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Direct Testimony  
Farah L. Mandich

**STATE OF NORTH DAKOTA**  
**BEFORE THE**  
**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

In the Matter of the Application of Northern States Power Company  
for an Advance Determination of Prudence for the Acquisition of the  
120 MW Northern Wind Facility

Case No. PU-21-\_\_\_\_  
Exhibit\_\_\_\_(FLM-1)

**Resource Planning**

March 2, 2021

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**I. INTRODUCTION AND QUALIFICATIONS**

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Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Farah L. Mandich. I am a Specialist, Resource Planning for Northern States Power Company-Minnesota (NSP or Xcel Energy or the Company). The Company provides electric service to customers in Minnesota, North Dakota, and South Dakota (collectively the NSPM States). The Company's affiliate, Northern States Power, a Wisconsin corporation (NSPW), provides electric service to customers in Wisconsin and Michigan. The Company and NSPW, together under the Interchange Agreement, own and operate the five-state integrated NSP System.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since April 2019 in the areas of Regulatory Affairs and Resource Planning. I have been in my current position since October 2020. In my first role with the Company, in the Regulatory Affairs department, I worked with cross-functional teams to develop Integrated Resource Plan and resource acquisition filings for NSP.

Prior to joining Xcel Energy, I worked as a Policy Advisor for Southern California Edison, a large investor owned utility in California. In this role, I supported development of Integrated Resource Planning and resource acquisition regulatory filings before the California Public Utilities Commission. My statement of qualifications is provided as Exhibit\_\_\_\_(FLM-1), Schedule 1.

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1 Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

2 A. In my current role, I work within the Resource Planning team on the  
3 development of resource plans and acquisitions for the five-state integrated  
4 Upper Midwest Northern States Power Company system (NSP System),  
5 which provides electric service to customers in North Dakota, South Dakota,  
6 Minnesota, Wisconsin, and Michigan. This includes assisting the Company in  
7 making reasonable and prudent acquisition decisions for electric generation  
8 resources.

9

10 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

11 A. The purpose of my testimony is to discuss the economic impacts of the  
12 Company's proposed acquisition of the repowered and expanded 120  
13 megawatt (MW) Northern Winds project. My testimony supports the  
14 conclusion that the North Dakota Public Service Commission (Commission)  
15 should grant an advance determination of prudence (ADP) for the proposed  
16 resource acquisition. My testimony provides an economic analysis of the  
17 proposed acquisition and the overall ratepayer benefits it generates.

18

19

**II. ECONOMIC ANALYSIS**

20

21 Q. HOW DID THE COMPANY EVALUATE THE ECONOMIC IMPACT OF THE  
22 PROPOSED NORTHERN WIND ACQUISITION?

23 A. The Company performed two economic analyses to evaluate the present value  
24 of revenue requirements (PVRR) impacts of the acquisition of the repowered  
25 and expanded Northern Wind project: (1) a "pro forma" spreadsheet analysis,  
26 and (2) a traditional analysis using EnCompass.

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**A. Pro Forma Analysis**

Q. WHAT IS A PRO FORMA ANALYSIS?

A. A pro forma is a spreadsheet analysis which uses project cost and production information, along with the Company's financial assumptions, to evaluate the present value and annual cost implications of a proposed acquisition. Specifically, the pro forma compares the expected costs of the Project to a baseline where the existing PPAs remain in our portfolio until the end of their terms and generic wind generation equivalent to the expected output of the Northern Wind Project is added thereafter. Further, in recognition of Advocacy Staff's request in the Mower County Wind ADP proceeding (Case No. PU-19-310), we also performed a pro forma analysis in which we compared the Project to a baseline where the cost of replacement energy is represented by market prices.

Q. WHAT WERE THE RESULTS OF THE PRO FORMA ANALYSIS?

A. Our pro forma analysis showed that the Project would be expected to result in \$30.2 million of customer savings over its lifetime, as compared to generic wind replacement. These savings are on a PVRR basis and do not include carbon dioxide costs, other environmental externality values, or costs for potential future carbon emissions regulations.

Q. WHAT WERE THE RESULTS OF THE PRO FORMA ANALYSIS USING MARKET ENERGY AS A REPLACEMENT FOR THE EXISTING PPAs?

A. Our pro forma analysis of the Project as compared to market price energy replacement after the current PPAs expire showed that the Project would

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1 result in an estimated \$1.4 million of customer savings over its lifetime. Market  
2 price assumptions in this analysis were aligned with those used in our current  
3 resource planning process filed with the Commission in Case No. PU-19-220.  
4

5 Q. WHAT DO THE RESULTS OF THE PRO FORMA ANALYSIS INDICATE?

6 A. The results of our pro forma analysis indicate that the Project is expected to  
7 provide cost savings to the Company's customers on a standalone basis,  
8 regardless of whether the existing PPAs are assumed to be replaced with  
9 generic wind resources or market energy. With this in mind, the Company  
10 conducted full resource planning modeling of the proposed Project using the  
11 EnCompass tool.  
12

13 **B. Encompass Analysis**

14 Q. WHAT IS ENCOMPASS?

15 A. EnCompass is a capacity expansion and production cost modeling tool that  
16 allows the Company to optimize resource expansion plans based on a set of  
17 assumptions. Like Strategist, our previously-used resource planning model,  
18 EnCompass simulates the operation of the NSP System and estimates the total  
19 cost of energy over the life of the project on a present value basis. However,  
20 one of the primary differences between EnCompass and Strategist is that  
21 Encompass evaluates resource needs and cost on a chronological hourly basis,  
22 which better accounts for hourly variations on our system. The Company has  
23 largely shifted to using the EnCompass tool rather than Strategist to perform  
24 resource planning modeling because, as we add more variable resources to our  
25 system, it becomes increasingly important to ensure we are appropriately  
26 considering resource needs on an hourly basis.

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Q. HOW DID THE COMPANY USE ENCOMPASS TO ANALYZE THE PROPOSED NORTHERN WIND ACQUISITION?

A. For this analysis, the Company simulated the operation of the NSP System through 2045, with and without the acquisition of the 120 MW Northern Wind facility, under a range of different assumptions. The Company's analysis assumes the addition of the four wind repowering projects described in the Company's pending ADP application in Case No. PU-20-425, as well as one under 50 MW repowering project for which the Company did not seek an ADP. The Company had initially selected a total of seven repowering projects, but negotiations have ceased for two of the small PPA projects for which the Company did not seek an ADP.

Q. WHY DID THE COMPANY'S MODELING USE THE ASSUMPTION THAT THE OTHER WIND REPOWERING PROJECTS WOULD BE ADDED TO THE SYSTEM?

A. As I noted in my Direct Testimony in Case No. PU-20-425, the Company conducted a portfolio analysis of the repowering proposals that were initially shortlisted to validate that the full portfolio of repowering projects would yield customer benefits. Because the Company considers the Northern Wind project as part of its overall current repowering portfolio proposal and in order to determine if the Northern Wind project would have incremental benefits in addition to the other repowering projects, we analyzed the customer impacts of the Northern Wind project in the context of the other repowering projects that have already been proposed.

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1 Q. WHAT MODELLING INPUTS AND ASSUMPTIONS WERE USED IN THE  
2 ENCOMPASS MODELLING?

3 A. We evaluated the Northern Wind project's economic impact to our system  
4 using the same modeling assumptions as we used in Case No. PU-20-425, but  
5 as noted above we updated the Base Case to include the four wind repowering  
6 projects described in the Company's application in that case and one  
7 additional under 50 MW repowering project which was not included in that  
8 application. The full list of EnCompass modeling assumptions used in the  
9 Company's analysis is provided as Schedule 2 to my Direct Testimony.

10

11 This Base Case is compared with a Change Case in which the existing  
12 Chanarambie and Viking PPAs are removed from our portfolio and replaced  
13 with the repowered and expanded Northern Wind project. This allows us to  
14 examine whether the proposal will result in customer savings in the context  
15 of our full NSP System.

16

17 Q. WHAT WERE THE RESULTS OF THE ENCOMPASS ANALYSIS?

18 A. The results of our EnCompass analysis show that under our base assumptions,  
19 the acquisition of the repowered and expanded Northern Wind project results  
20 in net benefits of \$54 million on a PVRr basis over the 2020-2045 analysis  
21 period. These cost savings do not include carbon dioxide costs, other  
22 externality values, or potential future regulatory costs for carbon emissions.

23

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1 Q. DID THE COMPANY TEST THE IMPACT OF THE PROJECT UNDER OTHER  
2 SENSITIVITIES?

3 A. Yes. We also tested the impact of the Northern Wind project under sensitivity  
4 analyses for high and low gas, coal, and market prices. The full results of our  
5 Encompass analyses are included in Table 1 below. Our analysis indicates that  
6 the Project is expected to result in benefits to customers under all fuel  
7 sensitivities examined.

8 **Table 1: Savings Associated with the Addition of the**  
9 **Northern Wind Project, Relative to the Base Case**

Cost sensitivity	Cost/(Savings) \$2020 millions
Base PVRR	(\$54)
Low Gas, Coal and Market Prices PVRR	(\$62)
High Gas, Coal, and Market Prices PVRR	(\$39)

10

11 Q. IN GENERAL, WHAT IS THE SOURCE OF THE SAVINGS ASSOCIATED WITH THE  
12 NORTHERN WIND ACQUISITION?

13 A. Our modeling efforts show that we expect there to be fuel savings – offsetting  
14 generation from higher cost resources on our system – as a result of acquiring  
15 this Project. The analysis also shows benefits associated with the potential for  
16 this Project to defer future capacity additions, as discussed later in my  
17 testimony. Finally, the benefits reflect the value of Production Tax Credits  
18 (PTCs) and associated impacts to the Company’s tax position, to the benefit  
19 of customers.

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1 Q. WHY ARE THE SAVINGS PROJECTED BY THE ENCOMPASS MODELLING EFFORTS  
2 DIFFERENT THAN THE ESTIMATED SAVINGS UNDER THE PRO FORMA  
3 ANALYSIS?

4 A. The pro forma model and EnCompass modeling represent two different  
5 approaches to examining potential customer benefits or costs attributable to  
6 the proposed project. The pro forma model shows us the expected revenue  
7 requirements of the Project as compared to one single alternative for an  
8 equivalent amount of replacement energy; here, either new generic wind or  
9 market energy. In EnCompass, we analyze the project within the context of  
10 our full Upper Midwest system, where the Encompass model analyzes system  
11 resource options and selects an optimal future capacity expansion plan and  
12 estimated dispatch patterns in a case with the Project included – what we call  
13 the “Change Case” – as compared to a “Base Case” without the Project  
14 included. In that way, the EnCompass analysis allows us to more dynamically  
15 examine a broader range of potential impacts based on our input assumptions.  
16 For example, the difference between the Base Case and Change Case in  
17 EnCompass helps us examine whether the addition of this Project could  
18 displace existing fuel sources or market interactions, or result in deferral of  
19 other capacity additions. In either case, however, the difference between the  
20 Base Case and the Change Case is a helpful way to examine whether we would  
21 expect customer benefits to result from the acquisition of the Project. Because  
22 both our pro forma analyses and our EnCompass analyses indicate that there  
23 will be cost savings from the Project, our confidence level that some amount  
24 of savings will accrue to customers in the long term is high.

25

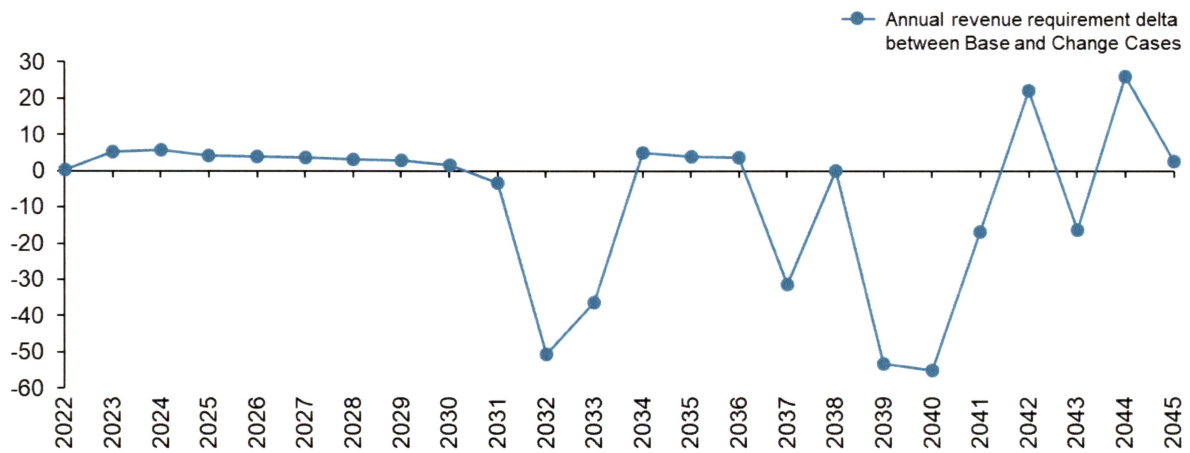
**C. Annual Impacts**

Q. DID THE COMPANY ANALYZE HOW THE COST SAVINGS FROM THE NORTHERN WIND ACQUISITION EVOLVE OVER THE LIFE OF THE PROJECT?

A. Yes. To understand how the potential costs or savings associated with the Northern Wind acquisition accrue over time, we examined total system costs on an annual basis. Figure 1 below portrays the annual (undiscounted) system cost impacts of the Base Case compared to a scenario in which the repowered and expanded Northern Wind project is added to our system.

**Figure 1: Annual Costs/(Savings) of Northern Wind vs. the Base Case**

**Annual cost/(savings) of the Northern Wind Project, relative to the Base Case**  
\$ millions



Q. WHAT ACCOUNTS FOR THE FLUCTUATION IN CUSTOMER COSTS AND SAVINGS OF THE NORTHERN WIND REPOWERING RELATIVE TO THE BASE CASE OVER THE ANALYSIS PERIOD?

A. The fluctuation in the annual revenue requirement delta shown in Figure 1 is caused in part by Project-specific impacts such as the impact of deferred tax assets in the early 2030s. It is also the result of the Change Case shifting –

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1        either forward or back – the year in which the capacity expansion model  
2        selects additional future generic resources to serve our customer load. The  
3        shifting in resource additions in particular leads to some of the year over year  
4        cost fluctuations in light of the types of generating units that our assumptions  
5        provide as options for the modelling algorithm to select to optimize the  
6        system. We currently use large generic units in our modeling to maintain  
7        continuity with legacy modeling utilizing the Strategist resource planning tool.

8  
9    Q.    WHAT IS THE CAUSE OF THE DECREASE IN SYSTEM COSTS RELATIVE TO THE  
10    BASE CASE IN 2032?

11   A.    The annualized savings for 2032 relative to the Base Case are the result of two  
12    key factors. First, the estimated revenue requirement for the Northern Wind  
13    Project drops substantially in the 2031-2032 timeframe due to the impacts of  
14    the PTCs generated by the Project on the Company's tax position. Second,  
15    the overall expansion plan in the Change Case indicates that the Project delays  
16    generic resource additions in 2032 by one wind unit (equating to 750 MW of  
17    wind) for two years. The drop in cost reflects both the avoided capital cost of  
18    that wind unit in 2032 and other associated costs (such as assumed integration  
19    costs), outweighing any other factors that put upward pressure on costs in that  
20    year.

21  
22   Q.    WHAT ACCOUNTS FOR THE FLUCTUATIONS SHOWN IN FIGURE 1 IN 2037 AND  
23    AFTER?

24   A.    The relative cost of the Change Case to the Base Case begins to fluctuate again  
25    in 2037 and beyond due in part to deferred or pulled-forward generic additions  
26    to the NSP System. In 2037, the model defers a combustion turbine (CT)

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1 addition. In 2038, the cost of the Change Case increases slightly due to a  
2 battery storage resource being pulled forward in the model. In the 2039-2040  
3 timeframe, the costs of additional CTs are partially offset by deferred wind  
4 additions. Beyond 2040, similar fluctuations in the sets of resources added or  
5 deferred in a given year result in cost spikes up or down through the end of  
6 the analysis period in 2045.

7  
8 Q. DOES THE NORTHERN WIND PROJECT MERELY GENERATE FLUCTUATIONS IN  
9 REVENUE REQUIREMENT OR DOES IT GENERATE NET SAVINGS?

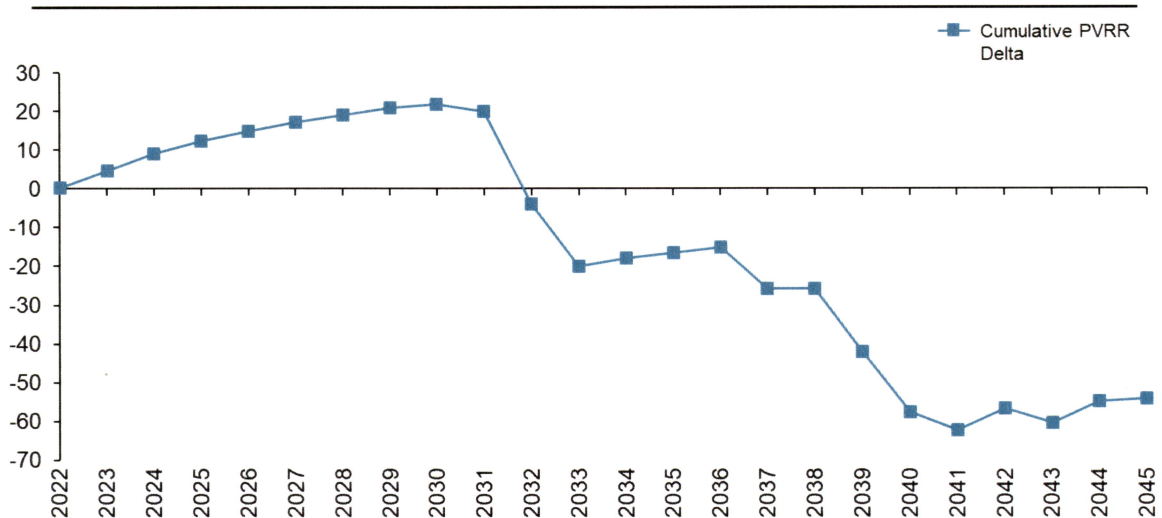
10 A. As I noted earlier, the addition of the Northern Wind project generates net  
11 benefits of between \$39 million and \$62 million PVRR over the 2020-2045  
12 analysis period. Figure 2 below shows the cumulative savings generated by the  
13 Northern Wind acquisition over time under our base assumptions, which  
14 generates \$54 million in savings on a PVRR basis. Figure 2 indicates that the  
15 fluctuations in the annual revenue requirement of the Change Case relative to  
16 the Base Case do not negate the overall savings generated.

17

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1 **Figure 2: Cumulative Cost/(Savings) of Northern Wind vs the Base Case**

**Cumulative annual cost/(savings) of the Northern Wind Project, relative to the Base Case**  
\$ millions



2

3

4 Q. WHAT DOES FIGURE 2 SHOW?

5 A. Figure 2 shows that modest incremental costs accrued in the near term are  
6 expected to be offset fully by the early 2030s and subsequently, none of the  
7 year over year spikes in cost are large enough in magnitude to reverse this  
8 cumulative savings picture. These savings are generated by tax benefits,  
9 deferral of future capacity additions, and replacement of higher-cost fuel  
10 sources on the NSP System with Northern Wind.

11

12 Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

13 A. I conclude that the Northern Wind acquisition will provide material cost  
14 savings to the NSP System when considered as part of the Company's broader  
15 portfolio of wind repowering projects as proposed in Case No. PU-20-425.

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1 Q. HISTORICALLY, THE COMPANY HAS PROVIDED A RATE IMPACT ANALYSIS WITH  
2 ITS ADP APPLICATIONS. WHY WAS SUCH AN ANALYSIS NOT INCLUDED WITH  
3 THIS APPLICATION?

4 A. The Company's EnCompass modelling indicates that the Northern Wind  
5 acquisition will reduce costs and result in customer savings. Accordingly, we  
6 concluded that a rate impact analysis was not necessary. However, if the  
7 Commission desires such an analysis, we would be happy to provide one  
8 during discovery.

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11

**III. CONCLUSION**

12 Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

13 A. The Company's proposed acquisition of the repowered and expanded  
14 Northern Wind project is prudent. Our economic analysis showed that the  
15 acquisition will provide substantial cost saving benefits for customers as part  
16 of the Company's broader repowering portfolio. Specifically, we estimate that  
17 the Northern Wind acquisition will save customers approximately \$54 million  
18 on a PVRR basis. Thus, the proposed acquisition is prudent and reasonable,  
19 and the Commission should grant an ADP.

20

21 Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

22 A. Yes, it does.



**Schedule 1  
Farah L. Mandich  
Statement of Qualifications**

Farah Ladan Mandich is a Specialist, Resource Planning for Northern States Power Company – Minnesota. She currently works within the Company’s Resource Planning team on the development of resource plans and acquisitions for the NSP System, which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. Mandich joined Xcel Energy in April 2019 as a Regulatory Policy Specialist, where she was responsible for developing resource planning and resource acquisition regulatory filings for NSP-M.

Prior to joining Xcel Energy, Mandich was a Policy Advisor at Southern California Edison (SCE), a large investor owned utility in California. In this role, she supported development of Integrated Resource Planning and resource acquisition regulatory filings before the California Public Utilities Commission. Before working on California regulatory issues, Mandich was a Knowledge Specialist in global consultancy McKinsey & Company’s Electric Power & Natural Gas practice, where she served as a subject matter expert to both US and international clients on North American renewable energy markets.

Mandich received her Bachelor of Science in Economics from Texas Christian University and her Master of Public Policy from the University of Michigan’s Gerald R. Ford School of Public Policy.

**MODELING ASSUMPTIONS AND INPUTS**

Since filing our initial Resource Plan in July 2019 in Case No. PU-19-220, the Company has made several changes to its modeling approaches, inputs, and assumptions for the purposes of developing our Supplement Preferred Plan.

<b>Topic</b>	<b>Assumption</b>	<b>Change from Initial IRP Filing</b>
<b><i>Modeling constraints</i></b>		
Carbon emissions constraint	<ul style="list-style-type: none"> <li>▪ No constraint; baseload scenarios may not meet 80 percent reduction goal</li> </ul>	<ul style="list-style-type: none"> <li>▪ Removed modeling constraint of 80 percent carbon reduction by 2030</li> </ul>
“No Going Back” wind replacement capacity	<ul style="list-style-type: none"> <li>▪ No assumption that existing wind will be replaced when plants or contracts reach end of life</li> </ul>	<ul style="list-style-type: none"> <li>▪ Removed wind replacement capacity from baseline modeling</li> </ul>
Reliability Requirement	<ul style="list-style-type: none"> <li>▪ Modeling does not include 5.7 GW firm, dispatchable capacity floor; model optimizes resources to develop expansion plans</li> </ul>	<ul style="list-style-type: none"> <li>▪ Removed reliability requirement from baseline modeling</li> </ul>

**NORTHERN STATES POWER COMPANY  
 ADVANCE DETERMINATION OF PRUDENCE –  
 ACQUISITION OF 120 MW NORTHERN WIND**

<b>Topic</b>	<b>Assumption</b>	<b>Change from Initial IRP Filing</b>
Near term wind availability constraint	<ul style="list-style-type: none"> <li>No generic wind option made available for model to select before 2026</li> </ul>	<ul style="list-style-type: none"> <li>Generic wind available to select in modeling for each year</li> </ul>
Market sales limit	<ul style="list-style-type: none"> <li>Limits market sales to 25 percent of retail load in EnCompass modeling</li> </ul>	<ul style="list-style-type: none"> <li>Not applicable; no market sales limit capability in Strategist</li> </ul>
<b><i>Market and technology assumptions</i></b>		
Market hourly price shaping	<ul style="list-style-type: none"> <li>Shaped hourly market prices based on retail load</li> </ul>	<ul style="list-style-type: none"> <li>Hourly market price shaped based on thermal load</li> </ul>
Fuel price forecasts	<ul style="list-style-type: none"> <li>Updated to Fall 2019 forecast vintage</li> </ul>	<ul style="list-style-type: none"> <li>Changed from vintage available prior to previous filing</li> </ul>
Technology price forecasts for wind, solar, and storage	<ul style="list-style-type: none"> <li>Used National Renewable Energy Labs (NREL) <i>Annual Technology Baseline (ATB) 2019</i> assumptions</li> </ul>	<ul style="list-style-type: none"> <li>Updated from 2018 ATB to 2019 ATB for wind and solar</li> <li>Shifted from using internal price assumptions to 2019 ATB for storage</li> </ul>

**NORTHERN STATES POWER COMPANY  
 ADVANCE DETERMINATION OF PRUDENCE –  
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Topic	Assumption	Change from Initial IRP Filing
Wind resource production	<ul style="list-style-type: none"> <li>▪ Used 2019 NREL ATB price inputs for Technology Resource Group (TRG) 2</li> </ul>	<ul style="list-style-type: none"> <li>▪ Previously used 2018 ATB price assumptions for TRG 1, which reflected a higher capacity factor expectation</li> </ul>
Solar resource production	<ul style="list-style-type: none"> <li>▪ Assumed 22 percent capacity factor in first year, with 0.5 percent per year degradation</li> </ul>	<ul style="list-style-type: none"> <li>▪ Previously assumed 17.7 percent levelized capacity factor</li> </ul>
Renewable transmission interconnect cost	<ul style="list-style-type: none"> <li>▪ Wind: \$500/kW</li> <li>▪ Solar: \$200/kW</li> </ul>	<ul style="list-style-type: none"> <li>▪ Wind: Increased from \$400/kW for greenfield wind</li> <li>▪ Solar: Increased from \$140/kW</li> </ul>
Solar capacity accreditation	<ul style="list-style-type: none"> <li>▪ 50 percent ELCC to 2023, declining to 30 percent in 2033 at a rate of 2 percent per year</li> </ul>	<ul style="list-style-type: none"> <li>▪ 50 percent ELCC for the full analysis period</li> </ul>

**NORTHERN STATES POWER COMPANY  
 ADVANCE DETERMINATION OF PRUDENCE –  
 ACQUISITION OF 120 MW NORTHERN WIND**

<b>Topic</b>	<b>Assumption</b>	<b>Change from Initial IRP Filing</b>
Wind capacity accreditation	<ul style="list-style-type: none"> <li>▪ 16.7 percent ELCC throughout the planning period</li> </ul>	<ul style="list-style-type: none"> <li>▪ 15.6 percent ELCC throughout the planning period</li> </ul>
Effective Reserve Margin	<ul style="list-style-type: none"> <li>▪ Reserve margin updated to 3.46 percent, based on latest MISO LOLE Study (2020-2021)</li> </ul>	<ul style="list-style-type: none"> <li>▪ 2.98 percent effective reserve margin</li> </ul>
<b><i>Upper Midwest System Assumptions</i></b>		
Unit retirement dates	<ul style="list-style-type: none"> <li>▪ All existing unit retirement years with end of financial life</li> </ul>	<ul style="list-style-type: none"> <li>▪ Selected units used differing retirement dates for resource planning purposes</li> </ul>
Seasonal coal dispatch	<ul style="list-style-type: none"> <li>▪ King and Sherco 2 do not dispatch from March-May and September-November, through 2023</li> </ul>	<ul style="list-style-type: none"> <li>▪ No units were modeled with seasonal dispatch</li> </ul>
Load forecasts	<ul style="list-style-type: none"> <li>▪ Updated to fall 2019 internal forecast vintage</li> </ul>	<ul style="list-style-type: none"> <li>▪ Changed from fall 2018 internal forecast</li> </ul>

Topic	Assumption	Change from Initial IRP Filing
DER forecasts	<ul style="list-style-type: none"> <li>▪ Updated to latest vintage for each technology</li> </ul>	<ul style="list-style-type: none"> <li>▪ Changed from vintage available prior to previous filing</li> </ul>
EV adoption forecasts	<ul style="list-style-type: none"> <li>▪ Updated to latest vintage, aligned with most recent forecasts used in IDP</li> </ul>	<ul style="list-style-type: none"> <li>▪ Changed from vintage available prior to previous filing</li> </ul>
Nuclear budgets	<ul style="list-style-type: none"> <li>▪ Updated to most recent vintage for Nuclear Decommissioning Trust, Operations and Maintenance and Capital Expenditure budgets</li> </ul>	<ul style="list-style-type: none"> <li>▪ Changed from vintage available prior to previous filing</li> </ul>

In addition to these modifications for the IRP Supplement, we have made several additional model updates for the instant docket, to account for inclusion of resources that have been recently approved by the North Dakota Public Service Commission (NDPSC) and/or Minnesota Public Utilities Commission (MPUC). These changes are consistent with those made for the Company’s filing in Case No. PU-20-425, and they include:

- Adjusting the Mower County Wind resource to reflect both the ND PSC and MPUC approval of our repowering and purchase proposal;<sup>1</sup>
- The addition of a 100 MW Deuel Harvest Wind and 80 MW Elk Creek Solar PPAs that support our Minnesota Renewable\*Connect program expansion (the costs of which will recovered directly from participating customers in Minnesota);
- Updating baseline revenue requirement assumptions for the four Company-owned wind projects considered in this proposal;

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<sup>1</sup> Per Case No. PU-19-310.

**NORTHERN STATES POWER COMPANY**  
**ADVANCE DETERMINATION OF PRUDENCE –**  
**ACQUISITION OF 120 MW NORTHERN WIND**

- Updating baseline cost and operational assumptions for the third-party wind projects proposed; and
- Updating how we model curtailments; whereas we previously only assigned energy costs to generation net of curtailment, we now also account for costs of energy that is ultimately curtailed.

Further, for the purposes of modeling the costs and benefits of the Northern Wind Project, the Company has further incorporated into the Base Case the four wind projects for which we submitted an Application for Advance Determination of Prudence in Case No. PU-20-425. These Projects, as well as one other PPA under 50 MW, were approved by the Minnesota Public Utilities Commission in Docket No. E002/M-20-620 on January 21, 2021.

As a result of these updates, the Base Case expansion plan used as a comparison point for assessing the Northern Wind project’s economic costs/benefits is slightly altered relative to the IRP’s Supplement Preferred Plan and the Wind Repower Base used in Case No. PU-20-425. The Base Case expansion plan used in modeling for this Application is detailed below.

**Northern Wind Application Base Case**

<b>Wind Repower Base Case (MW)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>2029</b>	<b>2030</b>	<b>2031</b>	<b>2032</b>	<b>2033</b>	<b>2034</b>
Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Firm Peaking	-	-	-	-	-	-	-	-	-	-	374	748	374	748	374
CC	-	-	-	-	-	-	-	835	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	750	750	750
Solar	-	-	-	-	-	500	500	-	-	1,500	500	-	-	-	-
DR	33	132	67	62	47	41	12	14	15	17	19	20	21	22	24
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Distributed Solar	173	72	87	68	25	16	15	15	15	15	15	15	15	15	15
<b>TOTAL</b>	<b>321</b>	<b>334</b>	<b>269</b>	<b>263</b>	<b>214</b>	<b>702</b>	<b>681</b>	<b>1,022</b>	<b>185</b>	<b>1,672</b>	<b>1,045</b>	<b>919</b>	<b>1,145</b>	<b>1,520</b>	<b>1,145</b>

**A. Discount Rate and Capital Structure**

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.47 percent. The rates shown below were calculated by taking a weighted average of each NSP jurisdiction’s last allowed/settled electric retail rate case.

**Table IV-1: Discount Rate and Capital Structure<sup>2</sup>**

<b>Discount Rate and Capital Structure</b>				
	<b>Capital Structure</b>	<b>Allowed Return</b>	<b>Before Tax Electric WACC</b>	<b>After Tax Electric WACC</b>
Long-Term Debt	45.72%	4.79%	2.19%	1.58%
Common Equity	52.39%	9.25%	4.85%	4.85%
Short-Term Debt	1.89%	3.55%	0.07%	0.05%
<b>Total</b>			<b>7.10%</b>	<b>6.47%</b>

**B. Inflation Rates**

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The general inflation rate of 2 percent is from their long-term forecast for “Chained Price Index for Total Personal Consumption Expenditures” published in the second quarter of 2018.

**C. Reserve Margin**

The reserve margin at the time of MISO’s peak is 8.9 percent from the 2020-2021 LOLE Study Report, published November 2019. The coincidence factor between the NSP System and MISO system peak is 95 percent. Therefore, the effective reserve margin is:

$$(95 \text{ percent coincidence factor}) \times (1 + 8.9 \text{ percent}) - 1 = 3.46 \text{ percent effective reserve margin for NSP}$$

**D. CO<sub>2</sub> Costs**

The Present Value of Societal Cost (PVSC) Base Case CO<sub>2</sub> values are based on the high environmental cost values for CO<sub>2</sub> through 2024 (page 31 of the Minnesota

<sup>2</sup> Note: the Tables in this Schedule retain their numbering from our most recent Integrated Resource Plan.

**NORTHERN STATES POWER COMPANY**  
**ADVANCE DETERMINATION OF PRUDENCE –**  
**ACQUISITION OF 120 MW NORTHERN WIND**

Case No. PU-21-\_\_\_\_  
Exhibit\_\_\_\_(FLM-1), Schedule 2  
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Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.). All prices are converted to 2018 real dollars using the 2017 Gross Domestic Product Implicit Price Deflator (GDPIPD) of 113.416 and then escalated at general inflation thereafter.

The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs (see page 12 of MPUC Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No. E999/CI-07-1199 and E999/DI-17-53 issued June 11, 2018). All prices escalate at general inflation.

The Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs requires four alternative scenarios to be run in addition to the PVSC Base Case. The Order Extending Deadline for Filing Next Resource Plan issued January 30, 2019 also requires a scenario using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below.

Table IV-2: CO<sub>2</sub> Costs

CO2 Costs (\$ per short ton)						
Year	Low Environmental Cost	High Environmental Cost	Low Environmental/Regulatory Costs	Mid Environmental/Regulatory Costs	PVSC - High Environmental/Regulatory Costs	PVRR - Omitting CO2 Cost Considerations
2018	\$9.09	\$42.76	\$9.09	\$25.92	\$42.76	\$0.00
2019	\$9.49	\$44.58	\$9.49	\$27.04	\$44.58	\$0.00
2020	\$9.90	\$46.45	\$9.90	\$28.18	\$46.45	\$0.00
2021	\$10.32	\$48.39	\$10.32	\$29.35	\$48.39	\$0.00
2022	\$10.77	\$50.38	\$10.77	\$30.57	\$50.38	\$0.00
2023	\$11.22	\$52.43	\$11.22	\$31.82	\$52.43	\$0.00
2024	\$11.69	\$54.55	\$11.69	\$33.12	\$54.55	\$0.00
2025	\$12.16	\$56.72	\$5.00	\$15.00	\$25.00	\$0.00
2026	\$12.67	\$58.97	\$5.10	\$15.30	\$25.50	\$0.00
2027	\$13.17	\$61.29	\$5.20	\$15.61	\$26.01	\$0.00
2028	\$13.70	\$63.67	\$5.31	\$15.92	\$26.53	\$0.00
2029	\$14.24	\$66.12	\$5.41	\$16.24	\$27.06	\$0.00
2030	\$14.80	\$68.64	\$5.52	\$16.56	\$27.60	\$0.00
2031	\$15.37	\$71.24	\$5.63	\$16.89	\$28.15	\$0.00
2032	\$15.97	\$73.91	\$5.74	\$17.23	\$28.72	\$0.00
2033	\$16.57	\$76.67	\$5.86	\$17.57	\$29.29	\$0.00
2034	\$17.21	\$79.50	\$5.98	\$17.93	\$29.88	\$0.00
2035	\$17.85	\$82.41	\$6.09	\$18.28	\$30.47	\$0.00
2036	\$18.52	\$85.41	\$6.22	\$18.65	\$31.08	\$0.00
2037	\$19.20	\$88.50	\$6.34	\$19.02	\$31.71	\$0.00
2038	\$19.91	\$91.68	\$6.47	\$19.40	\$32.34	\$0.00
2039	\$20.62	\$94.96	\$6.60	\$19.79	\$32.99	\$0.00
2040	\$21.38	\$98.32	\$6.73	\$20.19	\$33.65	\$0.00
2041	\$22.14	\$101.78	\$6.86	\$20.59	\$34.32	\$0.00
2042	\$22.94	\$105.34	\$7.00	\$21.00	\$35.01	\$0.00
2043	\$23.74	\$109.00	\$7.14	\$21.42	\$35.71	\$0.00
2044	\$24.58	\$112.76	\$7.28	\$21.85	\$36.42	\$0.00
2045	\$25.43	\$116.63	\$7.43	\$22.29	\$37.15	\$0.00
2046	\$26.33	\$120.61	\$7.58	\$22.73	\$37.89	\$0.00
2047	\$27.23	\$124.71	\$7.73	\$23.19	\$38.65	\$0.00
2048	\$28.17	\$128.92	\$7.88	\$23.65	\$39.42	\$0.00
2049	\$29.12	\$133.24	\$8.04	\$24.13	\$40.21	\$0.00
2050	\$30.12	\$137.69	\$8.20	\$24.61	\$41.02	\$0.00
2051	\$31.14	\$142.26	\$8.37	\$25.10	\$41.84	\$0.00
2052	\$32.18	\$146.97	\$8.53	\$25.60	\$42.67	\$0.00
2053	\$33.26	\$151.80	\$8.71	\$26.12	\$43.53	\$0.00
2054	\$34.36	\$156.76	\$8.88	\$26.64	\$44.40	\$0.00
2055	\$35.50	\$161.87	\$9.06	\$27.17	\$45.28	\$0.00
2056	\$36.66	\$167.11	\$9.24	\$27.71	\$46.19	\$0.00
2057	\$37.86	\$172.51	\$9.42	\$28.27	\$47.11	\$0.00

**E. All Other Externality Costs**

The values of the criteria pollutants are derived from the high and low values for each of the three locations, as determined in the Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018. The midpoint externality costs are the average of the low and high values. All prices are escalated to 2018 real dollars using the 2017 GDPIPD of 113.416. The high, low and midpoint externality costs will be used in the CO<sub>2</sub> sensitivities as described above.

**Table IV-3: Externality Costs**

<b>MPUC Low Externality Costs</b>				
<b>2018 \$ per short ton</b>				
	<b>Urban</b>	<b>Metro Fringe</b>	<b>Rural</b>	<b>&lt;200mi</b>
SO <sub>2</sub>	\$6,116	\$4,829	\$3,643	\$0
NO <sub>x</sub>	\$2,934	\$2,622	\$2,110	\$28
PM <sub>2.5</sub>	\$10,697	\$6,856	\$3,654	\$872
CO	\$1.65	\$1.17	\$0.31	\$0.31
Pb	\$4,857	\$2,562	\$624	\$624

<b>MPUC High Externality Costs</b>				
<b>2018 \$ per short ton</b>				
	<b>Urban</b>	<b>Metro Fringe</b>	<b>Rural</b>	<b>&lt;200mi</b>
SO <sub>2</sub>	\$15,288	\$12,030	\$8,878	\$0
NO <sub>x</sub>	\$8,390	\$7,798	\$6,771	\$158
PM <sub>2.5</sub>	\$26,721	\$17,091	\$8,973	\$1,327
CO	\$3.51	\$2.08	\$0.63	\$0.63
Pb	\$6,011	\$3,094	\$695	\$695

<b>MPUC Midpoint Externality Costs</b>				
<b>2018 \$ per short ton</b>				
	<b>Urban</b>	<b>Metro Fringe</b>	<b>Rural</b>	<b>&lt;200mi</b>
SO <sub>2</sub>	\$10,702	\$8,430	\$6,261	\$0
NO <sub>x</sub>	\$5,662	\$5,210	\$4,441	\$93
PM <sub>2.5</sub>	\$18,709	\$11,974	\$6,313	\$1,099
CO	\$2.58	\$1.63	\$0.47	\$0.47
Pb	\$5,434	\$2,828	\$659	\$659

**F. Demand and Energy Forecast**

The Company's fall 2019 load forecast is used as the base assumption and assumes that EV impacts growth continues throughout the forecast period. The energy efficiency (EE) forecast included in the base forecast developed by the Company's Load Forecasting department assumes somewhat less energy efficiency (EE) savings

levels than those included in our initial Resource Plan's Preferred Plan. Please see Attachment A Section II for more information.

The "Load Forecast with EE" shown in Table IV-4 below is the starting point for the load inputs. In all modeling scenarios, the "EE" is removed – the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2048. In the initial filing, the three EE Bundles (discussed below) were optimized as Proview Alternatives. For this supplemental filing, the first two EE Bundles are included in all scenarios. The resulting forecast, before the optimized EE bundles are added, is shown below in Table IV-4 as "Forecast Without EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

**Table IV-4: Demand and Energy Forecast**

<b>Demand and Energy Forecast</b>				
<b>Year</b>	<b>Demand (MW)</b>		<b>Energy (GWh)</b>	
	<b>Forecast with EE</b>	<b>Forecast without EE</b>	<b>Forecast with EE</b>	<b>Forecast without EE</b>
2018	9,152	9,152	43,914	43,914
2019	9,084	9,084	43,558	43,558
2020	9,099	9,230	43,170	43,806
2021	9,079	9,312	42,741	44,018
2022	9,126	9,462	42,628	44,549
2023	9,165	9,604	42,440	45,004
2024	9,184	9,728	42,339	45,555
2025	9,238	9,849	42,324	45,976
2026	9,311	9,992	42,470	46,565
2027	9,414	10,164	42,757	47,296
2028	9,504	10,327	43,221	48,216
2029	9,525	10,416	43,006	48,432
2030	9,605	10,566	43,224	49,093
2031	9,679	10,710	43,420	49,734
2032	9,775	10,880	43,903	50,678
2033	9,979	11,058	44,532	51,299
2034	10,190	11,246	45,426	52,203
2035	10,343	11,269	46,158	52,299
2036	10,502	11,325	47,028	52,527
2037	10,673	11,393	47,647	52,503
2038	10,803	11,420	48,209	52,422
2039	10,936	11,449	48,833	52,394
2040	11,073	11,518	49,603	52,729
2041	11,209	11,585	50,055	52,737
2042	11,338	11,645	50,635	52,873
2043	11,467	11,701	51,267	53,048
2044	11,614	11,780	52,023	53,374
2045	11,722	11,818	52,468	53,375
2046	11,839	11,865	53,010	53,473
2047	11,951	11,903	53,545	53,547
2048	12,021	11,998	54,150	54,160
2049	12,045	12,045	54,202	54,202
2050	12,097	12,097	54,407	54,407
2051	12,149	12,149	54,611	54,611
2052	12,199	12,199	54,947	54,947
2053	12,252	12,252	55,022	55,022
2054	12,305	12,305	55,226	55,226
2055	12,357	12,357	55,431	55,431
2056	12,409	12,409	55,765	55,765
2057	12,461	12,461	55,840	55,840

The low load sensitivity includes high customer-adoption-based DG/DER growth and higher EE savings, which reduces load. The high load sensitivity includes high

electrification load. These assumptions are shown in Table IV-5 and Table IV-6 and are incremental/decremental to the forecast shown in Table IV-4.

**Table IV-5: High Load Sensitivity**

<b>High Electrification</b>		
<b>Year</b>	<b>Energy (GWh)</b>	<b>Demand (MW)</b>
2018	35	8
2019	46	6
2020	59	7
2021	166	20
2022	276	33
2023	390	47
2024	507	62
2025	592	65
2026	692	77
2027	812	85
2028	939	98
2029	1,202	118
2030	1,578	162
2031	2,028	205
2032	2,538	251
2033	3,137	305
2034	3,857	367
2035	4,716	438
2036	5,657	515
2037	6,672	596
2038	7,741	679
2039	8,851	766
2040	9,996	854
2041	11,114	940
2042	12,199	1,025
2043	13,241	1,118
2044	14,229	1,796
2045	15,159	2,520
2046	16,037	3,173
2047	16,877	3,796
2048	17,696	4,647
2049	18,660	4,908
2050	19,530	5,407
2051	20,634	5,947
2052	21,645	6,418
2053	22,656	6,896
2054	23,666	7,384
2055	24,677	7,877
2056	25,688	8,352
2057	26,699	8,840

*\*Demand values are coincident to system peak*

**Table IV- 6: Low Load Sensitivity**

Year	High DER Growth	
	Energy (GWh)	Demand (Nameplate MW)
2018	0	0
2019	0	0
2020	0	0
2021	207	122
2022	180	106
2023	159	94
2024	270	159
2025	258	152
2026	423	250
2027	423	250
2028	635	374
2029	641	379
2030	740	437
2031	826	487
2032	913	538
2033	996	588
2034	1,082	639
2035	1,167	689
2036	1,256	739
2037	1,338	790
2038	1,423	840
2039	1,509	891
2040	1,598	941
2041	1,631	963
2042	1,580	933
2043	1,529	903
2044	1,482	872
2045	1,425	842
2046	1,350	797
2047	1,296	765
2048	1,245	733
2049	1,187	701
2050	1,131	668
2051	1,063	628
2052	1,009	594
2053	932	550
2054	872	515
2055	807	476
2056	742	437
2057	671	396

**G. Energy Efficiency Bundles**

The EE “Program” and “Maximum” Bundles are based on the Minnesota DOC’s Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The “Optimal” Bundle was developed by the Company. The bundles are decremental (reducing energy and demand) to the “Forecast without EE” shown in Table IV-4.

**Table IV- 7: Energy Efficiency Bundles**

Year	Energy(MWh)			Demand (MW)			Costs (\$000)		
	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	621	43	231	97	18	36	100,989	12,598	148,331
2021	1,326	91	493	207	38	77	113,525	13,905	167,221
2022	1,913	148	702	301	60	113	121,239	21,425	177,197
2023	2,555	211	928	407	86	154	133,614	23,931	196,474
2024	3,094	279	1,110	520	116	197	148,406	26,120	217,388
2025	3,629	346	1,289	635	146	241	152,433	26,077	223,293
2026	4,330	414	1,533	759	176	289	160,445	26,236	233,779
2027	5,054	482	1,785	886	206	338	167,718	26,637	242,963
2028	5,785	551	2,040	1,012	235	387	174,161	27,018	249,373
2029	6,454	606	2,280	1,127	259	432	162,170	23,442	233,114
2030	7,110	659	2,516	1,241	283	477	162,170	23,442	233,114
2031	7,753	710	2,748	1,354	307	522	162,170	23,442	233,114
2032	8,339	760	2,960	1,460	329	564	162,170	23,442	233,114
2033	8,909	808	3,168	1,564	352	605	162,170	23,442	233,114
2034	9,464	857	3,370	1,667	374	646	162,170	23,442	233,114
2035	9,250	846	3,294	1,648	370	638	0	0	0
2036	8,739	835	3,073	1,579	366	600	0	0	0
2037	8,088	789	2,829	1,470	347	557	0	0	0
2038	7,450	741	2,590	1,369	327	517	0	0	0
2039	6,841	685	2,372	1,267	304	475	0	0	0
2040	6,197	626	2,144	1,154	278	430	0	0	0
2041	5,543	562	1,919	1,036	250	384	0	0	0
2042	4,871	499	1,685	916	221	337	0	0	0
2043	4,220	434	1,457	796	191	291	0	0	0
2044	3,561	377	1,218	678	165	245	0	0	0
2045	2,912	318	990	562	139	201	0	0	0
2046	2,276	265	761	451	116	156	0	0	0
2047	1,746	212	573	349	93	117	0	0	0
2048	1,216	159	384	248	70	79	0	0	0
2049	686	106	195	146	46	40	0	0	0
2050	156	53	7	45	23	1	0	0	0
2051	0	0	0	0	0	0	0	0	0
2052	0	0	0	0	0	0	0	0	0
2053	0	0	0	0	0	0	0	0	0
2054	0	0	0	0	0	0	0	0	0
2055	0	0	0	0	0	0	0	0	0
2056	0	0	0	0	0	0	0	0	0
2057	0	0	0	0	0	0	0	0	0

*\*\*Demand values are coincident to system peak*

**H. Demand Response Forecast**

The base demand response forecast was developed by the Company and is included in all scenarios and sensitivities. The three demand response “Bundles” are from the Brattle Potential Study provided as Appendix G2. The Bundles are incremental to the base demand response forecast. In the initial filing, the three DR Bundles were optimized as Proview Alternatives. For this Supplement, the first DR Bundle is included in all scenarios.

**Table IV-8: Demand Response Forecast**

Year	Demand (MW)				Costs (\$000)		
	Adjusted For Reserve Margin				Bundle 1	Bundle 2	Bundle 3
	Base Demand Response Forecast	Bundle 1	Bundle 2	Bundle 3			
2018	852	0	0	0	0	0	0
2019	928	0	0	0	0	0	0
2020	1012	33	107	90	1,752	7,659	11,311
2021	1027	165	112	98	8,917	8,150	12,587
2022	1041	232	117	107	12,748	8,676	14,016
2023	1055	294	121	110	16,489	9,137	14,758
2024	1066	341	133	101	19,512	10,277	13,829
2025	1072	382	145	92	22,305	11,459	12,858
2026	1077	394	152	93	23,475	12,207	13,326
2027	1078	407	159	95	24,786	13,080	13,845
2028	1077	423	168	97	26,245	14,086	14,418
2029	1071	440	178	99	27,859	15,231	15,047
2030	1059	458	190	102	29,637	16,522	15,734
2031	1048	478	202	104	31,551	17,926	16,467
2032	1037	499	215	107	33,612	19,451	17,251
2033	1026	521	228	110	35,832	21,109	18,088
2034	1016	545	243	113	38,224	22,911	18,984
2035	1005	570	259	116	40,802	24,870	19,943
2036	995	596	275	120	43,582	26,999	20,971
2037	985	624	293	123	46,580	29,313	22,072
2038	976	654	312	127	49,814	31,829	23,253
2039	966	686	332	132	53,305	34,564	24,522
2040	957	720	353	136	57,073	37,537	25,884
2041	948	720	353	136	58,215	38,288	26,402
2042	939	720	353	136	59,379	39,054	26,930
2043	930	720	353	136	60,566	39,835	27,468
2044	922	720	353	136	61,778	40,632	28,018
2045	914	720	353	136	63,013	41,444	28,578
2046	906	720	353	136	64,274	42,273	29,150
2047	898	720	353	136	65,559	43,118	29,733
2048	890	720	353	136	66,870	43,981	30,327
2049	882	720	353	136	68,208	44,860	30,934
2050	875	720	353	136	69,572	45,758	31,552
2051	868	720	353	136	70,963	46,673	32,183
2052	860	720	353	136	72,382	47,606	32,827
2053	853	720	353	136	73,830	48,558	33,484
2054	847	720	353	136	75,307	49,530	34,153
2055	840	720	353	136	76,813	50,520	34,836
2056	833	720	353	136	78,349	51,531	35,533
2057	827	720	353	136	79,916	52,561	36,244

*\*Demand values are coincident to system peak.*

## **I. Fuel Price Forecasts**

Natural gas price forecasts are developed using a blend of market information (New York Mercantile Exchange, or NYMEX, futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five-year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, SO<sub>2</sub> costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. Table IV-9 below shows the market prices under zero CO<sub>2</sub> cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low-price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting when the long-term fundamentally-based forecasts are blended with market information (NYMEX futures prices).

Table IV-9: Fuel and Market Price Forecasts

Year	Base Price Forecast				Low Price Forecast				High Price Forecast			
	Fuel Price (\$/mmBTu)		Market Price (\$/MWh)		Fuel Price (\$/mmBTu)		Market Price (\$/MWh)		Fuel Price (\$/mmBTu)		Market Price (\$/MWh)	
	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2018	\$2.19	\$2.74	\$28.60	\$21.61	\$2.19	\$2.74	\$28.60	\$21.61	\$2.19	\$2.74	\$28.60	\$21.61
2019	\$2.08	\$2.60	\$26.93	\$20.98	\$2.08	\$2.60	\$26.93	\$20.98	\$2.08	\$2.60	\$26.93	\$20.98
2020	\$2.11	\$2.26	\$25.78	\$20.13	\$2.11	\$2.26	\$25.78	\$20.13	\$2.11	\$2.26	\$25.78	\$20.13
2021	\$2.14	\$2.23	\$25.32	\$19.06	\$2.14	\$2.23	\$25.32	\$19.06	\$2.14	\$2.23	\$25.32	\$19.06
2022	\$2.19	\$2.33	\$26.92	\$20.45	\$2.17	\$2.28	\$26.33	\$20.00	\$2.24	\$2.38	\$27.52	\$20.90
2023	\$2.25	\$2.45	\$29.31	\$22.19	\$2.19	\$2.34	\$27.96	\$21.17	\$2.36	\$2.57	\$30.68	\$23.23
2024	\$2.30	\$2.58	\$30.00	\$23.20	\$2.22	\$2.40	\$27.94	\$21.60	\$2.46	\$2.76	\$32.16	\$24.87
2025	\$2.35	\$2.79	\$31.47	\$24.36	\$2.24	\$2.50	\$28.17	\$21.80	\$2.57	\$3.11	\$35.04	\$27.12
2026	\$2.40	\$2.98	\$32.30	\$24.99	\$2.27	\$2.58	\$28.01	\$21.67	\$2.69	\$3.42	\$37.09	\$28.70
2027	\$2.45	\$3.12	\$33.35	\$26.71	\$2.29	\$2.64	\$28.28	\$22.64	\$2.81	\$3.66	\$39.16	\$31.36
2028	\$2.51	\$3.26	\$34.09	\$26.97	\$2.32	\$2.71	\$28.25	\$22.35	\$2.93	\$3.92	\$40.92	\$32.38
2029	\$2.57	\$3.44	\$35.21	\$28.25	\$2.34	\$2.78	\$28.42	\$22.79	\$3.07	\$4.24	\$43.38	\$34.80
2030	\$2.62	\$3.70	\$38.27	\$30.69	\$2.37	\$2.88	\$29.83	\$23.92	\$3.20	\$4.71	\$48.76	\$39.09
2031	\$2.68	\$3.87	\$39.33	\$32.07	\$2.40	\$2.95	\$29.97	\$24.44	\$3.35	\$5.04	\$51.22	\$41.77
2032	\$2.75	\$4.02	\$39.75	\$33.14	\$2.43	\$3.01	\$29.71	\$24.77	\$3.51	\$5.34	\$52.76	\$43.99
2033	\$2.81	\$4.10	\$39.93	\$33.46	\$2.45	\$3.03	\$29.58	\$24.79	\$3.67	\$5.48	\$53.47	\$44.80
2034	\$2.87	\$4.20	\$41.13	\$34.56	\$2.48	\$3.07	\$30.08	\$25.28	\$3.83	\$5.70	\$55.76	\$46.86
2035	\$2.94	\$4.35	\$42.15	\$35.66	\$2.51	\$3.13	\$30.32	\$25.65	\$4.00	\$6.00	\$58.12	\$49.17
2036	\$2.99	\$4.47	\$42.79	\$36.60	\$2.53	\$3.17	\$30.37	\$25.97	\$4.14	\$6.24	\$59.80	\$51.13
2037	\$3.07	\$4.65	\$44.00	\$38.21	\$2.56	\$3.24	\$30.61	\$26.58	\$4.36	\$6.63	\$62.69	\$54.44
2038	\$3.14	\$4.86	\$44.95	\$39.45	\$2.60	\$3.31	\$30.60	\$26.85	\$4.58	\$7.08	\$65.43	\$57.42
2039	\$3.23	\$5.04	\$45.82	\$40.48	\$2.63	\$3.37	\$30.63	\$27.06	\$4.83	\$7.47	\$67.88	\$59.98
2040	\$3.31	\$5.22	\$46.61	\$41.48	\$2.66	\$3.43	\$30.61	\$27.25	\$5.06	\$7.87	\$70.25	\$62.53
2041	\$3.37	\$5.32	\$46.52	\$41.48	\$2.69	\$3.46	\$30.27	\$26.99	\$5.26	\$8.10	\$70.79	\$63.12
2042	\$3.45	\$5.47	\$47.61	\$42.64	\$2.72	\$3.51	\$30.57	\$27.38	\$5.51	\$8.43	\$73.40	\$65.74
2043	\$3.53	\$5.62	\$48.37	\$43.71	\$2.75	\$3.56	\$30.64	\$27.69	\$5.77	\$8.78	\$75.56	\$68.28
2044	\$3.62	\$5.78	\$49.72	\$44.99	\$2.79	\$3.61	\$31.04	\$28.09	\$6.05	\$9.17	\$78.79	\$71.29
2045	\$3.70	\$5.99	\$51.23	\$46.37	\$2.82	\$3.68	\$31.45	\$28.46	\$6.31	\$9.65	\$82.57	\$74.73
2046	\$3.78	\$6.17	\$52.49	\$47.53	\$2.85	\$3.73	\$31.74	\$28.74	\$6.59	\$10.09	\$85.85	\$77.73
2047	\$3.86	\$6.29	\$53.27	\$48.57	\$2.88	\$3.77	\$31.89	\$29.08	\$6.88	\$10.40	\$87.98	\$80.22
2048	\$3.95	\$6.46	\$54.39	\$49.88	\$2.91	\$3.82	\$32.15	\$29.49	\$7.20	\$10.80	\$90.96	\$83.42
2049	\$4.04	\$6.66	\$55.69	\$50.92	\$2.95	\$3.88	\$32.43	\$29.65	\$7.53	\$11.30	\$94.52	\$86.43
2050	\$4.13	\$6.77	\$56.64	\$51.71	\$2.98	\$3.91	\$32.70	\$29.85	\$7.87	\$11.60	\$96.97	\$88.53
2051	\$4.22	\$6.96	\$58.23	\$53.16	\$3.01	\$3.96	\$33.16	\$30.27	\$8.21	\$12.08	\$101.05	\$92.24
2052	\$4.31	\$7.13	\$59.62	\$54.42	\$3.04	\$4.01	\$33.56	\$30.63	\$8.57	\$12.51	\$104.64	\$95.53
2053	\$4.41	\$7.29	\$61.00	\$55.68	\$3.08	\$4.06	\$33.94	\$30.99	\$8.94	\$12.95	\$108.29	\$98.85
2054	\$4.50	\$7.46	\$62.38	\$56.95	\$3.11	\$4.10	\$34.33	\$31.34	\$9.33	\$13.39	\$111.97	\$102.21
2055	\$4.60	\$7.62	\$63.76	\$58.21	\$3.14	\$4.15	\$34.71	\$31.69	\$9.73	\$13.83	\$115.69	\$105.61
2056	\$4.69	\$7.79	\$65.15	\$59.47	\$3.17	\$4.19	\$35.09	\$32.03	\$10.12	\$14.28	\$119.45	\$109.05
2057	\$4.79	\$7.95	\$66.53	\$60.73	\$3.21	\$4.24	\$35.46	\$32.37	\$10.52	\$14.74	\$123.26	\$112.52

\*Coal prices are delivered prices, while gas and market prices are hub prices.

**J. Baseload Retirement “Leave Behind” Costs**

Based on the MISO Y2 retirement studies performed on existing coal and nuclear resources, the Company developed transmission reinforcement or “leave behind” estimates, which reflect costs required to mitigate localized grid impacts of the retirement of major baseload resources. The reinforcement costs are included as a one-time charge based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated from the MISO studies. We applied these costs in the modeling as soon as the resource is retired, over a three-year period, to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms (\$2020).

- King: \$48 million
- Sherco 3: \$48 million
- Monticello: \$96 million
- Prairie Island 1: \$96 million
- Prairie Island 2: \$96 million

**K. Surplus Capacity Credit**

The surplus capacity credit of up to 500 MW is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic brownfield H-Class combustion turbine on an economic carrying charge basis.

**Table IV-10: Surplus Capacity Credit**

Surplus Capacity Credit																				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
\$/kw-mo	4.57	4.66	4.75	4.85	4.95	5.05	5.15	5.25	5.35	5.46	5.57	5.68	5.80	5.91	6.03	6.15	6.27	6.40	6.53	6.66
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
\$/kw-mo	6.79	6.93	7.07	7.21	7.35	7.50	7.65	7.80	7.96	8.12	8.28	8.44	8.61	8.79	8.96	9.14	9.32	9.51	9.70	9.89

**L. Effective Load Carrying Capability Capacity Credit for Wind, Solar, and Battery Resources**

The ELCC for existing wind units is based on current MISO accreditation. The ELCC for generic wind is equal to 16.7 percent of their nameplate rating per MISO 2020/2021 Wind Capacity Report. The ELCC for generic solar is based on the values

provided in MISO’s MTEP 2019 in Appendix E,<sup>3</sup> and is 50 percent of the alternating current (AC) nameplate capacity through 2023, declining 2 percent annually to 30 percent by 2033 where it remains for the rest of the forecast period. The ELCC assigned for a generic 4-hour battery is equal to 100 percent of the AC equivalent capacity. The ELCC used for hybrid options are the same as the individual components.

### **M. Spinning Reserve Requirement**

Spinning reserve is the online reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 137 MW and is based on a 12-month rolling average of spinning reserves carried by the NSP System within MISO.

### **N. Emergency Energy**

Emergency energy is used to cover events where there are not enough resources or market purchase energy available to meet system energy requirements. In Strategist, this is set to \$500/MWh. Encompass uses the default value of \$10,000/MWh. The primary reason for this difference is the way the models utilize this input. In Strategist’s dispatch approach, the emergency energy is determined after the dispatch, when all resources have been utilized and an energy shortfall still exists. In EnCompass, emergency energy is a “soft constraint” that allows emergency energy to “dispatch” as a last resort resource, in order for the model to find a feasible solution. The EnCompass price is set to a high level to ensure that all other available resources – including those that may have a very high effective \$/MWh cost resulting from startup costs spread over a very small required run time – are utilized before emergency energy.

### **O. Transmission Delivery Costs and Interconnection Costs**

Transmission delivery costs for generic resources were developed by the Company. They are based on evaluation of recent and historical MISO studies and queue results. These costs represent “grid upgrades” to ensure deliverability of energy from these facilities to the overall bulk electric system.

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<sup>3</sup> Available at: <https://cdn.misoenergy.org//MTEP19%20Appendix%20E-Futures%20Assumptions382958.pdf>

We note additionally that interconnection costs for generic resources are included in the capital costs in Table IV-14 in Part U of this section and represent “behind the fence” costs associated with substation and representative gen-tie construction.

**Table IV-11: Transmission Delivery Costs**

<b>Transmission Delivery Costs</b>				
	<b>CC</b>	<b>CT</b>	<b>Wind</b>	<b>Solar</b>
<b>\$/kw</b>	500	200	500	200

**P. Integration and Congestion Costs**

Integration costs are taken from studies conducted by Enernex and apply to new wind and solar resources only. Congestion costs were not included in the model.

**Table IV-12: Integration Costs**

<b>Integration Costs (\$/MWh)</b>		
<b>Year</b>	<b>Wind</b>	<b>Solar</b>
2018	0.00	0.00
2019	0.00	0.00
2020	0.41	0.41
2021	0.42	0.42
2022	0.43	0.43
2023	0.44	0.44
2024	0.45	0.45
2025	0.46	0.46
2026	0.47	0.47
2027	0.48	0.48
2028	0.49	0.49
2029	0.49	0.49
2030	0.50	0.50
2031	0.51	0.51
2032	0.53	0.53
2033	0.54	0.54
2034	0.55	0.55
2035	0.56	0.56
2036	0.57	0.57
2037	0.58	0.58
2038	0.59	0.59
2039	0.60	0.60
2040	0.62	0.62
2041	0.63	0.63
2042	0.64	0.64
2043	0.65	0.65
2044	0.67	0.67
2045	0.68	0.68
2046	0.69	0.69
2047	0.71	0.71
2048	0.72	0.72
2049	0.74	0.74
2050	0.75	0.75
2051	0.77	0.77
2052	0.78	0.78
2053	0.80	0.80
2054	0.81	0.81
2055	0.83	0.83
2056	0.84	0.84
2057	0.86	0.86

**Q. Distributed Solar Generation and Community Solar Gardens**

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts. Distributed Solar is modeled assuming a degradation of

half a percent annually in generation. Community Solar Gardens are modeled assuming a degradation of half a percent annually in generation, and a twenty-five-year service life. After a “vintage” of additions reach end of life, it is assumed 90% of the capacity is replaced at then-current costs.

**Table IV-13: Distributed Solar Forecast**

<b>Distributed Solar (Nameplate MW)</b>			
<b>Year</b>	<b>Solar Rewards</b>	<b>Community Gardens</b>	<b>Total</b>
2018	29	246	274
2019	61	504	565
2020	80	658	738
2021	95	714	809
2022	109	787	897
2023	123	841	964
2024	138	852	989
2025	152	853	1,005
2026	166	854	1,020
2027	180	855	1,035
2028	194	857	1,050
2029	208	858	1,066
2030	222	859	1,080
2031	236	860	1,095
2032	249	861	1,110
2033	263	862	1,125
2034	276	863	1,140
2035	290	864	1,154
2036	303	866	1,169
2037	317	867	1,184
2038	330	868	1,198
2039	343	869	1,212
2040	357	870	1,227
2041	370	871	1,241
2042	383	869	1,252
2043	396	852	1,247
2044	409	830	1,239
2045	421	818	1,239
2046	434	814	1,248
2047	447	808	1,255
2048	460	805	1,264
2049	472	805	1,277
2050	491	806	1,297
2051	504	807	1,311
2052	518	808	1,326
2053	531	809	1,340
2054	545	810	1,355
2055	559	811	1,369
2056	572	812	1,384
2057	586	812	1,398

**R. Owned Unit Modeled Operating Characteristics and Costs**

Company-owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

- a. Retirement Date
- b. Maximum Capacity
- c. Current Unforced Capacity (UCAP) Ratings
- d. Minimum Capacity Rating
- e. Seasonal Deration
- f. Heat Rate Profiles
- g. Variable O&M
- h. Fixed O&M
- i. Maintenance Schedule
- j. Forced Outage Rate
- k. Emission rates for SO<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, Mercury and particulate matter (PM)
- l. Contribution to spinning reserve
- m. Fuel prices
- n. Fuel delivery charges

**S. Thermal PPA Operating Characteristics and Costs**

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

- a. Contract term
- b. Maximum Capacity
- c. Minimum Capacity Rating
- d. Seasonal Deration
- e. Heat Rate Profiles
- f. Energy Schedule
- g. Capacity Payments
- h. Energy Payments
- i. Maintenance Schedule
- j. Forced Outage Rate
- k. Emission rates for SO<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, Mercury and PM
- l. Contribution to spinning reserve
- m. Fuel prices
- n. Fuel delivery charges

## **T. Renewable Energy (PPAs and Owned) Operating Characteristics and Costs**

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each renewable energy unit.

- a. Contract term
- b. Name Plate Capacity
- c. Accredited Capacity
- d. Annual Energy
- e. Hourly Patterns
- f. Capacity and Energy Payments
- g. Integration Costs

Wind and solar hourly patterns are developed through a “Typical Meteorological Year” process where individual months are selected from the years 2017-2020 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each unit. For units where generation data is not complete or not available, data from a nearby similar unit is used.

## **U. Generic Assumptions**

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. Generic renewable and battery costs are based on data from the NREL 2019 ATB. Utility-scale wind and solar costs shown in Tables IV-18 through IV-20 include transmission costs from Table IV-11 while DG/distributed solar does not.

The modeling no longer assumes “no going back” on renewables, which was the replacement of renewable resources for a similar resource when they reached the end of their life, but rather allows all renewable additions to be optimized.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind, solar, and battery costs are also based on the 2019 ATB data. Below is a list of typical operating and cost inputs for each generic resource.

**NORTHERN STATES POWER COMPANY  
ADVANCE DETERMINATION OF PRUDENCE –  
ACQUISITION OF 120 MW NORTHERN WIND**

Case No. PU-21-\_\_\_\_  
Exhibit\_\_\_\_(FLM-1), Schedule 2  
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**NORTHERN STATES POWER COMPANY  
ADVANCE DETERMINATION OF PRUDENCE –  
ACQUISITION OF 120 MW NORTHERN WIND**

Case No. PU-21-\_\_\_\_  
Exhibit\_\_\_\_(FLM-1), Schedule 2  
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Thermal

- a. Retirement Date
- b. Maximum Capacity
- c. UCAP Ratings
- d. Minimum Capacity Rating
- e. Seasonal Deration
- f. Heat Rate Profiles
- g. Variable O&M
- h. Fixed O&M
- i. Maintenance Schedule
- j. Forced Outage Rate
- k. Emission rates for SO<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub>, Mercury and PM
- l. Contribution to spinning reserve
- m. Fuel prices
- n. Fuel delivery charges

Renewable

- a. Contract term
- b. Name Plate Capacity
- c. Accredited Capacity
- d. Annual Energy
- e. Hourly Patterns
- f. Capacity and Energy Payments
- g. Integration Costs

**Table IV-14: Thermal Generic Information (Costs in 2018 Dollars)**

<b>Thermal Generic Information</b>					
<b>Resource</b>	<b>Sherco CC</b>	<b>Generic CC</b>	<b>Generic CT</b>	<b>Generic CT</b>	<b>Generic CT</b>
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	835	901	374	232	374
Summer Peak Capacity (MW)	750	856	331	206	331
Capital Cost (\$000) 2018\$	\$837,068	\$906,588	\$174,700	\$114,766	\$193,500
Electric Transmission Delivery (\$000) 2018\$	NA	\$410,505	NA	NA	\$74,804
Ongoing Capital Expenditures (\$000-yr) 2018\$	\$6,200	\$6,200	\$1,784	\$892	\$1,784
Gas Demand (\$000-yr) 2018\$	\$31,725	\$19,058	\$2,165	\$1,342	\$2,165
Capital Cost (\$/kW) 2018\$	\$1,002	\$1,006	\$467	\$495	\$517
Electric Transmission Delivery (\$/kW) 2018\$	NA	\$455	NA	NA	\$200
Ongoing Capital Expenditures (\$/kW-yr) 2018\$	\$7.42	\$6.88	\$4.77	\$3.85	\$4.77
Gas Demand (\$/kW-yr) 2018\$	\$37.98	\$21.14	\$5.79	\$5.79	\$5.79
Fixed O&M Cost (\$000/yr) 2018\$	\$6,592	\$6,592	\$1,253	\$1,203	\$1,253
Variable O&M Cost (\$/MWh) 2018\$	\$1.04	\$1.04	\$0.99	\$1.03	\$0.99
Levelized \$/kw-mo (All Fixed Costs) \$2018	\$15.26	\$16.06	\$5.91	\$6.22	\$8.06
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,848	9,264	10,025	9,264
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,874	9,738	10,581	9,738
Summer Heat Rate 50% Loading (btu/kWh)	6,985	7,334	11,120	12,515	11,120
Summer Heat Rate 25% Loading (btu/kWh)	8,004	8,404	11,558	13,430	11,558
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.90	0.32	0.90
PM10 Emissions (lbs/MWh)	0.02	0.02	0.03	0.03	0.03
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00	0.00

**Table IV-15: Renewable Generic Information (Costs in 2018 Dollars)**

<b>Renewable Generic Information</b>				
<b>Resource</b>	<b>Wind</b>	<b>Utility Scale Solar</b>	<b>Distributed Solar Commercial</b>	<b>Distributed Solar Residential</b>
ELCC Capacity Credit (%)	16.7%	50% declines to 30%		
Capacity Factor	50.0%	22.0%	18.0%	18.0%
Book life	25	25	25	25
Electric Transmission Delivery (\$/kW)	500	200	0	0

**Table IV-16: Storage Generic Information (Costs in 2018 Dollars)**

<b>Storage Generic Information</b>	
<b>Resource</b>	<b>Battery</b>
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	321
Summer Peak Capacity (MW)	321
Storage Volume (hrs)	4
Cycle Efficiency (%)	85
Equivalent Full Cycles per Year	250
Electric Transmission Delivery (\$000) 2018\$	0
Levelized \$/kw-mo (All Fixed Costs) \$2023	\$18.18

Table IV-17: Levelized Capacity Costs by Year

Levelized Capacity Costs by In-Service Year (\$/kw-mo)								
COD	CT - 7H Greenfield	CT - 7F Brownfield	CT - 7H Brownfield	CC	Sherco CC	Base Battery	Low Battery	High Battery
2018	\$8.06	\$6.22	\$5.91	\$16.06	\$15.26			
2019	\$8.22	\$6.34	\$6.02	\$16.38	\$15.56			
2020	\$8.38	\$6.47	\$6.15	\$16.71	\$15.87	\$20.04	\$17.86	\$22.94
2021	\$8.55	\$6.60	\$6.27	\$17.05	\$16.19	\$19.44	\$16.81	\$23.19
2022	\$8.72	\$6.73	\$6.39	\$17.39	\$16.51	\$18.82	\$15.73	\$23.45
2023	\$8.89	\$6.86	\$6.52	\$17.73	\$16.85	\$18.18	\$14.62	\$23.71
2024	\$9.07	\$7.00	\$6.65	\$18.09	\$17.18	\$17.52	\$13.47	\$23.97
2025	\$9.25	\$7.14	\$6.78	\$18.45	\$17.53	\$16.84	\$12.30	\$24.24
2026	\$9.44	\$7.28	\$6.92	\$18.82	\$17.88	\$16.63	\$11.75	\$24.51
2027	\$9.63	\$7.43	\$7.06	\$19.20	\$18.23	\$16.41	\$11.18	\$24.78
2028	\$9.82	\$7.58	\$7.20	\$19.58	\$18.60	\$16.19	\$10.60	\$25.06
2029	\$10.02	\$7.73	\$7.34	\$19.97	\$18.97	\$15.95	\$10.00	\$25.34
2030	\$10.22	\$7.88	\$7.49	\$20.37	\$19.35	\$15.71	\$9.38	\$25.62
2031	\$10.42	\$8.04	\$7.64	\$20.78	\$19.74	\$15.83	\$9.38	\$26.06
2032	\$10.63	\$8.20	\$7.79	\$21.19	\$20.13	\$15.94	\$9.37	\$26.50
2033	\$10.84	\$8.36	\$7.95	\$21.62	\$20.53	\$16.04	\$9.36	\$26.94
2034	\$11.06	\$8.53	\$8.11	\$22.05	\$20.94	\$16.15	\$9.35	\$27.40
2035	\$11.28	\$8.70	\$8.27	\$22.49	\$21.36	\$16.26	\$9.33	\$27.86
2036	\$11.50	\$8.88	\$8.44	\$22.94	\$21.79	\$16.36	\$9.31	\$28.32
2037	\$11.73	\$9.05	\$8.60	\$23.40	\$22.23	\$16.46	\$9.28	\$28.80
2038	\$11.97	\$9.24	\$8.78	\$23.87	\$22.67	\$16.56	\$9.25	\$29.28
2039	\$12.21	\$9.42	\$8.95	\$24.34	\$23.12	\$16.65	\$9.21	\$29.78
2040	\$12.45	\$9.61	\$9.13	\$24.83	\$23.59	\$16.74	\$9.17	\$30.27
2041	\$12.70	\$9.80	\$9.31	\$25.33	\$24.06	\$16.83	\$9.13	\$30.78
2042	\$12.96	\$10.00	\$9.50	\$25.83	\$24.54	\$16.76	\$9.00	\$30.97
2043	\$13.22	\$10.20	\$9.69	\$26.35	\$25.03	\$16.66	\$8.85	\$31.12
2044	\$13.48	\$10.40	\$9.88	\$26.88	\$25.53	\$16.55	\$8.70	\$31.25
2045	\$13.75	\$10.61	\$10.08	\$27.42	\$26.04	\$16.42	\$8.53	\$31.35
2046	\$14.02	\$10.82	\$10.28	\$27.96	\$26.56	\$16.26	\$8.35	\$31.41
2047	\$14.30	\$11.04	\$10.49	\$28.52	\$27.09	\$16.08	\$8.16	\$31.44
2048	\$14.59	\$11.26	\$10.70	\$29.09	\$27.64	\$15.88	\$7.95	\$31.42
2049	\$14.88	\$11.48	\$10.91	\$29.68	\$28.19	\$15.65	\$7.73	\$31.35
2050	\$15.18	\$11.71	\$11.13	\$30.27	\$28.75	\$15.39	\$7.49	\$31.23
2051	\$15.48	\$11.95	\$11.35	\$30.88	\$29.33	\$15.70	\$7.64	\$31.85
2052	\$15.79	\$12.19	\$11.58	\$31.49	\$29.91	\$16.01	\$7.79	\$32.49
2053	\$16.11	\$12.43	\$11.81	\$32.12	\$30.51	\$16.33	\$7.95	\$33.14
2054	\$16.43	\$12.68	\$12.05	\$32.76	\$31.12	\$16.66	\$8.10	\$33.80
2055	\$16.76	\$12.93	\$12.29	\$33.42	\$31.75	\$16.99	\$8.27	\$34.48
2056	\$17.10	\$13.19	\$12.54	\$34.09	\$32.38	\$17.33	\$8.43	\$35.17
2057	\$17.44	\$13.45	\$12.79	\$34.77	\$33.03	\$17.68	\$8.60	\$35.87

**Table IV-18: Base Renewable Levelized Costs by Year**

<b>Levelized Costs by First Full Year of Operation \$/MWh (LCOE)</b>				
	<b>Wind</b>	<b>Utility Scale Solar</b>	<b>Distributed Solar Commercial</b>	<b>Distributed Solar Residential</b>
2018				
2019				
2020	\$28.29	\$46.12	\$61.16	\$92.16
2021	\$32.32	\$48.12	\$64.63	\$94.44
2022	\$36.53	\$53.73	\$74.07	\$105.71
2023	\$40.91	\$53.81	\$73.54	\$102.31
2024	\$36.03	\$53.87	\$72.96	\$98.77
2025	\$50.24	\$53.93	\$72.35	\$95.07
2026	\$50.28	\$53.97	\$71.70	\$91.23
2027	\$50.32	\$53.99	\$71.00	\$87.23
2028	\$50.36	\$54.01	\$70.26	\$83.07
2029	\$50.41	\$54.00	\$69.47	\$78.75
2030	\$50.46	\$53.98	\$68.64	\$74.26
2031	\$51.13	\$54.60	\$69.31	\$74.25
2032	\$51.81	\$55.21	\$69.97	\$74.23
2033	\$52.50	\$55.83	\$70.64	\$74.17
2034	\$53.19	\$56.45	\$71.31	\$74.08
2035	\$53.89	\$57.07	\$71.98	\$73.96
2036	\$54.60	\$57.70	\$72.65	\$73.81
2037	\$55.31	\$58.32	\$73.32	\$73.62
2038	\$56.03	\$58.96	\$73.98	\$73.40
2039	\$56.76	\$59.59	\$74.65	\$73.15
2040	\$57.49	\$60.23	\$75.31	\$72.86
2041	\$58.23	\$60.94	\$75.87	\$73.52
2042	\$58.98	\$61.66	\$76.42	\$74.18
2043	\$59.73	\$62.38	\$76.97	\$74.84
2044	\$60.49	\$63.10	\$77.51	\$75.49
2045	\$61.26	\$63.83	\$78.04	\$76.15
2046	\$62.03	\$64.57	\$78.56	\$77.43
2047	\$62.81	\$65.31	\$79.08	\$78.73
2048	\$63.60	\$66.05	\$79.58	\$80.05
2049	\$64.39	\$66.80	\$80.08	\$81.40
2050	\$65.19	\$67.55	\$80.56	\$82.76
2051	\$66.49	\$68.90	\$82.17	\$84.42
2052	\$67.82	\$70.28	\$83.81	\$86.11
2053	\$69.17	\$71.69	\$85.49	\$87.83
2054	\$70.56	\$73.12	\$87.20	\$89.59
2055	\$71.97	\$74.58	\$88.94	\$91.38
2056	\$73.41	\$76.08	\$90.72	\$93.20
2057	\$74.88	\$77.60	\$92.54	\$95.07

*\*Distributed Solar costs represent at the meter values before grossing up for losses.*

**Table IV-19: Low Renewable Levelized Costs by Year**

<b>Low Levelized Costs by First Full Year of Operation \$/MWh (LCOE)</b>				
	<b>Wind</b>	<b>Utility Scale Solar</b>	<b>Distributed Solar Commercial</b>	<b>Distributed Solar Residential</b>
2018				
2019				
2020	\$25.70	\$40.39	\$46.57	\$80.57
2021	\$28.96	\$41.44	\$44.77	\$80.58
2022	\$32.43	\$45.30	\$50.58	\$87.80
2023	\$36.12	\$44.66	\$49.46	\$82.47
2024	\$30.57	\$43.99	\$48.30	\$76.99
2025	\$44.15	\$43.29	\$47.11	\$71.34
2026	\$43.59	\$42.57	\$45.87	\$65.52
2027	\$43.05	\$41.82	\$44.59	\$59.54
2028	\$42.55	\$41.04	\$43.26	\$53.38
2029	\$42.07	\$40.23	\$41.89	\$47.05
2030	\$41.62	\$39.40	\$40.48	\$40.54
2031	\$42.10	\$39.43	\$40.22	\$40.29
2032	\$42.57	\$39.45	\$39.94	\$40.02
2033	\$43.05	\$39.46	\$39.63	\$39.73
2034	\$43.53	\$39.45	\$39.30	\$39.41
2035	\$44.01	\$39.43	\$38.95	\$39.06
2036	\$44.50	\$39.59	\$38.57	\$38.69
2037	\$44.98	\$39.74	\$38.16	\$38.29
2038	\$45.47	\$39.88	\$37.72	\$37.86
2039	\$45.96	\$40.01	\$37.25	\$37.41
2040	\$46.45	\$40.14	\$36.75	\$36.92
2041	\$46.94	\$40.51	\$37.10	\$37.03
2042	\$47.43	\$40.89	\$37.46	\$37.13
2043	\$47.92	\$41.26	\$37.81	\$37.22
2044	\$48.41	\$41.63	\$38.17	\$37.31
2045	\$48.90	\$42.01	\$37.15	\$37.38
2046	\$49.40	\$42.47	\$37.76	\$37.91
2047	\$49.89	\$42.93	\$38.38	\$38.45
2048	\$50.38	\$43.40	\$39.01	\$39.00
2049	\$50.88	\$43.87	\$39.65	\$39.55
2050	\$51.37	\$44.34	\$40.30	\$40.11
2051	\$52.40	\$45.23	\$41.10	\$40.92
2052	\$53.44	\$46.13	\$41.93	\$41.74
2053	\$54.51	\$47.06	\$42.76	\$42.57
2054	\$55.60	\$48.00	\$43.62	\$43.42
2055	\$56.71	\$48.96	\$44.49	\$44.29
2056	\$57.85	\$49.94	\$45.38	\$45.18
2057	\$59.01	\$50.94	\$46.29	\$46.08

*\*Distributed Solar costs represent at the meter values before grossing up for losses.*

**Table IV-20: High Renewable Levelized Costs by Year**

<b>High Levelized Costs by First Full Year of Operation \$/MWh (LCOE)</b>				
	<b>Wind</b>	<b>Utility Scale Solar</b>	<b>Distributed Solar Commercial</b>	<b>Distributed Solar Residential</b>
2018				
2019				
2020	\$31.34	\$47.98	\$68.45	\$98.01
2021	\$36.42	\$50.93	\$73.59	\$105.38
2022	\$41.69	\$58.00	\$86.61	\$124.02
2023	\$47.16	\$59.16	\$88.34	\$126.50
2024	\$43.38	\$60.35	\$90.11	\$129.03
2025	\$58.71	\$61.55	\$91.91	\$131.61
2026	\$59.88	\$62.79	\$93.75	\$134.24
2027	\$61.08	\$64.04	\$95.63	\$136.93
2028	\$62.30	\$65.32	\$97.54	\$139.67
2029	\$63.55	\$66.63	\$99.49	\$142.46
2030	\$64.82	\$67.96	\$101.48	\$145.31
2031	\$66.11	\$69.32	\$103.51	\$148.22
2032	\$67.43	\$70.71	\$105.58	\$151.18
2033	\$68.78	\$72.12	\$107.69	\$154.20
2034	\$70.16	\$73.56	\$109.85	\$157.29
2035	\$71.56	\$75.03	\$112.04	\$160.43
2036	\$72.99	\$76.53	\$114.28	\$163.64
2037	\$74.45	\$78.07	\$116.57	\$166.91
2038	\$75.94	\$79.63	\$118.90	\$170.25
2039	\$77.46	\$81.22	\$121.28	\$173.66
2040	\$79.01	\$82.84	\$123.70	\$177.13
2041	\$80.59	\$84.50	\$126.18	\$180.67
2042	\$82.20	\$86.19	\$128.70	\$184.29
2043	\$83.85	\$87.91	\$131.28	\$187.97
2044	\$85.52	\$89.67	\$133.90	\$191.73
2045	\$87.23	\$91.47	\$136.58	\$195.57
2046	\$88.98	\$93.30	\$139.31	\$199.48
2047	\$90.76	\$95.16	\$142.10	\$203.47
2048	\$92.57	\$97.06	\$144.94	\$207.54
2049	\$94.43	\$99.01	\$147.84	\$211.69
2050	\$96.31	\$100.99	\$150.79	\$215.92
2051	\$98.24	\$103.01	\$153.81	\$220.24
2052	\$100.20	\$105.07	\$156.89	\$224.65
2053	\$102.21	\$107.17	\$160.02	\$229.14
2054	\$104.25	\$109.31	\$163.23	\$233.72
2055	\$106.34	\$111.50	\$166.49	\$238.40
2056	\$108.46	\$113.73	\$169.82	\$243.16
2057	\$110.63	\$116.00	\$173.22	\$248.03

*\*Distributed Solar costs represent at the meter values before grossing up for losses.*

**V. Market Purchases and Sales Carbon Rate**

In order to estimate emissions rates associated with market purchases, the Company assumes an annual average carbon emissions pounds/MWh rate, as shown in the table below. These estimates were developed using MISO’s MTEP Futures modeling results. Market sales emissions rates reflect an average emissions rate for our system resources and vary according to each individual scenario and sensitivity capacity expansion portfolio.

**Table IV-21: Market Purchase Carbon Rate**

<b>Market Purchase CO2 Rate</b>																				
	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>2029</b>	<b>2030</b>	<b>2031</b>	<b>2032</b>	<b>2033</b>	<b>2034</b>	<b>2035</b>	<b>2036</b>	<b>2037</b>
lbs/MWh	1372	1307	1241	1176	1110	1045	1042	1039	1036	1034	1031	1018	1006	993	980	968	955	943	930	917
	<b>2038</b>	<b>2039</b>	<b>2040</b>	<b>2041</b>	<b>2042</b>	<b>2043</b>	<b>2044</b>	<b>2045</b>	<b>2046</b>	<b>2047</b>	<b>2048</b>	<b>2049</b>	<b>2050</b>	<b>2051</b>	<b>2052</b>	<b>2053</b>	<b>2054</b>	<b>2055</b>	<b>2056</b>	<b>2057</b>
lbs/MWh	905	892	880	867	854	842	829	817	804	792	779	766	754	741	729	716	703	691	678	666

**W. Sherco CC Size Alternatives**

In its October 17, 2019 hearing in this docket, the Commission directed the Company to model different size alternatives for the planned Sherco CC. The Company developed three size alternatives – two smaller units and one larger unit – to test in sensitivity modeling. Cost and performance assumptions for each of these alternatives are detailed in Table IV-22 below.

**Table IV-22: Sherco CC Alternatives**

<b>Thermal Generic Information</b>				
<b>Resource</b>	<b>Sherco CC</b>	<b>7HA.01 1x1</b>	<b>7HA.02 1x1</b>	<b>7HA.02 2x1</b>
Technology	7H	7H	7H	7F
Location Type	Brownfield	Brownfield	Brownfield	Brownfield
Cooling Type	Wet	Wet	Wet	Wet
Book life	40	40	40	40
Nameplate Capacity (MW)	835	405	592	1202
Summer Peak Capacity (MW)	750	395	576	1170
Capital Cost (\$000) 2018\$	\$837,068	\$473,751	\$629,206	\$941,199
Electric Transmission Delivery (\$000) 2018\$	NA	NA	NA	NA
Ongoing Capital Expenditures (\$000-yr) 2018\$	\$6,200	\$4,190	\$4,190	\$8,775
Gas Demand (\$000-yr) 2018\$	\$31,723	\$31,723	\$31,723	\$31,723
Capital Cost (\$/kW) 2018\$	\$1,002	\$1,171	\$1,064	\$783
Electric Transmission Delivery (\$/kW) 2018\$	NA	NA	NA	NA
Ongoing Capital Expenditures (\$/kW-yr) 2018\$	\$7.43	\$10.35	\$7.08	\$7.30
Gas Demand (\$/kW-yr) 2018\$	\$37.99	\$78.41	\$53.63	\$26.38
Fixed O&M Cost (\$000/yr) 2018\$	\$6,592	\$7,150	\$7,150	\$8,647
Variable O&M Cost (\$/MWh) 2018\$	\$1.04	\$1.72	\$1.72	\$1.09
Levelized \$/kw-mo (All Fixed Costs) \$2018	\$15.26	\$18.36	\$14.11	\$10.95
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,322	6,208	6,452
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,419	6,257	6,403
Summer Heat Rate 50% Loading (btu/kWh)	6,985	6,681	6,516	6,812
Summer Heat Rate 25% Loading (btu/kWh)	8,004	7,553	7,388	7,479
Forced Outage Rate	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	5	5
CO2 Emissions (lbs/MMBtu)	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.05	0.05
PM10 Emissions (lbs/MWh)	0.02	0.02	0.02	0.02
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00