%	3,925,252	-3.80%
14	Gas - OTP Forecast + $4.0	4,119,022	3.71%	4,110,599	-0.20%	4,111,732	-0.18%	4,230,255	2.70%	4,112,608	-0.16%	3,934,341	-4.48%
15	Gas - OTP Forecast + $5.0	4,157,494	4.67%	4,148,918	-0.21%	4,150,051	-0.18%	4,277,833	2.89%	4,151,080	-0.15%	3,942,152	-5.18%
16	Coal - OTP Forecast - 25%	4,219,266	6.23%	4,204,623	-0.35%	4,205,786	-0.32%	4,300,792	1.93%	4,213,566	-0.14%	4,132,010	-2.07%
17	Coal - OTP Forecast + 25%	3,707,152	-6.66%	3,693,829	-0.36%	3,695,013	-0.33%	3,766,577	1.60%	3,701,452	-0.15%	3,635,508	-1.93%
18	Load Growth - High	4,379,667	10.27%	4,363,749	-0.36%	4,369,279	-0.24%	4,479,444	2.28%	4,373,254	-0.15%	4,341,052	-0.88%
19	Load Growth - Low	3,563,789	-10.27%	3,590,703	0.76%	3,563,739	0.00%	3,685,696	3.42%	3,558,705	-0.14%	3,536,528	-0.76%
20	Wind - $30/MWh	3,843,029	-3.24%	3,829,026	-0.36%	3,830,195	-0.33%	3,962,548	3.11%	3,837,329	-0.15%	3,729,009	-2.97%
21	Wind - $35/MWh	3,881,509	-2.27%	3,867,505	-0.36%	3,868,675	-0.33%	3,984,598	2.66%	3,875,809	-0.15%	3,782,810	-2.54%
22	Wind - $40/MWh	3,924,450	-1.19%	3,910,446	-0.36%	3,911,616	-0.33%	4,011,336	2.21%	3,918,750	-0.15%	3,836,611	-2.24%
23	Wind - $50/MWh	4,010,332	0.97%	3,996,327	-0.35%	3,997,497	-0.32%	4,064,813	1.36%	4,004,632	-0.14%	3,944,214	-1.65%
24	Wind - $55/MWh	4,053,273	2.05%	4,039,268	-0.35%	4,040,438	-0.32%	4,091,552	0.94%	4,047,572	-0.14%	3,998,015	-1.36%
25	Wind - $60/MWh	4,096,213	3.13%	4,080,732	-0.38%	4,081,902	-0.35%	4,118,290	0.54%	4,090,513	-0.14%	4,051,816	-1.08%
26	Wind - $65/MWh	4,129,396	3.97%	4,109,837	-0.47%	4,111,007	-0.45%	4,142,471	0.32%	4,122,982	-0.16%	4,095,845	-0.81%
27	Wind - $70/MWh	4,153,312	4.57%	4,127,669	-0.62%	4,130,730	-0.54%	4,156,730	0.08%	4,148,967	-0.10%	4,112,251	-0.99%
28	Wind - $75/MWh	4,166,558	4.90%	4,141,926	-0.59%	4,146,933	-0.47%	4,170,987	0.11%	4,161,476	-0.12%	4,120,419	-1.11%
29	Wind - $80/MWh	4,179,039	5.22%	4,156,184	-0.55%	4,163,135	-0.38%	4,180,602	0.04%	4,173,956	-0.12%	4,120,419	-1.40%
30	Solar - $133/MWh - with min	4,002,679	0.78%	3,988,632	-0.35%	3,989,771	-0.32%	4,100,849	2.45%	3,996,265	-0.16%	3,949,208	-1.34%
31	Solar -$75/MWh - no min	3,975,779	0.10%	3,961,732	-0.35%	3,962,782	-0.33%	4,073,949	2.47%	3,969,365	-0.16%	3,890,412	-2.15%
32	Solar -$75/MWh - with min	3,967,391	-0.11%	3,953,386	-0.35%	3,954,557	-0.32%	4,038,075	1.78%	3,961,691	-0.14%	3,922,308	-1.14%
33	Solar -$150/MWh - with min	4,015,003	1.09%	4,000,957	-0.35%	4,002,095	-0.32%	4,113,205	2.45%	4,008,589	-0.16%	3,957,093	-1.44%
34	Capital Cost - Low	3,881,964	-2.26%	3,870,612	-0.29%	3,871,781	-0.26%	3,948,179	1.71%	3,875,551	-0.17%	3,833,628	-1.25%
35	Capital Cost - High	4,057,852	2.17%	4,039,860	-0.44%	4,041,029	-0.41%	4,135,297	1.91%	4,052,152	-0.14%	3,947,197	-2.73%
36	CO2 Reduction Goal	3,863,550	-2.73%	3,863,604	0.00%	3,863,550	0.00%	3,943,887	2.08%	3,857,136	-0.17%	3,804,857	-1.52%

Scenario 1: Non-Coincident Peak
Top Ranked Expansion Plans from Each Contingency

		0 Base	1 Market Price - OTP Forecast - 20%	2 Market Price - OTP Forecast + 20%	3 Market Price - OTP Forecast + 40%	4 Market Price - OTP Forecast + 60%	5 Carbon cost in 2017 - high ($34) w high ext	6 Carbon cost in 2017 - low ($9) w low ext	7 Carbon cost in 2019 - mid ($21.50) w high ext	8 Carbon cost in 2019 - high ($34) w high ext	9 Carbon cost in 2019 - low ($9) w low ext	10 Gas - OTP Forecast - $1	11 Gas - OTP Forecast + $1.0	12 Gas - OTP Forecast + $2.0	13 Gas - OTP Forecast + $3.0	14 Gas - OTP Forecast + $4.0	15 Gas - OTP Forecast + $5.0	16 Coal - OTP Forecast - 25%	17 Coal - OTP Forecast + 25%	18 Load Growth - High	19 Load Growth - Low	20 Wind - $30/MWh	21 Wind - $35/MWh	22 Wind - $40/MWh	23 Wind - $50/MWh	24 Wind - $55/MWh	25 Wind - $60/MWh	26 Wind - $65/MWh	27 Wind - $70/MWh	28 Wind - $75/MWh	29 Wind - $80/MWh	30 Solar - $133/MWh - with min	31 Solar - $75/MWh - no min	32 Solar - $75/MWh - with min	33 Solar - $150/MWh - with min	34 Capital Cost - Low	35 Capital Cost - High	36 CO2 Reduction Goal
Wind 100 MW	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Wind 100 MW	2017	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	1	1	1	1	1	1	1
Wind 100 MW	2019	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	-	-	1	1	1	1	1	1	1
Wind 100 MW	2021	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	1	1	1	1	1	1	1	1
Wind 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind 100 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind 100 MW	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	21	21	-	-	-
Solar 1 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2019	1	1	1	1	1	-	1	1	-	1	1	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	1
CT 200 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comb. Heat & Power	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 2 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 3 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2017	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-
CT 50 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2019	-	-	-	-	-	1	-	-	1	-	-	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
CT 50 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	-	-	-	-	-	-	-
CT 50 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
CT 50 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2024	1	1	1	1	1	-	1	1	-	1	1	-	-	-	-	-	1	1	-	-	1	1	1	1	1	1	-	-	-	-	1	1	1	1	-	1	-
CT 50 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2019	-	-	-	-	-	1	-	-	1	-	-	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
CT 100 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2021	-	-	-	-	-	1	-	-	1	-	-	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
CT 100 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Note: Green shading indicates the addition of a unit that is *not* included in the base contingency. Red shading indicates the elimination of a unit, relative to the base contingency.

Scenario 2: Coincident Peak
Top Ranked Expansion Plans from Each Contingency

		0 Base	1 Market Price - OTP Forecast - 20%	2 Market Price - OTP Forecast + 20%	3 Market Price - OTP Forecast + 40%	4 Market Price - OTP Forecast + 60%	5 Carbon cost in 2017 - high ($34) w high ext	6 Carbon cost in 2017 - low ($9) w low ext	7 Carbon cost in 2019 - mid ($21.50) w high ext	8 Carbon cost in 2019 - high ($34) w high ext	9 Carbon cost in 2019 - low ($9) w low ext	10 Gas - OTP Forecast - $1	11 Gas - OTP Forecast + $1.0	12 Gas - OTP Forecast + $2.0	13 Gas - OTP Forecast + $3.0	14 Gas - OTP Forecast + $4.0	15 Gas - OTP Forecast + $5.0	16 Coal - OTP Forecast - 25%	17 Coal - OTP Forecast + 25%	18 Load Growth - High	19 Load Growth - Low	20 Wind - $30/MWh	21 Wind - $35/MWh	22 Wind - $40/MWh	23 Wind - $50/MWh	24 Wind - $55/MWh	25 Wind - $60/MWh	26 Wind - $65/MWh	27 Wind - $70/MWh	28 Wind - $75/MWh	29 Wind - $80/MWh	30 Solar - $133/MWh - with min	31 Solar -$75/MWh - no min	32 Solar -$75/MWh - with min	33 Solar -$150/MWh - with min	34 Capital Cost - Low	35 Capital Cost - High	36 CO2 Reduction Goal
Wind 100 MW	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Wind 100 MW	2017	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	1	1	1	1	1	1	1
Wind 100 MW	2019	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	1	1	1	1	1	1	1	1	1
Wind 100 MW	2021	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	-	-	-	1	1	1	1	1	1	1
Wind 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind 100 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind 100 MW	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	21	21	-	-	-
Solar 1 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2019	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	1	1	1	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
CT 200 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comb. Heat & Power	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 2 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 3 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	2	2	2	2	-	-	3	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2021	1	1	1	1	1	-	1	1	-	1	1	1	-	-	-	-	1	1	-	1	1	1	1	1	1	-	-	-	-	-	1	1	1	1	-	1	-
CT 50 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
CT 50 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2024	1	1	1	1	1	-	1	1	-	1	1	1	-	-	-	-	1	1	-	-	1	1	1	1	1	-	-	-	-	-	1	1	1	1	-	1	-
CT 50 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2021	-	-	-	-	-	1	-	-	1	-	-	-	1	1	1	1	-	-	1	1	-	-	-	-	-	1	1	1	1	1	-	-	-	-	1	-	-
CT 100 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Note: Green shading indicates the addition of a unit that is *not* included in the base contingency. Red shading indicates the elimination of a unit, relative to the base contingency.

Scenario 3: 50DF (Coincident Peak - Half of Otter Tail's Assumed Diversity Factor)
Top Ranked Expansion Plans from Each Contingency

		0 Base	1 Market Price - OTP Forecast - 20%	2 Market Price - OTP Forecast + 20%	3 Market Price - OTP Forecast + 40%	4 Market Price - OTP Forecast + 60%	5 Carbon cost in 2017 - high ($34) w high ext	6 Carbon cost in 2017 - low ($9) w low ext	7 Carbon cost in 2019 - mid ($21.50) w high ext	8 Carbon cost in 2019 - high ($34) w high ext	9 Carbon cost in 2019 - low ($9) w low ext	10 Gas - OTP Forecast - $1	11 Gas - OTP Forecast + $1.0	12 Gas - OTP Forecast + $2.0	13 Gas - OTP Forecast + $3.0	14 Gas - OTP Forecast + $4.0	15 Gas - OTP Forecast + $5.0	16 Coal - OTP Forecast - 25%	17 Coal - OTP Forecast + 25%	18 Load Growth - High	19 Load Growth - Low	20 Wind - $30/MWh	21 Wind - $35/MWh	22 Wind - $40/MWh	23 Wind - $50/MWh	24 Wind - $55/MWh	25 Wind - $60/MWh	26 Wind - $65/MWh	27 Wind - $70/MWh	28 Wind - $75/MWh	29 Wind - $80/MWh	30 Solar - $133/MWh - with min	31 Solar - $75/MWh - no min	32 Solar - $75/MWh - with min	33 Solar - $150/MWh - with min	34 Capital Cost - Low	35 Capital Cost - High	36 CO2 Reduction Goal
Wind 100 MW	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Wind 100 MW	2017	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Wind 100 MW	2019	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	1	1	1	1	1	1	1
Wind 100 MW	2021	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	-	-	-	1	1	1	1	1	1	1
Wind 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind 100 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind 100 MW	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-
Solar 1 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	11	21	-	-	-
Solar 1 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2019	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
CT 200 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comb. Heat & Power	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 2 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 3 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2021	1	1	1	1	1	-	1	1	-	1	1	1	-	-	-	-	1	1	-	-	1	1	1	1	1	-	-	-	-	-	1	1	1	1	-	1	-
CT 50 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
CT 50 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2024	1	1	1	1	1	-	1	1	-	1	1	1	-	-	-	-	1	1	-	-	1	1	1	1	1	-	-	-	-	-	1	1	1	1	-	1	-
CT 50 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2021	-	-	-	-	-	1	-	-	1	-	-	-	1	1	1	1	-	-	1	-	-	-	-	-	-	1	1	1	1	1	-	-	-	-	1	-	-
CT 100 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Note: Green shading indicates the addition of a unit that is *not* included in the base contingency. Red shading indicates the elimination of a unit, relative to the base contingency.

Scenario 4: Non-Coincident Peak with No Superfluous Wind/Solar
Top Ranked Expansion Plans from Each Contingency

		0 Base	1 Market Price - OTP Forecast - 20%	2 Market Price - OTP Forecast + 20%	3 Market Price - OTP Forecast + 40%	4 Market Price - OTP Forecast + 60%	5 Carbon cost in 2017 - high ($34) w high ext	6 Carbon cost in 2017 - low ($9) w low ext	7 Carbon cost in 2019 - mid ($21.50) w high ext	8 Carbon cost in 2019 - high ($34) w high ext	9 Carbon cost in 2019 - low ($9) w low ext	10 Gas - OTP Forecast - $1	11 Gas - OTP Forecast + $1.0	12 Gas - OTP Forecast + $2.0	13 Gas - OTP Forecast + $3.0	14 Gas - OTP Forecast + $4.0	15 Gas - OTP Forecast + $5.0	16 Coal - OTP Forecast - 25%	17 Coal - OTP Forecast + 25%	18 Load Growth - High	19 Load Growth - Low	20 Wind - $30/MWh	21 Wind - $35/MWh	22 Wind - $40/MWh	23 Wind - $50/MWh	24 Wind - $55/MWh	25 Wind - $60/MWh	26 Wind - $65/MWh	27 Wind - $70/MWh	28 Wind - $75/MWh	29 Wind - $80/MWh	30 Solar - $133/MWh - with min	31 Solar - $75/MWh - no min	32 Solar - $75/MWh - with min	33 Solar - $150/MWh - with min	34 Capital Cost - Low	35 Capital Cost - High	36 CO2 Reduction Goal
Wind 100 MW	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2
Wind 100 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
Wind 100 MW	2019	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	1	1	1	1	1	-
Wind 100 MW	2021	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	1	1	1	1	1	1	-
Wind 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind 100 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
Wind 100 MW	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	21	21	-	-	-
Solar 1 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2017	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	1	1	-	-	1	1	1	1	1	1	1	1	1	-	-	1	-	-	-	1	-
CT 200 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-
CT 200 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comb. Heat & Power	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1	-	1	1	-	-	-
Hoot Lake 2 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 3 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	1	1	1	-	-
CT 50 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	-	-	1	1	-	-	-	-	-	-	-	-	-	-	1	-	1	1	1	-	1
CT 50 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2021	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	1	1	2	2	1	1	1	1	1	1	-	-	-	-	-	1	-	-	-	1	1
CT 50 MW	2022	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	1	1	1	1	1	1	1	1	1	1	-	-	-	-	1	1	1	1	-	1	-
CT 50 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
CT 50 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1
CT 100 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2021	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	-	1	1	1	-	1
CT 100 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Note: Green shading indicates the addition of a unit that is *not* included in the base contingency. Red shading indicates the elimination of a unit, relative to the base contingency.

Scenario 5: Non-Coincident Peak and Retire Oil Peakers
Top Ranked Expansion Plans from Each Contingency

		0 Base	1 Market Price - OTP Forecast - 20%	2 Market Price - OTP Forecast + 20%	3 Market Price - OTP Forecast + 40%	4 Market Price - OTP Forecast + 60%	5 Carbon cost in 2017 - high ($34) w high ext	6 Carbon cost in 2017 - low ($9) w low ext	7 Carbon cost in 2019 - mid ($21.50) w high ext	8 Carbon cost in 2019 - high ($34) w high ext	9 Carbon cost in 2019 - low ($9) w low ext	10 Gas - OTP Forecast - $1	11 Gas - OTP Forecast + $1.0	12 Gas - OTP Forecast + $2.0	13 Gas - OTP Forecast + $3.0	14 Gas - OTP Forecast + $4.0	15 Gas - OTP Forecast + $5.0	16 Coal - OTP Forecast - 25%	17 Coal - OTP Forecast + 25%	18 Load Growth - High	19 Load Growth - Low	20 Wind - $30/MWh	21 Wind - $35/MWh	22 Wind - $40/MWh	23 Wind - $50/MWh	24 Wind - $55/MWh	25 Wind - $60/MWh	26 Wind - $65/MWh	27 Wind - $70/MWh	28 Wind - $75/MWh	29 Wind - $80/MWh	30 Solar - $133/MWh - with min	31 Solar - $75/MWh - no min	32 Solar - $75/MWh - with min	33 Solar - $150/MWh - with min	34 Capital Cost - Low	35 Capital Cost - High	36 CO2 Reduction Goal
Wind 100 MW	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Wind 100 MW	2017	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	1	1	1	1	1	1	1
Wind 100 MW	2019	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	-	-	1	1	1	1	1	1	1
Wind 100 MW	2021	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	1	1	1	1	1	1	1	1
Wind 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind 100 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind 100 MW	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	21	21	-	-	-
Solar 1 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2019	1	1	1	1	1	-	1	1	-	1	1	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	1
CT 200 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comb. Heat & Power	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 2 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 3 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2017	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	1	1	1	1	1	1	1	-	-	-	1	1	1	1	1	1	-
CT 50 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2019	-	-	-	-	-	1	-	-	1	-	-	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
CT 50 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
CT 50 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2024	1	1	1	1	1	-	1	1	-	1	1	-	-	-	-	-	1	1	-	-	1	1	1	1	1	1	-	-	-	-	1	1	1	1	-	1	-
CT 50 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1	1	1	-	-	-	-	-	-	-
CT 100 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2019	-	-	-	-	-	1	-	-	1	-	-	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
CT 100 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2021	-	-	-	-	-	1	-	-	1	-	-	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
CT 100 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Note: Green shading indicates the addition of a unit that is *not* included in the base contingency. Red shading indicates the elimination of a unit, relative to the base contingency.

Scenario 6: Non-Coincident Peak with Full Market Throughout Study Period
Top Ranked Expansion Plans from Each Contingency

Unit	Year	0 Base	1 Market Price - OTP Forecast - 20%	2 Market Price - OTP Forecast + 20%	3 Market Price - OTP Forecast + 40%	4 Market Price - OTP Forecast + 60%	5 Carbon cost in 2017 - high ($34) w high ext	6 Carbon cost in 2017 - low ($9) w low ext	7 Carbon cost in 2019 - mid ($21.50) w high ext	8 Carbon cost in 2019 - high ($34) w high ext	9 Carbon cost in 2019 - low ($9) w low ext	10 Gas - OTP Forecast - $1	11 Gas - OTP Forecast + $1.0	12 Gas - OTP Forecast + $2.0	13 Gas - OTP Forecast + $3.0	14 Gas - OTP Forecast + $4.0	15 Gas - OTP Forecast + $5.0	16 Coal - OTP Forecast - 25%	17 Coal - OTP Forecast + 25%	18 Load Growth - High	19 Load Growth - Low	20 Wind - $30/MWh	21 Wind - $35/MWh	22 Wind - $40/MWh	23 Wind - $50/MWh	24 Wind - $55/MWh	25 Wind - $60/MWh	26 Wind - $65/MWh	27 Wind - $70/MWh	28 Wind - $75/MWh	29 Wind - $80/MWh	30 Solar - $133/MWh - with min	31 Solar - $75/MWh - no min	32 Solar - $75/MWh - with min	33 Solar - $150/MWh - with min	34 Capital Cost - Low	35 Capital Cost - High	36 CO2 Reduction Goal
Wind 100 MW	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
Wind 100 MW	2017	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	1	1	1	1	1	1	1
Wind 100 MW	2019	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	-	-	1	1	1	1	1	1	1
Wind 100 MW	2021	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	1	1	1	1	1	1	1
Wind 100 MW	2023	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	1	1	1	1	1	1	-	-	-	-	-	1	-	-	1	1	1
Wind 100 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind 100 MW	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	21	21	-	-	-
Solar 1 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar 1 MW	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 200 MW	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	-	-	-	-	-	-	-
CT 200 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comb. Heat & Power	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 2 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hoot Lake 3 Conv.	2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2017	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-
CT 50 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2021	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	1	1	1	1	1	1	-	-	-	-	1	1	1	1	1	1	1
CT 50 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 50 MW	2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2021	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	1	1	1	1	1	1	1	-	-	-	-	1	1	1	1	1	1	1
CT 100 MW	2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT 100 MW	2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Note: Green shading indicates the addition of a unit that is *not* included in the base contingency. Red shading indicates the elimination of a unit, relative to the base contingency.

CERTIFICATE OF SERVICE

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

Comments of the Minnesota Department of Commerce, Division of Energy Resources

Docket No. E017/RP-13-961

Dated this 2nd day of May 2014

/s/Jan Mottaz

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