MINNESOTA DEPARTMENT OF COMMERCE

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August 29, 2014

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

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

Dear Dr. Haar:

Attached are the supplemental 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 Department **recommends approval with modifications.** 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/lt
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

DOCKET NO. E017/RP-13-961

I. INTRODUCTION

On May 2, 2014 Environmental Intervenors and the Minnesota Department of Commerce, Division of Energy Resources (the Department) submitted initial comments on Otter Tail Power Company's (OTP or the Company's) 2013 Integrated Resource Plan (IRP). The Department's recommendations included the following:

A. FORECAST

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

1. 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;
2. 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;
3. A detailed explanation, including data if available, to support a change in weather, or weather's impact on energy consumption, as suggested by the specification of the Company's weather interaction variables;
4. Clarification of whether the Company's method to estimate coincident peak was based on recommendations, or suggestions, from the Midcontinent Independent System Operator (MISO);
5. OTP's coincident peak analysis originally provided in its response to DOC Information Request No. 4 updated with 2012 and 2013 data;
6. 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;

7. A detailed discussion of how MISO dispatches demand response and what, if any, say Otter Tail has on the deployment of these resources during non-coincident periods, either summer or winter;
8. Historical demand response deployment, by day, over the period since Otter Tail registered load management with MISO;
9. Historical demand response deployment, by day, for the five-year period before Otter Tail registered load management with MISO; and
10. 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 recommended that the Commission approve a resource planning DSM goal of 1.7 percent of retail sales.

C. MODELING/ACTION PLAN

The Department recommended 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

At the time the Department filed its comments, prior to the release of the Environmental Protection Agency's draft carbon rules, the Department recommended that the Commission find that OTP was adequately tracking environmental regulations that might impact its operations. The Department requested that OTP report in its Reply Comments on how the Supreme Court's ruling on EPA's cross-state air pollution rule (CSAPR) may affect OTP's resource plan.

E. GREENHOUSE GAS REDUCTION GOAL

The Department recommended 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.

On July 18, 2014, the Commission issued a Notice of Extended Comment Period at OTP's request. The Commission's Notice maintained a Reply Comment deadline of August 1, 2014 but also created the opportunity for the submission of Supplemental Comments with a deadline of August 29, 2014.

On August 1, 2014, Otter Tail, Environmental Intervenors, and the MidContinent Independent System Operator submitted reply comments.

Below the Department provides its supplemental comments in response to the reply comments.

II. DEPARTMENT'S SUPPLEMENTAL COMMENTS

Otter Tail Power provided comments concerning the following issues:

11. Use of MISO Coincident Peak or Non-Coincident Peak transmission factors for planning generation needs.
12. Otter Tail's use of market energy in long-term planning.
13. The conservation goals that should be approved in the resource plan.
14. The Company's compliance with the State's renewable energy standard.
15. The amount of wind to be included in the resource plan.
16. Forecasting issues.

In addition, Environmental Intervenors raised the following issues:

17. The Department's preferred plan does not meet the State's greenhouse gas emissions reductions goals.
18. Otter Tail's analysis of solar resources makes meeting the Solar Energy Standard more costly that it would be.
19. Otter Tail's modeling of wind may be overestimating the price of new wind resources.

The Department discusses each of these issues below.

A. WHAT PEAK SHOULD BE USED FOR PLANNING PURPOSES

Ensuring that Minnesota utilities have an adequate supply of generation resources to maintain reliability is one of the Commission's most important roles. On page 2 of its Reply Comments, Otter Tail stated the following:

> Otter Tail disagrees with the Department's proposed modifications to its plan.
>
> Specifically, the Department incorrectly recommends [that] Otter Tail should build resources in excess of those required to meet its MISO resource adequacy requirements at a cost of approximately $112 million, based upon an apparent misunderstanding of how the MISO resource adequacy construct works.

The Department does not misunderstand how MISO's resource adequacy construct works; the Department understands that MISO's role is to protect the bulk transmission system, and that MISO defers to state commissions to determine the generation reserve requirements under the jurisdiction of those commissions. The Department is concerned that MISO's resource adequacy construct may not be sufficient to provide reliable service.

In particular, the Department has four concerns with Minnesota utilities using MISO's Coincident Peak as the parameter for the amount of resources that should be procured over the long term:

20. For several reasons, load-serving entities (LSEs) across the MISO footprint may not have sufficient resources to provide reliable service, resulting in an enormously expensive blackout.
21. MISO's resource adequacy standard has changed annually and MISO is planning more changes, making it difficult for utilities and regulators to know the long-term target.
22. The Department has concerns with the forecasting methods being used by LSEs across the MISO footprint to forecast each LSE's peak at MISO coincident peak based on the LSE's non-coincident peak.

Each of these concerns is discussed below.

1. Resource Adequacy

As the Commission is aware, enforcement of the EPA's Mercury Air Toxics (MATS) Rule for coal and oil powered electric generation plants, along with performance issues due to age, is expected to force the retirement of many coal-fired generation plants in the near future. MISO's analysis of the impact of the MATS rule and other forces (both on the supply side and the demand side) has fluctuated. For example, the June 5, 2014 MISO Resource Adequacy Forecast for 2016 showed an increase in the capacity shortfall in the MISO

Central and North region from 2.0 GW as of January 31, 2014 to 2.3 GW as of June 2, 2014, an increase of 300 MW. In addition, as the economy recovers, there has been and likely will continue to be a corresponding increase in electricity sales. Given both an unprecedented reduction in resources and an increase in demand, MISO could run the risk of not having adequate resources.

Because MISO's function is to protect the bulk transmission system, if the demand for electricity exceeds the supply of electricity at any point, MISO will deploy its emergency tools to protect the bulk transmission system, including shedding firm load:

> The MISO Reliability Coordinator and Balancing Authority Operator have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate Transmission System Emergencies. During normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include **shedding of firm load** to prevent or alleviate System Operating Limit or Interconnection Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel.
> (MISO's RTO-EOP-004-r14.1,[1] emphasis added)

The structure of MISO and its policies also increase the risk of inadequate resources in MISO. For example, under MISO, the capacity deficiency charge is based on the cost of new entry (CONE) based on the addition of a natural gas generation facility. There are several problems with this approach. This penalty approach does not reflect the reality of the significant time that is needed for new electric generation resources to become operational, including time to acquire facilities such as turbines, the availability of labor to install such facilities, the availability of natural gas resources and the time that may be needed to extend natural gas pipelines. That is, this approach does not ensure that electric service will be reliable if generation resources are not adequate in the MISO region to meet load.

In addition, such an approach would penalize the wrong people. Unless prevented by a regulatory agency, for example, penalties are generally passed on to end-users, who typically do not have the ability to add generation to the system. To provide the correct incentive, penalties should be charged only to the generation owners who failed to add sufficient generation to their systems. However, some utilities that are members of MISO operate in states in which generation facilities are deregulated. Generators in deregulated states not only cannot be held accountable for failing to add enough generation to their systems, they actually have a financial incentive not to add new generation because doing so would increase their potential for high revenues as energy prices spike due to limited availability of resources.

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[1] https://www.misoenergy.org/Library/Repository/Procedure/RTO-EOP-004-r14.1%20Transmission%20Emergencies%20Procedure.pdf

Unfortunately, it appears that the effects of inadequate generation in the MISO region would not be limited to areas in which load exceeds generation resources. In addition to public statements made by MISO that firm load shedding would take place across the MISO system if there is not adequate generation resources across the MISO system, the above quote from MISO documents indicates that MISO will take "whatever actions are needed" to protect the bulk transmission system.

Combined, the retirement of existing resources and the structural failure to ensure that enough new resources are constructed could result in an inadequate electric system in MISO.

2. Changing Resource Adequacy Rules

For 2014 MISO requires a Planning Reserve Margin (PRM_{UCAP}) of 7.3 percent. The PRM's for 2010-2014 are shown in Table 1 below.

Table 1: MISO Historical PRMs[2]

Year	PRM (UCAP)	PRM (ICAP)
2010	7.74%	15.40%
2011	8.76%	17.40%
2012	6.66%	14.40%
2013	6.20%	14.20%
2014	7.30%	14.80%

Although the percentage changes from year to year may appear to be fairly small, they are significant when applied to a large system. For example, a 10,000 MW system in 2011 would have required reserves of 876 MW using the UCAP PRM. But in 2013 the reserve requirement would have been 620 MW, a difference of 256 MW, which is a significant change that could affect the amount of capacity the utility needs to add to its system. In the following year, 2014, the reserve requirement would have been 730 MW, an increase in the reserve requirement of 110 MW in just one year.

These wide swings are difficult to plan for, although contingency planning can help incorporate the changes. However, what can't be planned for is MISO's frequent, significant changes in its methods to calculate reserve requirements. When a utility doesn't know the formula there is no way to know how much uncertainty should be considered in planning for the capacity needs of its system.

For many years, the Commission promoted resource adequacy by requiring utilities to meet the peak demand on their own system plus a reserve to help ensure overall system reliability. Long ago, a 15 percent excess reserve requirement was set by the Mid-Continent

[2] UCAP stands for "unforced capacity" whereas ICAP stands for "installed capacity." UCAP is generally a lower percent than ICAP since UCAP takes into account how the facility performs in practice, including the effects of forced (unexpected) outages, whereas ICAP assumes that all of the installed capacity is available.

Area Power Pool (MAPP), an organization that functioned as a reserve sharing planning group and was responsible for resource adequacy.

As explained by Otter Tail in its reply comments, the means by which the Mid-Continent Independent System Operator (MISO), the successor to MAPP has established its resource adequacy has evolved over time. As Otter Tail stated on page 5 of its Reply Comments:

> On July 20, 2011 MISO filed revisions to its tariff's resource adequacy construct provisions with FERC under docket ER11-4081-000. FERC approved the revisions on June 11, 2012 and they became effective for the MISO planning year that began on June 1, 2013. The resource adequacy construct resulting from the July 20, 2011 tariff revisions is known as "Module E1."
>
> Module E1 arrives at each LSE's coincident peak demand requirements in a way that more accurately reflects each LSE's actual diversity in relation to the remaining MISO LSE's.

Otter Tail also states on page 6 of its Reply Comments:

> Because Otter Tail's peak is significantly diverse from MISO's peak, it sees significant diversity benefits in its resource adequacy requirements calculation under Module E1.

Under its construct, MISO sets resource adequacy requirements for its Load Serving Entity members based upon the point in time when the aggregate peak energy usage occurs within the MISO footprint (the MISO coincident peak). In other words, MISO's method requires each LSE to have enough resources to meet MISO's system peak, rather than each LSE's system peak.

Assuming that electricity can be delivered across the MISO region, having each utility plan for the MISO Coincident Peak should result in the same amount of reliability as having each utility plan for their own system peaks. The purpose behind having each LSE plan to have enough resources to meet their share of the MISO CP is to reduce costs. Cost reductions occur when the time that a utility's system peaks differs from the time when MISO's system peaks; such utilities would not need to add as many resources to their system to meet the peak of their system since they would instead be relying on resources in MISO's system to meet a portion of their peak needs. Utilities that are more "diverse" than average from MISO's peak have a lower reserve requirement and those that are less diverse than average have a higher requirement. Before diversity was socialized; now it is utility specific.

Otter Tail rightly pointed out that the Department's recommendation for Otter Tail to plan for its system peak would cost more than planning for MISO's CP. The Department realizes that planning for the MISO coincident peak and PRM requires fewer resources for most Minnesota utilities than planning for the utility's system peak plus a similar Planning Reserve Margin. However, applying MISO's approach used for transmission assets to generation resource planning would result in a major shift in the way that IRPs have been conducted in Minnesota. As a result, the Department has been in dialogue with many parties (including MISO, which we asked to submit comments in this docket) to discuss our concern that Minnesota's planning for the MISO CP may not ensure reliability in the future and the Department has begun to analyze the costs of one of the options for maintaining reliability, requiring that a utility plan for its system coincident peak, as the Department recommended for Otter Tail's resource plan.

Given the concern with the potential costs of a blackout, yet also concerns with costs of procuring additional resources, the Department recommends that the Commission open a generic docket that examines the probability and potential costs of a blackout, and the costs of potential solutions. The Department notes that MISO explicitly allows states to adopt different resource adequacy standards. MISO stated the following in its August 1, 2014 Reply Comments in this Docket:

> MISO recognizes and supports the states in their fulfillment of their state's resource adequacy. For example, the Introduction to Module E-1 (that portion of the Tariff related most specifically to resource adequacy), states:
>
> > These requirements recognize and are complementary to the reliability mechanisms of the states and the Regional Entities (RE) within the Transmission Provider Region. Nothing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction. (MISO Tariff Section 68A)
>
> Again, in a later section, the Tariff makes clear that states may select a specific Planning Reserve Margin (PRM), regardless of the margin used by MISO:
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> > The Transmission Provider will use the Transmission Provider Region PRM for the PRMR calculation unless an alternate PRM is established by a state. In such event, the Transmission Provider will use the alternate PRM that a state regulatory agency has created for the geographic area in which the state has jurisdiction. The Transmission Provider will convert any state provided PRM to a comparable

> > Unforced Capacity basis. (MISO Tariff Section 68A.7)
>
> MISO recognizes that differing PRM's could create additional complexities around resource planning, but stands ready to assist the Commission if it wishes to explore this matter further.

The Department believes that some of the potential solutions include:

a. Requiring utilities serving Minnesota to plan for their own system peak or some amount between MISO's CP and the utility's NCP. This approach was the solution recommended by the Department in our initial comments on Otter Tail's resource plan.
b. Requesting utilities in the short term (next five years) to plan for their own system peak. Otter Tail's preferred plan includes the addition of a 211 MW of combustion turbine in 2021. Otter Tail could implement this solution by moving the addition of this resource to an earlier date.
c. Requesting MISO to change some of its operating rules so that reliability is a more likely outcome. For example, the Department does not consider it reasonable for MISO to charge only the CONE for inadequate resources.

Some of the information that would need to be analyzed in any generic proceeding includes:

23. The potential costs and probability of a blackout,
24. The costs of different solutions,
25. How MISO would treat additional resources added due to Minnesota having a different resource adequacy construct.
26. How additional resources on Minnesota's system would impact reliability of electricity service in Minnesota.

Given that the Department believes that a broad discussion needs to occur about how to ensure the reliability of Minnesota's future electric supply, the Department has modified its recommendation in these comments so that for now, Otter Tail's short-term action plan be based on planning for MISO's CP. The Department is revising its earlier recommendation on this issue at this time because <u>the record regarding the costs and benefits of choosing the more expensive use of NCP has not been adequately developed for the Commission to require the Company to use this standard</u>.

3. Forecasting MISO's Coincident Peak

As noted in Section B.7 of its May 2, 2014 *Comments* in the Otter Tail IRP, the Department identified theoretical concerns regarding a technique suggestion by MISO to estimate the MISO CP. The use of a theoretically questionable process can lead to unreliable forecasts results that could potentially impact system reliability. The Department detailed a theoretically sound method to estimate the MISO CP in its May 2, 2014 *Comments*. This method, which would require the collection of historical data by all MISO members, does not represent the only means to estimate each LSE's contribution to the MISO CP but was illustrative of other approaches. The Department notes that Otter Tail stated in its *Reply Comments* that if support throughout MISO exists, OTP would be amenable to participate in the alternate method described by the Department. However, as MISO recognizes, it is the states and not MISO that sets the generation reserve requirements to be used in state resource planning. Thus, it is not necessary for there to be support throughout MISO prior to the Minnesota Commission setting the reserve requirements for generation resources in an IRP.

On August 1, 2014, MISO filed *Reply Comments* discussing its CP methodology in the Otter Tail IRP. As part of this discussion, MISO stated that it annually reviews the methodology, inputs, relationships, and other technical details associated with the utility forecasts of MISO CP. This review is based on MISO's random sample of utilities in the MISO footprint; MISO stated that it is able to review forecasts associated with roughly 60 percent of its entire load. MISO also stated that there is no set method to forecast each LSE's load contribution to the MISO CP and each utility is free to use the method that best estimates their load at the time of MISO's CP. MISO further stated that individual states are free to set their own planning reserve margin standards and, although this approach may create planning complexities within MISO, it is open to assist the Commission if it wishes to set a planning reserve margin different than estimated by MISO.

In the event that the Commission decides that it prefers Minnesota electric utilities to plan for MISO's Coincident Peak, the Department notes that it plans to evaluate the utilities' responses to Department Information Requests (IR). The IR's were sent to the utilities in reference to obtaining information on the Non-Coincident Peak (NCP) vs the MISO Coincident Peak (CP). Sample IRs are attached to the Department's *Supplemental Comments*.

The following utilities were sent IRs:

- Great River Energy (GRE) in Docket No. ET2/RP-12-1114;
- Interstate Power and Light Company (IPL) in Docket No. E001/RP-14-77;
- Minnkota Power in Docket No. ET6/RP-14-526;
- Minnesota Municipal Power Agency (MMPA) in Docket No. ET6133/RP-13-1165;
- Minnesota Power (MP) in Docket No. E015/RP-13-53;
- Missouri River Energy Services (MRES) in Docket No. ET10/RP-10-735;
- Otter Tail Power Company in Docket No. E017/RP-13-961;
- Southern Minnesota Municipal Power Agency (SMMPA) in Docket No. ET9/RP-13-1104;
- Xcel Energy d/b/a Northern States Power Company (NSP) in Docket No. E002/RP-13-368.

The Department understands that utilities' have been submitting their planning year energy and demand forecasts (June through May) to MISO through MISO's Module E Capacity tracking tool (MECT). Prior to 2012, MISO estimated coincident peak values for utilities based on MISO's estimates of diversity. However, MISO requests that utilities now calculate their own CP.

In order to evaluate the information on the issue of planning for a utility's NCP versus the MISO CP, the Department intends to, for example, evaluate the following:

- The energy and demand data used by the utilities in the IRP forecasts versus the data submitted to MISO;
- Whether the data include transmission and distribution losses; and
- Utilities' calculations and determinations of their contribution to MISO's CP.

The Department intends to evaluate all of the data and submit a summary of our analysis to the Commission in each of the resource planning dockets listed above. The Department appreciates the cooperation of all of the utilities in this endeavor.

B. OTTER TAIL'S USE OF ENERGY MARKETS

In its Strategist modeling, the Department assumed that Otter Tail will have unlimited access to the energy market in the first five years of the planning period, but no access in year six (2019) and beyond. Additionally, in its May 2, 2014 Comments, the Department expressed concern with the degree to which Otter Tail's preferred expansion plan relies on market purchases to meet the Company's energy needs.

In its Reply Comments, Otter Tail objected to the Department's modeling assumption, stating that this approach "would prevent Otter Tail from using the market when it presents an opportunity for reducing energy costs below the fuel costs of its units."[3] The Company also objected to the Department's use of the term "market reliance," and stated that the Company has enough resources through owned facilities, executed bilateral contracts, and load management to serve its load, and is therefore not "relying on the market."[4] Otter Tail stated that it purchases energy from the MISO market only when doing so is less expensive than generating that energy from its native facilities.

The Company explained in its Reply Comments that it models the energy market in Strategist as a mix of bilateral contracts and the day-ahead (MISO) market. The Company stated that it routinely evaluates bilateral opportunities and enters into contracts when it is in the best interest of its ratepayers. Otter Tail summarized its current portfolio of bilateral energy contracts, and stated that over the last several years, it has purchased between 10 and 20 percent of its annual energy needs from the MISO market. This is consistent with the Company's Strategist modeling, as Otter Tail's preferred plan meets approximately 16.5 percent of its energy needs from the MISO market.

Based on our review of Otter Tail's comments the Department continues to conclude that it is unreasonable for Otter Tail to assume that it will have full access to the market over the

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[3] Reply Comments, page 2.
[4] Reply Comments, page 8.

planning period. However, the Department fine-tuned its analysis to base the capacity planning on meeting MISO's CP and made other adjustments. Based on our refined analysis, the Department concludes that Otter Tail's initial short-term supply-side resource plan of 200 MW of peaking in 2021 is reasonable when combined with 300 MW of wind (100 MW additions in each of 2017, 2019, and 2021). The Department explains its analysis below.

1. Otter Tail's Proposed Use of Market Energy

Table 2 below summarizes market purchases from Otter Tail's preferred expansion plan. As shown, Otter Tail currently has bilateral contracts in place through 2018; further over the period 2014-2018, those contracts are expected to cover 4.85 percent of the Company's energy needs. Over the same period, the Company's Strategist modeling indicates that purchases in the day-ahead market are expected to meet approximately 13.60 percent of its energy needs. Over the whole planning period, 2014-2028, the Company's modeling indicates that market purchases will serve 18.14 percent of Otter Tail's energy needs.

Table 2
Summary of Market Purchases in
Otter Tail's Preferred Expansion Plan

Year	Total Energy Needs (MWh)	Contracted Purchases		Day-Ahead Purchases		Total Market Purchases	
		MWh	as % of Total	MWh	as % of Total	MWh	as % of Total
2014	4,801.6	171.2	3.57%	481.9	10.04%	653.1	13.60%
2015	4,972.1	432.7	8.70%	997.6	20.06%	1,430.3	28.77%
2016	5,120.8	204.0	3.98%	773.2	15.10%	977.2	19.08%
2017	5,075.5	203.2	4.00%	600.2	11.82%	803.4	15.83%
2018	5,070.8	204.0	4.02%	551.4	10.87%	755.4	14.90%
2019	5,198.9			932.4	17.94%	932.4	17.94%
2020	5,210.1			716.0	13.74%	716.0	13.74%
2021	5,250.8			1,140.8	21.73%	1,140.8	21.73%
2022	5,313.1			1,301.6	24.50%	1,301.6	24.50%
2023	5,314.3			901.5	16.96%	901.5	16.96%
2024	5,315.4			1,005.6	18.92%	1,005.6	18.92%
2025	5,315.0			969.4	18.24%	969.4	18.24%
2026	5,300.2			859.4	16.21%	859.4	16.21%
2027	5,299.6			843.8	15.92%	843.8	15.92%
2028	5,304.7			838.2	15.80%	838.2	15.80%
2014-2018	25,040.8	1,215.1	4.85%	3,404.3	13.60%	4,619.4	18.45%
2014-2028	77,863.0			12,913.0	16.58%	14,128.1	18.14%

The Department supports the Company's practice of using market purchases when doing so is less expense than running its native generation. In fact, the Department would object if Otter Tail chose not to do so. However, the Department would be concerned if OTP's plan were to assume that market purchases will always be less than the cost of its own generation resources. The Department clarifies that its assumption that Otter Tail will have no access to the MISO market after five years is *for Strategist modeling purposes only*. The Department is not recommending that Otter Tail cease purchasing energy via bilateral contracts and the day-ahead market beginning in 2019.

2. High amount of market purchases exposes ratepayers to cost risk

An expansion plan that relies heavily on market purchases exposes ratepayers to increases in the price of energy from the MISO market, and the assumption of restricted market access beginning in 2019 is intended to protect ratepayers from unexpected increases by planning a least-cost system that relies primarily on itself to provide energy. Otter Tail is correct in asserting that a system with enough capacity to cover its requirements provides some level of ratepayer protection from high market energy prices because the system's native generation provides a price ceiling. If market energy is more expensive than energy generated by native resources, then native resources can be dispatched instead. However, different types of generation units will set different price caps; in Strategist, market price assumptions can impact the types of units chosen in expansion plans. As the assumed market price of energy rises, Strategist becomes more likely to select a unit that sets a lower price cap even though those units have higher initial capital costs than alternatives.

In Otter Tail's preferred plan, for example, its Hoot Lake Plant, a coal-fired baseload unit designed to operate at a high capacity factor, is retired in 2020 and replaced with a 200MW combustion turbine (CT), a natural gas peaking unit designed to operate at a much lower capacity factor. The new CT will set a price cap and will be available to produce energy when market energy prices exceed that cap. However, the CT cannot be expected to provide energy on an annual basis like Hoot Lake. In Otter Tail's Strategist modeling, MISO market purchases make up a significant part of the difference between Hoot Lake's year round operation and a CT's much lower operation as evidenced by the increase in market purchases in 2021 shown in Table 2 above. (Otter Tail's other existing units make up part of the difference as well.) With the new CT, Otter Tail would have enough capacity to meet its own load, but in Otter Tail's preferred plan, customers would face increased risk associated with day-ahead market prices, up to the cap set by the CT.

An alternative expansion plan may have included a natural gas combined-cycle (CC) plant that is designed to operate at a much higher capacity factor than a CT. The CC would set a lower price cap than the CT, but have a higher initial capital cost. If day-ahead market energy prices are, on average, lower than the price cap set by the CC, then the expansion plan with the CT would be least cost, as the higher capital costs would not be offset by savings resulting from foregone market purchases. However, if market prices are, on average, higher than the price cap set by the CC, the expansion plan with the CC would be least cost, as the higher capital costs are offset by savings created by the lower price cap of the CC (relative to the CC). The Department's assumption of no market access after 2018 eliminates the risk posed by the uncertainty surrounding market prices at that time, and the cost difference between the expansion plan assuming market access and the expansion plan assuming no market access can be thought of as the cost of insuring against this market price risk.

3. High use of capacity-only resources also increases risk of day-ahead energy prices

An additional concern the Department's market-access assumption addresses is Otter Tail's use of capacity-only resources. While capacity-only contracts are often reasonable short- and intermediate-term solutions to capacity deficits, they should not be relied upon in the long-term. Otter Tail has several capacity-only contracts in place through 2021, including a total of 50 MW of contracted capacity from July 2019 through May 2021.[5] As shown above, Otter Tail has no bilateral energy contracts in place after 2018, meaning that not all of the resources the Company will use to meet its capacity requirements after 2018 are capable of providing energy. Additionally, in its IRP, Otter Tail modeled its three oil peaking units, totaling 48.4 MW of capacity, as being on permanent outage throughout the entire study period, and stated that it intends to treat these units as capacity-only resources[6]. Thus, nearly 100 MW of Otter Tail's capacity is either not capable of producing energy or not intended to do so (or if they did operate would be at a high cost). A system with too many capacity-only resources may satisfy its reserve requirements without being able to meet its energy needs, exposing ratepayers to the risk associated with day-ahead energy prices. The Department's assumption was intended to protect against this possibility.

4. Refined Department modeling

The Department's initial modeling indicates that a combination of new wind and a 200 MW CT, providing both energy and peaking capacity, is the optimal mix of resources to replace Hoot Lake. The new wind is the major difference between Otter Tail's preferred expansion plan and the Department's preferred plan. One additional difference between the plans is that while both include a 200 MW CT, the Department's modeling indicates a need for this unit in 2019, while Otter Tail's indicates a need in 2021. In Otter Tail's plan, the 200 MW addition is driven by a capacity need, while in the Department's plan, this addition is driven by a need for energy. In other words, in the Department's modeling, there are times in 2019 when Otter Tail's native generation operating at maximum capacity is not capable of meeting Otter Tail's load, particularly during Otter Tail's peak times in the winter months.

In order to test the effects of delaying the 200 MW CT from 2019 to 2021 with no market access, the Department attempted to vary the operational constraints in Strategist in a way that produced an expansion plan that pushed the addition of the 200 MW CT back two years. The Department was able to achieve this result by (1) taking Otter Tail's oil peaking units off of permanent outage and allowing them to produce energy, (2) eliminating planned outages at the Company's Big Stone and Coyote plants, and (3) allowing a large amount of

[5] See Otter Tail's IRP, Appendix C, page 9.
[6] In discussions with the Company, Otter Tail stated that this an assumption for modeling purposes only, and that these units are available to produce energy, and are dispatched when needed.

unserved demand in the model.[7,8] Initially, this unserved demand for energy was set to 30 GWh, and when the market is turned off in 2019, it appears that this is the constraint that pulled the 200 MW CT forward. Strategist could not limit unserved hours to 30 GWh without adding the new CT in 2019. By increasing the number of allowable unserved GWh to 500 (a limit so high that unserved demand is, in effect, unlimited), Strategist produced an expansion plan that delayed the addition of the 200 MW CT until 2021. This plan, however, resulted in a total of approximately 40 GWh of unserved hours in the winter months (January, February, and December) of both 2019 and 2020, which represents approximately 2.5 percent of Otter Tail's energy needs in those months.

While this level is not an extremely large amount of unserved energy, Otter Tail's ratepayers would be exposed to significant price risk if the Company has to purchase this energy from the day-ahead market. The Department notes that energy prices in the MISO market were often quite high this past winter during the polar vortex event. Additionally, there are concerns regarding the winter availability of natural gas-fired generating units in the MISO footprint which have non-firm gas supply in the winter. If the Midwest experiences a cold winter in the next few years, or if a significant amount of new electric generation is expected to rely on natural gas, prices may be quite high again. Additionally, the Department notes that the analysis above uses Otter Tail's median forecast, and if the Company's energy needs are higher, all additional energy will have to come from market purchases as well.

The Department also further evaluated some of the results of our previous Strategist analysis. For example, under the Department's Scenario 2, which included the MISO CP reliability method, the Department's base expansion plan included a 200 MW CT in 2019, and 50 MW CT's in 2021 and 2024. Similar to the 200 MW CT, in the Department's modeling both 50 MW CTs were added as a result of energy needs, rather than capacity needs. When the Department reran this Scenario with Otter Tail's oil peakers turned on (i.e. capable of producing energy), the 2021 CT was eliminated from the expansion plan. Additionally, it appears that Strategist chose the 2024 50 MW CT to cover the needs created by the assumption of a long, six-week, planned maintenance outage for Big Stone, which Strategist selected to occur during a six week period stretching from May into July, meaning that Big Stone would be unavailable during the entire month of June. Because Otter Tail faces relatively high load in June, Strategist required the addition of an extra unit to make up for the energy lost during the outage. By removing this planned outage from the model, the 50 MW CT was eliminated from the expansion plan. The Department concludes that removing this planned outage is reasonable because Otter Tail would not schedule it during peak MISO periods.

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[7] Both Big Stone and Coyote are scheduled for 6- or 7-week outages in 2019, which Strategist was scheduling during June, when Otter Tail faces relatively high demand. Presumably, Otter Tail would not schedule these outages during June, but rather during the spring or fall, when these units are needed less. Strategist users can select for each unit being modeled one month during which the unit CANNOT be scheduled for planned maintenance. Strategist then randomly schedules planned maintenance during the other 11 months. July has been selected as the "off-limits" month for all of Otter Tail's units, meaning that all units are free to be taken offline in any other month, regardless of expected loads.

[8] Unserved demand is demand for energy that goes unsupplied in Strategist.

5. *Summary and Recommendations*

In summary,

- The Department was able to eliminate the need for some additional peaking capacity in later years of the planning period by changing Strategist's method of scheduling outages, a reasonable change.
- Otter Tail's ratepayers would be exposed to market price risk during the winter months, when the Company dependence on the market increases. Otter Tail's use of capacity-only purchases and treatment of oil peaking units as capacity-only resources due to the high cost of operating those units will exacerbate the issue.
- The addition of 300 MW of new wind over the period 2017-2021 was a robust result.

The Department reran the base contingency (described in its Comments) for Scenarios 1, 2, and 3. The Department also ran its base contingency on a new scenario that uses the CP reliability method and assumes full market access throughout the study period. The results are presented in Table 3 below.

Table 3
Top Ranked Expansion Plans
From Department's Scenarios
Using New Maintenance, Unserved Energy, and
Oil Peaker Availability Assumptions

		Department Scenario's			
	Otter Tail's Preferred Plan w/Externalities**	NCP Market Off	CP Market Off	CP with 50% Diversity Factor Market Off	CP Market On***
PVSC* ($ Billions)	4.085	3.940	3.912	3.913	3.892
2017		100 MW Wind 50 MW Peaking	100 MW Wind	100 MW Wind 7 MW Deferral Cap.	100 MW Wind
2018				8 MW Deferral Cap.	
2019		100 MW Wind	100 MW Wind	100 MW Wind	100 MW Wind
2021	200 MW Peaking	100 MW Wind 200 MW Peaking	100 MW Wind 200 MW Peaking	100 MW Wind 200 MW Peaking	100 MW Wind 200 MW Peaking

* Present Value of Societal Costs
** Otter Tail's preferred plan does not reflect externality costs. The Department calculated the PVSC of Otter Tail's preferred expansion plan with the Department's base externality assumptions added in. Thus, the PVSC reported here represents a scenario with the CP reliability method, full market access, and no new wind.

As shown, the major difference between the three Market Off Scenarios is the selection of a 50 MW peaking unit in 2017 in the NCP Market Off Scenario. In the CP with 50 percent Diversity Factor Scenario, small amounts of deferral capacity are used in 2017 and 2018 before the 100 MW wind unit in 2019 is installed. This Scenario represents a conservative application of the CP Reliability Method.

The Department also ran one additional contingency on its CP Market Off scenario in which a 200 MW CT was forced to be selected in 2019 (rather than 2021). The PVSC of that contingency was $3.922 billion, or approximately $10.3 million more than the PVSC of the CP Market Off Scenario when the unit is selected in 2021. This $10.3 million represents the cost of insuring against market risk in the winter months of 2019 and 2020.

Based on our refined analysis, the Department continues to recommend that the Commission approve a resource plan that does not assume that Otter Tail will continue to procure such high amounts of energy from the MISO market. The Department's proposed resource plan includes the cost-effective addition of additional wind in 2017, 2019, and 2021, as well as the 200 MW of peaking facilities that Otter Tail has proposed. As stated above, the Department recommends that the Company procure the 100 MW of wind for 2017, but wait until Otter Tail's next IRP is filed, when EPA's 111(d) rules are better understood, before proceeding with the additional wind.

C. ENERGY CONSERVATION GOALS

The Department continues to recommend that Otter Tail pursue DSM resources equal to 1.7 percent of their retail sales. The Department offers the following clarifications on DSM goal measurement in the IRP and Conservation Improvement Program (CIP) contexts.

In our initial comments the Department, in *Table 4: Otter Tail Power's Historical CIP Achievements and Costs*, included a footnote labeling these savings as measured at the meter. This footnote is incorrect, as Otter Tail points out in its reply comments. The savings listed in Table 4 of the initial comments are measured at the generator. However, correcting the footnote does not change the Department's recommendation. The Department continues to recommend Otter Tail pursue 1.7 percent annual energy savings as measured at the generator.

This docket has highlighted the difference in how energy savings goals are communicated differently in the CIP and IRP processes. CIP energy-savings goals are calculated using the three year weather normalized average sales of a utility in the previous three years prior to the utility submitting its CIP triennial plan. This approach is specified in Minnesota Statutes 216B.241, subd. 1c(b). In contrast, when the Department reviews DSM goals in the IRP, the Department reviews proposed energy savings levels with the forecasted energy requirements and retail sales in the year the energy savings are procured.

To illustrate this difference, the Department compared Otter Tail's 2014-2016 Triennial CIP goals with how the same energy savings may be calculated in the IRP. The Department's proposed energy savings are also compared by the same metrics in Table 4 below.

Table 4: Energy Saving as Measured by CIP and IRP Percentage Goals

Otter Tail CIP Goals					Department IRP			
Year	CIP Savings Goal (GWh at the generator)	CIP Percentage	CIP savings as a Percent of MN Energy Requirements	CIP savings as a Percent of MN Sales after conservation	Proposed IRP Savings Goal (GWh at the generator)	CIP Percentage (estimate)	Savings as a Percent of MN Energy Requirements	Savings as a Percent of MN Sales after conservation
2014	31.49	1.51%	1.36%	1.42%	35.41	1.69%	1.52%	1.60%
2015	31.48	1.51%	1.31%	1.34%	35.77	1.71%	1.49%	1.52%
2016	32.20	1.54%	1.24%	1.29%	36.62	1.75%	1.41%	1.47%

As seen in Table 1, Otter Tail's proposed energy savings levels are different percentages when measured using CIP weather-normalized averages then when measured as percent of retail sales in the year the savings measures are installed.

The Department does not agree that an IRP's energy savings goal should be dependent on whether an equal (or greater) CIP energy-savings goal exists. The CIP energy savings goal is not a ceiling on energy conservation. While the standard CIP goal for utilities pursuant to statute[9] is 1.5 percent of gross annual retail energy sales, unless modified by the Deputy Commissioner, the Department is supportive of utilities achieving higher levels of cost-effective savings within the CIP program should a higher DSM level be approved in an IRP and notes that there are budget flexibility and program modification processes to allow a utility to exceed its approved CIP budgets.

An IRP attempts to optimize the specific mix of supply-side and demand-side resources to create a least cost resource plan while maintaining reliability. In the IRP the Department compares DSM lifetime costs to supply side resource costs to determine the optimum cost effective level of DSM resources. The IRP is the primary docket in which the Department compares demand and supply side resources. This approach is supported by Minnesota Statute 216B.2401:

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.

Finally, as noted above, in the time since Otter Tail filed the Company's IRP in December 2013 and the Department filed its initial Comments, the U.S. EPA released the proposed Clean Power Plan rule for existing sources. While significant details of the rule are still under development, energy efficiency is one of the four building blocks used to establish state

[9] Minnesota Statutes 216B.241 subd. 1c (b)

goals and will likely be part of any state implementation plan. The value of additional DSM in complying with the Clean Power Plan was not part of the Department's analysis; therefore, there will likely be additional benefits to the Department's proposed 1.7 percent of cost effective DSM beyond what was considered in this analysis.

In summary, the Department continues to recommend a 1.7 percent DSM goal for resource planning; this goal, as measured using the CIP goal methodology, is 35.77 GWh in first year savings in 2015. In future resource plans, the Department will explore recommending energy-savings levels that do not rely on percentages to avoid confusion between the CIP plans and DSM in the IRP. The Department will continue to evaluate DSM goals by the energy and capacity saved in the same way the Department evaluates supply side resources.

D. RENEWABLE ENERGY STANDARD (RES)

In its reply comments, OTP noted discrepancies between its estimates of RES compliance and the Department's assessment. OTP stated that the discrepancies were due to the Department not reflecting a full year's generation from Ashtabula III in ongoing annual generation, and the effect of a one-time REC sale. Ashtabula III began commercial operation in October 2013; consequently, 2013 generation amounts did not contain a full year's operation and understated the ongoing annual renewable generation used for determining RES compliance. In addition, OTP indicated that it had sold approximately 300,000 2013 vintage RECs which resulted in further under estimating the annual RECs available for future compliance.

In discussions with the Department, OTP stated that it distributes RECs among the three states in which it operates based on a load share for each of those states. This allocation methodology results in roughly 50 percent of the RECs awarded to Minnesota, 40 percent to North Dakota and 10 percent to South Dakota. The RPS requirements in North and South Dakota do not take effect until 2015. Until that time, the Company will sell a portion of its RECs for North and South Dakota, and return the proceeds to its ratepayers in those states. OTP states that the remaining active REC balance (not 50 percent of the active REC balance assumed by the Department) is available for use towards Minnesota compliance.

The Department recalculated OTP's ability to comply with its RES obligations. Table 5 below reflects the inclusion of Minnesota's share of a full year's estimated generation for Ashtabula III, as well as Minnesota's share of the one-time REC sale that will remain part of future generation to the "Annual Renewable Generation" column. The cumulative balance reflects an assumption that all active RECs through 2013 are available for Minnesota RES compliance.

Table 5: Minnesota RES Compliance with Existing Resources

Year	MN REO/RES Requirement MWh	Annual Renew. Generation (MWh)	Existing Gen. less RES Req. Surplus/(Deficit) MWh	Cumulative
				Beg. Balance (through 2013): 1,087,007
2013	259,734	206,079	(53,655)	1,087,007
2014	265,200	412,708	147,508	1,085,219
2015	282,360	412,708	130,348	1,066,271
2016	423,810	412,708	(11,102)	905,873
2017	414,630	412,708	(1,922)	754,655
2018	411,400	412,708	1,308	606,667
2019	429,250	412,708	(16,542)	440,829
2020	504,400	412,708	(91,692)	199,841
2021	509,200	412,708	(96,492)	45,946
2022	518,000	412,708	(105,292)	300,534
2023	515,600	412,708	(102,892)	552,722
2024	513,200	412,708	(100,492)	802,510
2025	638,750	412,708	(226,042)	1,177,848
2026	636,000	412,708	(223,292)	1,550,436
2027	633,750	412,708	(221,042)	1,920,774
2028	631,500	412,708	(218,792)	2,288,862

Table 6 below recalculates OTP's compliance with its RES obligations throughout its three state serving area.

**Table 6: 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 (through 2013): 1,087,007
2013	259,734	416,335	156,601	1,087,007
2014	265,200	905,337	640,137	1,727,144
2015	509,460	905,337	395,877	2,123,020
2016	650,810	905,337	254,527	2,377,547
2017	642,730	905,337	262,607	2,640,153
2018	640,900	905,337	264,437	2,904,590
2019	660,250	905,337	245,087	3,149,677
2020	736,800	905,337	168,537	3,318,213
2021	743,000	905,337	162,337	3,480,550
2022	753,100	905,337	152,237	3,632,786
2023	752,000	905,337	153,337	3,786,123
2024	750,900	905,337	154,437	3,940,560
2025	877,550	905,337	27,787	3,968,346
2026	874,500	905,337	30,837	3,999,183
2027	873,150	905,337	32,187	4,031,369
2028	872,200	905,337	33,137	4,064,506

The Department concludes that assuming the four-year shelf life for RECs, OTP has the ability to meet its Minnesota RES and other state renewable obligations over its planning horizon.

E. AMOUNT OF WIND

In its Reply Comments, Otter Tail stated its desire to delay adding any more wind until the EPA's 111(d) are more clear. Specifically, Otter Tail stated the following on pages 10-11:

> Depending on the outcome of these Rules and other related proceedings, such as state implementation plans and any multi-state compliance proceedings, there may be significant benefits if certain generation projects are located within certain states. There may be regret if a project were constructed earlier than necessary and it is determined later that the construction occurred in a state where the project's full contribution to the EPA goals are not realized.

In response to this uncertainty, Otter Tail requests flexibility in the installation of additional wind resources. Otter Tail said the following on page 11 of its reply comments:

> Otter Tail would not be opposed to an order allowing the addition of up to 200 MW of wind to its five year action plan assuming prices at the time of acquisition are cost-effective. However, it would be opposed to a requirement to initiate an RFP proceeding or build a specific amount of new wind until the outcome of the EPA 111(d) rules are more clear. For these reasons, Otter Tail recommends that any authority granted to add such resources include adequate flexibility to allow greater clarity of the EPA's 111(d) rules to develop.

The Department concludes that the following factors should be taken into account when making decisions regarding Otter Tail's procurement of wind power:

- The Department's analysis shows that 100 MW wind units are cost-effective for Otter Tail's system in each of 2017, 2019, and 2021, regardless of whether the Company is planning for its NCP or MISO's CP.
- Given the timing of the need for the additional wind, the Commission only needs to make a decision on the 2017 100 MW wind recommendation. A decision on the additional 200 MW of wind can be deferred until Otter Tail's next IRP.
- Otter Tail has a significant need for energy in the near future. Cost-effective wind will reduce Otter Tail's dependency on market purchases when market costs may be higher due to compliance with EPA's MATS rule.
- Currently there is a proposal to credit renewable generation sources to the states that compelled the energy, but EPA's final rules may not include that provision.

The Department believes that the Commission must balance the uncertainty of whether Otter Tail's procurement of new wind resources (likely in North Dakota) will help Otter Tail meet State Implementation Plans enacted to meet EPA 111(d) rules with the Company's need for cost-effective energy. The Department concludes that the appropriate balance is to require Otter Tail to procure 100 MW of wind in 2017 and to delay decisions on other wind power until the Company's next IRP. Consequently, the Department recommends that the Commission approve the addition of 100 MW of wind for Otter Tail in 2017, but delay further additions of wind to the Company's system until the impacts of Otter Tail's wind procurement on EPA 111(d) compliance are further clarified.

F. FORECASTING ISSUES

In its *Comments*, the Department requested that Otter Tail provide additional discussion and information on various forecasting related topics. The Department responds separately to each topic below.

1. Heating Degree Base

While reviewing the Company's energy requirements and demand forecasts, the Department observed that Otter Tail used a 55 Heating Degree Day (HDD) base for its average temperature determinants in its forecasting analyses. The Department requested a full explanation of the use of a 55 HDD base because it marks a departure from the 65 HDD base that the Company has used in previous regulatory filings.[10]

In its *Reply Comments*, Otter Tail provided graphs, by rate class, plotting daily temperature in Fahrenheit and daily consumption in kWh over the period from 2008 to 2010. The Department reviewed the graphs and over this period. Based on the graphs, it appears that base consumption on OTP's system happens around 55°F to 60°F dependent upon the rate class. Based on graphical data provided by the Company, it appears that the use of the 55 HDD base is acceptable for planning purposes in this docket. However, the Department recommends that Otter Tail provide detailed data, calculations, and written explanations in its initial filings in future regulatory filing which require a forecasting analysis (*e.g.*, general rate cases, integrated resource plans) supporting its HDD base.

2. Weather Interaction Term

In its *Comments*, the Department expressed concern with Otter Tail's use of a weather interaction term in its forecasting analysis because this approach created two variables with the same data stream over parts of the historical period and throughout the entire forecasting period. Based on these concerns, the Department requested that the Company fully explain in *Reply Comments* the steps it took to verify that the weather interaction term did not impair the estimative power of the forecasts and an explanation, and data if available, which supports a change in weather's impact on consumption.

Otter Tail responded that the interaction terms were included in the forecasting models as the result of changes in the Company's capacity control set point[11]. Starting in the winter of 2007, Otter Tail noticed that the change in the capacity control set point resulted in an increase in winter demand and, during the early part of 2012, the Company noticed that

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[10] As noted in the Department's *Comments*, there is no standard HDD base, but the specific base used by a utility can impact regression results. Theoretically speaking, the most appropriate HDD base number will be the base that best represents the temperature at which consumption begins being influenced by heating load. In general, however, utilities in Minnesota have used the 65 HDD base in their forecasting analyses.

[11] The capacity control set point is the load level at which OTP initiated capacity control. For example, if Otter Tail didn't want its load to exceed 800 MW, the Company would set the capacity control set point to 780 MW. Once load built up to 780 MW the Company would initiate its demand response programs. After the MISO rules changed related to load forecasting on June 1, 2013 Otter Tail no longer establishes a capacity control set point.

forecasting error during the winter months was increasing for its energy requirements forecasts. Otter Tail also responded to the Department's concerns regarding the interaction term and possible impacts to the estimative power of the models by stating that the Company reviewed the model outputs and noted that each variable, weather and the interaction term, had significant T-Statistics (greater than 1.96 in absolute value). In the Company's opinion, this result suggests a lack of correlation between the variables because a symptom of collinearity between variables is a decrease in the significance level for a variable, or variables.

The Department appreciates Otter Tail's response on this issue. The Department reviewed the Company's various regression models and agrees that both variables exhibit significant T-Statistics; however, the Department's primary concern with Otter Tail's model specifications are not outcome based. From a strictly outcome standpoint, the Department concludes that the Company's energy requirements and demand forecasts appear to be reasonable for planning purposes. However, Otter Tail's model specifications from a process, or theoretical, standpoint do not represent the most appropriate method to account for a change in system characteristics.

As noted above, and in the Company's *Reply Comments*, the Company included the weather interaction terms in response to a change in the Company's capacity control set point, which resulted in increases in peak demand and energy consumption that were not adequately estimated by existing regression models. The Department agrees with Otter Tail's decision to account for the change in the capacity control set point; however, the Department remains concerned about the specification of the weather interaction term. Although collinearity between weather and the interaction term appear to be insignificant at this time, there is no way to guarantee that collinearity will not become a problem in the future. Using the current model specification, as time goes by, the amount of identical historical data for the two variables will increase and, all else being equal, the risk of correlation between the two variables will increase. If the capacity control set point is the primary cause of the change in energy consumption and peak demand, as surmised by the Company and backed, at least anecdotally, by forecast error results, the Department believes that specifically modeling this event is more appropriate. Modeling the event should remove the possibility of collinearity going forward and remove the theoretical concerns referenced by the Department in its Comments. As such, the Department recommends that the Company investigate other regression specifications and methods to account for the change in the capacity control set point in future regulatory filings.

3. Deployment of Demand Response

In its Comments, the Department expressed concern regarding the availability of demand response (DR) on an Otter Tail system peak because the Company's demand response and load management controls are dispatched by MISO and not Otter Tail. The Department requested that Otter Tail provide additional discussion and supporting daily data in its Reply Comments regarding demand response and its availability to the Company.

Otter Tail explained in its Reply Comments that it currently has two demand response resources registered as Load Modifying Resources (LMR) with MISO. At the time of the IRP filing, Otter Tail stated that its firm service level customer was registered at 15 MW and its direct load control programs were registered at 15 MW. Otter Tail explained that registering these resource with MISO means that they must be available for use by MISO during all types of emergencies, both capacity and transmission, and if these resources are not available Otter Tail is subject to penalties unless the Company can show that the resource was otherwise deployed for economic or load reliability reasons.

The Company clarified that other than limitations set in retail tariffs, Otter Tail is not limited in its ability to deploy its demand response. The Company stated that other than when directed by MISO, Otter Tail typically only deploys its DR for economic purposes. Further, Otter Tail stated that it can deploy its DR for local transmission reliability purposes, without limitation, but it has not done so during the time that DR has been registered with MISO.

Otter Tail provided historical, daily demand response data in its Reply Comments. As part of these data, the Company also provided a clarification as to why load was curtailed for each event (*e.g.,* economic, capacity constraint). As noted above, the Company currently has 30 MW of DR registered with MISO; however, based on a review of the historical daily data, the Department notes that there have been 397 days since January 2005 where Otter Tail curtailed greater than 30 MW.[12] The Department further notes that 120 of these days with curtailments in excess of 30 MW have occurred since the effective date of MISO Module E1 (June 1, 2012); however, the Company noted in a discussion with the Department that MISO has not declared an emergency where Otter Tail's DR has been deployed since June 1, 2012.

The fact that the Company has curtailed amounts greater than the registered amount of DR with MISO, and the fact that Otter Tail is able to deploy its DR for local transmission reliability purposes, suggests that Otter Tail has sufficient DR available at this time to manage its system when required. However, based on the discussion provided in Reply Comments, it is still unclear whether MISO only has control over the 30 MW of registered DR, or if MISO has full control of the dispatch of Otter Tail's DR and the 30 MW simply represents the credited amount that the Company receives. In addition, since MISO has not had an emergency event where DR has been deployed, up until this point, it is also unclear who has been in charge of load management. Given these concerns, the Department recommends that Otter Tail clarify in this record whether it has control over any demand response beyond the amount registered with MISO or whether it has ceded complete control of the dispatch of DR to MISO.

4. Conclusions and Recommendations

Based on its review, the Department concludes that Otter Tail's system peak demand and energy requirements forecast are acceptable for planning purposes.

[12] Otter Tail Reply Comments, Attachment 2.

The Department also recommends that the Commission require Otter Tail to:

- clarify in this record whether the Company has control over any demand response beyond the amount registered with MISO or whether Otter Tail has ceded complete control of the dispatch of DR to MISO;
- provide detailed data, calculations, and written explanations in its initial filings in future regulatory filing which require a forecasting analysis (*e.g.,* general rate cases, integrated resource plans) supporting its HDD base; and
- investigate other regression specifications and methods to account for the change in the capacity control set point in future regulatory filings.

Otter Tail's analysis of solar resources makes meeting the Solar Energy Standard more costly that it would be.

G. MEETING THE STATE'S GREENHOUSE GAS EMISSIONS REDUCTIONS GOAL

In its initial and reply comments the Environmental Intervenors stated that Otter Tail's proposed resource plan does not meet the State greenhouse gas reduction goal. In the Department's initial comments we presented analysis of the cost for Otter Tail to meet the state's greenhouse gas goal as well as an estimate of how it is faring compared to the reduction goal. As shown in Table 16 on page 16 of our initial comments, the Department projects that the Company's CO_2 emissions would have declined by six percent in 2025, far from the state's goal. In the past the Commission has not required a utility to meet the greenhouse gas reduction goal. If the Commission wishes to approve a resource plan only in the event that it meets the reduction goal, the Commission should make its preference known.

H. COSTS OF MEETING THE SOLAR ENERGY STANDARD

The Environmental Intervenors state that Otter Tail's preferred plan would not comply with the State's Solar Energy Standard (SES). Further, the Environmental Intervenors state that Otter Tail's combination of high solar cost, real price increases, and undervaluing of solar capacity have biased the Company's modeling against solar resources and make complying with the SES appear to be more costly that it is likely to be.

The Department notes that we proposed a resource plan that complied with the State's SES. The Department's analysis estimated that compliance costs could range between 1.0 and 3.6 percent of total plan costs, and that solar would have to cost less than $75 per MWh to be cost-effective. The Department's future estimates will depend on availability of the production tax credit, base costs, assumed inflation, and assumed capacity costs. The Department will update its estimate of the Company's SES in Otter Tail's next IRP, which the Commission will consider in plenty of time for a decision to be made before the SES must be filled by the end of 2020, according to Minnesota Statutes 216B.1691, Subdivision 2f.

I. OTTER TAIL'S MODELING OF WIND

On page 9 of its Reply Comments the Environmental Intervenors argue that Otter Tail may be overestimating the price of new wind resources. The Department's analysis has already shown that an additional 300 MW of wind is cost-effective by 2021. However, the Department brings the Commission's attention to a recent report from the U.S. Department of Energy, 2013 Wind Energy Technologies Report (August 2014), which shows that the price of wind is at an all time low in the U.S.:
http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf

J. DEPARTMENT'S RECOMMENDED RESOURCE PLAN

Based on our review of the comments of Otter Tail Power Company, MISO, and Environmental Intervenors, the Department recommends that the Commission approve a resource plan based on the following conditions:

27. Planning for MISO's Coincident Peak;
28. Include 100 MW of wind in 2017 but wait on decision regarding additional 200 MW of wind until the Company's next IRP,
29. Inclusion of DSM equal to 1.7 percent of retail sales.
30. Assuming only minimal purchases from market energy after five years.
31. Including 20 MW of solar power.

The largest difference between the three scenarios is the timing of peaking capacity.

III. DEPARTMENT RECOMMENDATIONS

The Department provides its updated recommendations below.

A. FORECAST

Based on its review, the Department concludes that Otter Tail's system peak demand and energy requirements forecast are acceptable for planning purposes.

The Department also recommends that the Commission require Otter Tail to:

- clarify in this record whether the Company has control over any demand response beyond the amount registered with MISO or whether Otter Tail has ceded complete control of the dispatch of DR to MISO;
- provide detailed data, calculations, and written explanations in its initial filings in future regulatory filing which require a forecasting analysis (*e.g.,* general rate cases, integrated resource plans) supporting its HDD base; and
- investigate other regression specifications and methods to account for the change in the capacity control set point in future regulatory filings.

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 in 2017; 100 MW of wind and 21 MW of solar in 2019, and 100 MW of wind and 200 MW of peaking generation in 2021.

D. ENVIRONMENTAL ISSUES

The Department recommends that the Commission find that OTP is adequately tracking environmental regulations that might impact its operations.

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.

/lt

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Supplemental Comments

Docket No. **E017/RP-13-961**

Dated this 29th day of August 2014

/s/Sharon Ferguson

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