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Direct Testimony and Schedule
Philip Joseph "P.J." Martin

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 98.9 MW Mower County Wind Facility

Case No. PU-19-____
Exhibit___(PJM-1)

Resource Planning

August 30, 2019

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Prefiled Direct Testimony of Phillip Joseph Martin - Redacted
Northern States Power Company
Zeviel Simpser - Dorsey & Whitney LLP

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Schedule

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Philip Joseph "P.J." Martin. I am the Director, Resource Planning, for Northern States Power Company – Minnesota (NSP or Xcel Energy or the Company).

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since August of 2015 in the areas of Strategic Asset Planning and Resource Planning. In my first role at Xcel Energy in the Strategic Asset Planning group, I focused primarily on business planning for the four operating companies at Xcel Energy. I assumed my current role as Director, Resource Planning in October of 2016.

Prior to joining Xcel Energy, I worked as a Portfolio Director and Energy Trader at ACES Power Marketing. In these roles, I engaged in trading and wholesale portfolio management activities on behalf of electric cooperatives, municipal utilities, IPPs, banks, and other customers. I also supported long-term planning and risk management efforts for these customers in the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, LLC, SERC, and other markets across the U.S.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I am responsible for the direction of electric resource planning for the five-state integrated Northern States Power Company system (NSP System), which provides electric service to customers in North

Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. This includes assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources. Among other things, I oversee our resource planning efforts using Strategist to conduct economic evaluations of potential resource additions, and oversee bid processes for new resource acquisitions.

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

A. The purpose of my testimony is to discuss, in detail, the economic impacts of the proposed acquisition of the Mower County Wind Facility. My testimony supports the conclusion that the North Dakota Public Service Commission (Commission) should grant an advance determination of prudence (ADP) for the proposed transaction. My testimony provides an economic analysis of the proposed transaction and the overall ratepayer benefits it generates.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- Section II discusses the Economic Analysis conducted by the Company on the Mower County Wind Facility; and
- Section III sets forth my Conclusions with regard to the application.

II. ECONOMIC ANALYSIS

Q. HOW DID THE COMPANY EVALUATE THE COST-EFFECTIVENESS OF THE MOWER COUNTY WIND FACILITY TRANSACTION?

A. The Company performed two economic analyses to evaluate the present value of revenue requirements (PVRR) impacts of the acquisition of the Mower County Wind Facility: (1) a pro forma modeling approach, and (2) a traditional analysis using the Strategist resource planning model (Strategist).

A. Pro Forma Model Approach and Results

Q. WHAT IS A PRO FORMA MODELING ANALYSIS?

A. A pro forma analysis is a simple way to isolate the anticipated costs or benefits of making changes to a specific resource without engaging in full system production cost and expansion plan modeling. This approach 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. In general, the pro forma model provides us a simpler view of the economic costs or benefits of a project, based on revenue requirements, than the Strategist modeling described below. We often use this modeling internally, as an initial indication of whether a project likely results in customer benefits, prior to or alongside conducting Strategist modeling.

Q. IS THE PRO FORMA ANALYSIS AN APPROPRIATE TOOL FOR EVALUATING WIND PROJECTS?

A. Yes. The pro forma analysis is appropriate for wind resources because they produce zero marginal cost or "must take" energy that is generally predictable from year to year and not subject to fluctuations driven by the dispatch of different resources on our system. With known production levels, we can simply compare the costs of one option (Power Purchase Agreement, or PPA, with generic wind replacement) to the costs of another (resource acquisition). While adding incremental wind energy would have larger impacts on the system and potentially impact the dispatch of other resources, here we are assuming the same levels of wind in both cases, which allows us to focus on the cost deltas.

Q. How did the Company use pro forma modeling to analyze the proposed acquisition of the Mower County Wind Facility?

A. To perform the pro forma analysis, we input Project-specific cost and operational information in order to evaluate the costs of the repowering and acquisition, in comparison to a baseline where the existing PPA is continued and later replaced with generic wind when the PPA expires. To compare the two options' costs on an equal basis, we made two adjustments to the baseline.

First, because the repowering will use newer, more efficient equipment, it is expected to generate over **[*TRADE SECRET BEGINS***
TRADE SECRET ENDS] more energy annually than the existing Facility. So, to make an "apples-to-apples" comparison, we include incremental generic wind energy and associated costs in the baseline to account for the incremental value of the wind energy provided by the repower in excess of the PPA volumes.

Second, in order to model the baseline on a comparable basis with the acquisition after 2026, we assume a generic wind PPA replaces the full output of the repowered resource after the existing contract expires in 2026, through 2045. We assume a term for both options through 2045 because this is the expected useful life of the Mower County Wind Facility, once the repowering is completed. Making these two adjustments allows us to reasonably compare the proposed acquisition to the alternative scenario in which we would retain the PPA and later contract the same amount of wind energy from another seller upon PPA expiration.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S PRO FORMA ANALYSIS OF THE PROPOSED ACQUISITION?

A. The pro forma analysis indicates that the proposed acquisition of the repowered Facility results in PVRR benefits of approximately $48 million over the life of the Facility. Our analysis estimates that the levelized cost of energy resulting from the acquisition at the agreed-upon purchase price is ***[TRADE SECRET BEGINS TRADE SECRET ENDS]***, which is significantly lower than the ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** levelized cost of the existing PPA and generic wind replacement through the end of the modeling period.

B. Strategist Analysis Approach and Results

Q. WHAT IS STRATEGIST?

A. Strategist is a modeling program that simulates the operation of the NSP System and estimates the total cost of energy over the life of a project on a present value basis. Strategist can be used to test results under a range of input assumptions, also known as sensitivities. The Company uses this tool, which is industry standard, for the majority of its resource planning efforts. Compared to the pro forma analysis, Strategist helps us evaluate proposed acquisitions in the broader context of the integrated NSP System and our most recent Integrated Resource Plan's Preferred Plan by fully evaluating the impacts of the Mower options relative to our entire resource portfolio.

Q. HOW DID THE COMPANY USE STRATEGIST TO ANALYZE THE PROPOSED ACQUISITION OF THE MOWER COUNTY WIND FACILITY?

A. For this analysis, the Company simulated the operation of the NSP System through 2045, with and without the acquisition of the 98.9 MW Mower County Wind Facility. As with the pro forma analysis, we performed our Strategist modeling through 2045 because this is the expected useful life of the repowered Facility.

Q. WHAT DID THE COMPANY'S MODELING USE AS THE "BASE CASE" FOR COMPARATIVE ANALYSIS?

A. We evaluated the Project using our most recent Upper Midwest Integrated Resource Plan's (IRP) Preferred Plan as our Base Case. The Company filed its IRP with the Commission on July 1, 2019, and it has been assigned Case No. 19-220.

Q. WHAT DOES THE BASE CASE ASSUME WILL HAPPEN ONCE THE CURRENT PPA EXPIRES IN 2026?

A. The Base Case assumes that the wind energy purchased under the existing PPA will be replaced with a generic wind PPA starting at $38.81/MWh that escalates at 2 percent through 2045, after the current contract term ends in December 2026 and continuing through the end of the analysis period. The estimated levelized cost of the existing PPA and generic replacement wind is ***[TRADE SECRET BEGINS TRADE SECRET ENDS]***. This modeling approach is consistent with the Company's plans to pursue renewable replacement generation on the NSP System, as set forth in our recently-filed IRP.

Q. AT A HIGH LEVEL, WHAT WERE THE RESULTS OF THE COMPANY'S STRATEGIST MODELING OF THE MOWER COUNTY ACQUISITION?

A. The results of the Strategist analysis show that the purchase of the Mower County Facility under the terms of the executed Purchase and Sale Agreement is expected to result in net savings for our customers system-wide of approximately $48.8 million on a PVRR basis, when compared with the Base Case. The Strategist analysis indicates that the transaction will generate savings for customers under all sensitivities modeled.

Q. IN GENERAL, WHAT IS THE SOURCE OF THE SAVINGS ASSOCIATED WITH THE MOWER COUNTY ACQUISITION?

A. At the agreed-upon purchase price of the Mower County Facility, it is more cost effective for the Company to acquire, own, and operate the repowered Facility than it is to replace its 98.9 MW of capacity with a generic wind PPA upon expiration of the current contract. This is because, as I noted earlier, the levelized cost of energy over the expected 25-year life of the repowered Facility is approximately $11/MWh lower than the cost of the existing PPA and generic wind in the years after the PPA expires.

C. Carbon-Free Energy Objective

Q. WHAT IS THE COMPANY'S STRATEGY WITH REGARD TO RENEWABLES IN THE IRP?

A. The Company's Preferred Plan in our most recent IRP reflects a "no going back" approach to renewable resources on the NSP System, in pursuit of our commitment to carbon-free energy. Under this approach, the Company will seek to remain at or above the current level of renewable generation serving the NSP System. This is a key component in our efforts to sustain our progress in integrating substantial amounts of cost-effective renewable energy into our portfolio and to achieve our stated long-term carbon reduction goals.

Q. HOW IS THIS APPROACH IMPLEMENTED IN THE IRP?

A. Our IRP Preferred Plan adds approximately 1,200 MW of generic new wind generation onto the NSP System by 2034, which equates to approximately 5,270 gigawatt hours (GWh) annually by 2034. This is the amount needed to replace the wind resources currently on the NSP System that will reach the end of their contract or operating lives within the IRP planning window.

Q. WHAT IS THE COMPANY'S RATIONALE FOR ADOPTING THIS RENEWABLES STRATEGY?

A. The Company has proactively committed to reducing our carbon emissions across the Xcel Energy footprint 80 percent below 2005 levels by 2030, and ultimately to provide carbon-free energy by 2050. The strategy set forth in our Preferred Plan is an effort to continue toward this ambitious goal by ensuring we will not fall below our current level of renewables as older renewable projects reach the end of their useful lives or PPAs expire.

Q. CAN REPOWERING OLDER RENEWABLE FACILITIES BE A PART OF THE COMPANY'S CARBON-FREE ENERGY COMMITMENT STRATEGY?

A. Certainly. Repowering and purchasing aging renewable facilities, as the Company is proposing to do with Mower County, is a cost effective way to extend the lives of these resources and keep them on the NSP System. Further, the significant transmission constraints associated with greenfield renewable projects often mean that it is more cost effective and efficient to keep current renewable generation on the NSP System rather than letting it retire or expire.

Q. HOW IS THIS APPROACH TO RENEWABLES REFLECTED IN THE COMPANY'S MODELING?

A. As noted above, in the Preferred Plan all renewable resources on the NSP System will be replaced by an equivalent amount of renewable generation at the end of the resource's useful life or upon expiration of an existing PPA. Thus when our IRP Preferred Plan is used as the Base Case, our modeling assumes that existing wind and solar resources that are coming off the System will be replaced by generic wind and solar resources, respectively.

Q. WHAT DOES USING THE IRP'S PREFERRED PLAN AS THE BASE CASE MEAN FOR THE COMPANY'S ANALYSIS OF THE PROJECT?

A. Application of the Preferred Plan to the modeling of this transaction means that the Strategist model assumed replacement of the existing Mower

County PPA with a generic wind PPA upon its expiration in December 2026. Typically, Strategist would replace the existing capacity with a resource the model determines is the cheapest resource at the time that the existing PPA expires. However, given that "wind-for-wind" replacement is assumed in the Preferred Plan, the Base Case adopts this same assumption and assigns a generic wind PPA starting at $38.81/MWh to replace the existing PPA in the Base Case.

Q. WHY IS THE COST OF THE REPLACEMENT GENERIC PPA HIGHER THAN THE COST OF ACQUIRING THE FACILITY?

A. As I noted, the Strategist model determined that the initial cost of the replacement generic PPA, beginning service in December 2026, would be $38.81/MWh, and we have assumed it inflates at 2 percent annually, resulting in a levelized price of ***[TRADE SECRET BEGINS***
TRADE SECRET ENDS] through 2045. This number is higher than we might expect for a generic wind resource today for two primary reasons. First, the replacement PPA is assumed to not have the benefit of the federal Production Tax Credit (PTC), which will be fully phased out by the time any new project will come online. In the 2019 tax year, the PTC is 2.5 cents/kWh, or $25/MWh. Second, the model includes a $400/kW transmission delivery cost for new generic wind additions, in order to account for the persistent backlog in the MISO interconnection queue and likely interconnection costs associated with greenfield wind. Based on recent MISO queue studies, transmission delivery costs for generic wind may be higher than the costs we assumed in modeling, which further reinforces the value of repowering projects, such as Mower, that have existing interconnection rights. It should be noted that the forecasted future wind

prices used for generic wind resources in the IRP were derived from the NREL Annual Technology Baseline, which is an independent third party source widely used for forecasted resource cost projections in the industry.

Q. PLEASE ELABORATE ON THE TRANSMISSION CHALLENGES ASSOCIATED WITH GREENFIELD WIND PROJECTS.

A. Recent developments in the MISO Definitive Planning Phase (DPP) underscore the challenges associated with pursuing incremental greenfield wind resources, and the value of securing or extending resources with existing interconnection agreements. MISO recently completed Phase 2 of the DPP that began in February 2017, which contained over 1,300 MW of wind projects in the West region. In early August, however, all but one MISO West region wind project in the study group withdrew from the queue, as a result of a study identifying significant system upgrade costs that would be required for these projects to interconnect – on average, approximately $2 million per MW. One of the withdrawn projects is the final phase of the Company's Crowned Ridge wind project, although the Company is working to identify alternate paths forward.

Q. WHAT DOES THIS CONSTRAINED TRANSMISSION ACCESS MEAN FOR THE MOWER COUNTY FACILITY?

A. We believe that this development is a concrete illustration of increasing barriers to bringing incremental wind resources online in the Upper Midwest. Repowering projects such as the Mower County Facility – that already have generator interconnection agreements in place – therefore provide additional value in the current market environment and will help us maintain affordability. We believe that acquiring the Mower County Facility, and its existing interconnection rights, is prudent, particularly in the context of the Company's IRP Preferred Plan discussed above.

Q. WHAT OTHER ASSUMPTIONS DID THE COMPANY INPUT INTO THE STRATEGIST MODELING FOR THIS TRANSACTION?

A. The Company's analysis assumes the addition of the 1,850 MW of wind deemed prudent under the Commission's December 6, 2018, Order Approving Settlement in Case Nos. PU-17-120 and PU-17-372. The full list of Strategist assumptions used in our modeling of the Mower County repowering and acquisition is attached hereto as Exhibit___(PJM-1), Schedule 1.

D. Strategist Results

Q. HOW DID THE COMPANY APPROACH ITS EVALUATION OF THE PROJECT USING THE STRATEGIST TOOL?

A. As noted above, we evaluated the Project assuming our most recent IRP's Preferred Plan as our "Base Case." We evaluated the economic costs and benefits of the Project as a partial fulfillment of the wind replacement need identified in the IRP, rather than as an incremental resource, because we envision Mower County being a part of achieving the 1,200 MW total wind needed in the planning period under our IRP Preferred Plan.

Q. WHAT WERE THE RESULTS OF THE STRATEGIST ANALYSIS?

A. The results of the Strategist analysis show that the purchase of the Facility under the terms of the Purchase and Sale Agreement (PSA) is expected to result in net savings for our customers of approximately $48.8 million on a PVRR basis. The analysis assumes the Project is operational for 25 years and will be eligible to receive 100 percent of the existing renewable PTC, as noted above. Table 1 below shows the components of the overall PVRR result.

Table 1
PVRR Impact by Cost Category ($2019 millions)

Cost Category	PVRR Impact ($2019 millions)
Mower PPA/Generic Wind PPA (post-2026) Payments	(184.8)
Market Transactions	(6.2)
Fuel	(2.4)
Variable O&M	(0.4)
Acquisition-related Expenses	145.0
Total	**(48.8)**

Q. WHAT OTHER SENSITIVITIES DID THE COMPANY MODEL IN DEVELOPING THE ANALYSIS OF THE PROJECT?

A. The Company modeled several sensitivities to test the benefits of purchasing the Facility under different potential future market conditions, including variation around fuel prices and interactions with the MISO energy market. We also modeled the Facility acquisition in a "markets off" scenario, under which we assume we will not be able to sell excess capacity into MISO. The results of these analyses are presented in Table 2 below, which shows that the Mower acquisition results in PVRR benefits in all sensitivities presented.

Table 2
PVRR Impact by Sensitivity Relative to the Base Case

Market Sensitivity Case	PVRR Impact ($2019 millions)
Baseline (no CO_2 Costs)	(48.8)
Low Gas and Coal Prices	(48.3)
High Gas and Coal Prices	(49.4)
No Market Sales	(44.6)

Q. WHY DID THE COMPANY MODEL THESE ADDITIONAL SENSITIVITIES?

A. In light of the Project repowering extending its operational life and adding wind generation to the NSP System, the Project may have an effect on how other plants in the system are dispatched and the opportunity for generation on the Company's system to exceed our native load-serving requirement. Therefore we include sensitivities that test PVRR impacts with different fuel prices and ability to sell excess energy to the market. For the fuel cost sensitivities, we test both high and low natural gas and coal prices, consistent with sensitivity modeling used in our Resource Plan. Regarding market sales, when our generation exceeds our native load serving requirement, the Company is likely to make energy sales into the MISO market. Revenues from these sales will be credited to consumers through the Company's Fuel Cost Rider (FCR). Therefore, assumptions regarding the likely value of the potential energy sales into the MISO market are an important factor in predicting the likely rate impact of the proposed Mower County acquisition.

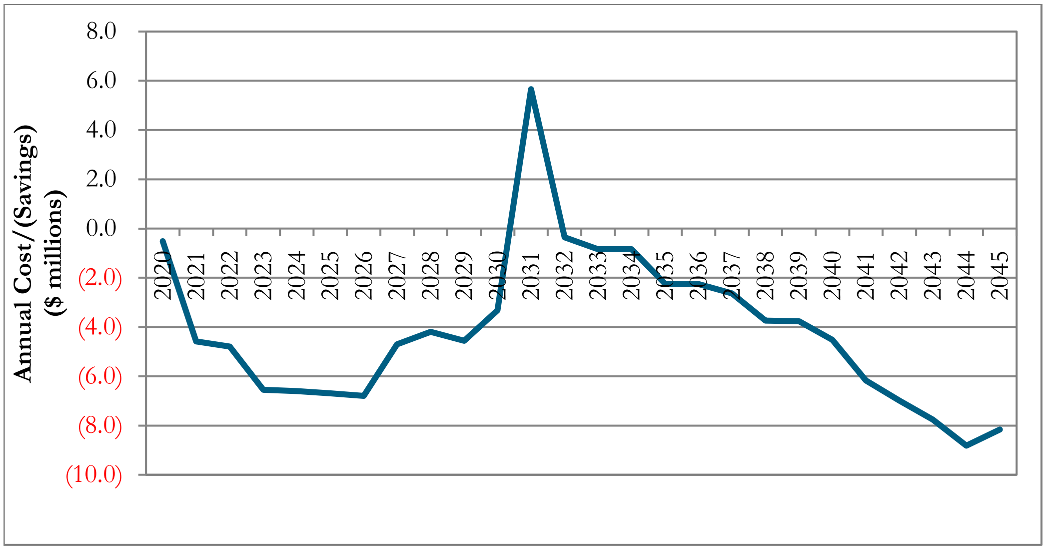
Q. PLEASE DESCRIBE THE HIGH AND LOW GAS AND COAL PRICE SENSITIVITIES.

A. The Company's natural gas and coal price forecasts are based on a blend of the latest market information and long-term fundamentals-based forecasts acquired from third parties. As I stated previously, the Company has included low and high natural gas and coal sensitivities to evaluate the impacts of variations in the prices of these fuels on the proposed transaction.

Q. DID THE COMPANY ANALYZE HOW COST SAVINGS EVOLVE OVER THE LIFE OF THE PROJECT?

A. Yes. To understand how the costs and/or savings change over time, we also examined the proposed repowering and acquisition costs on an annual basis. Figure 1 shows the annual NSP system cost impacts of the Mower County repower and acquisition compared to the Base Case where the existing PPA is sustained through its term and replaced with generic wind energy thereafter. This analysis shows savings accruing to customers in most years. The increase in costs shown in the 2030-31 timeframe is driven by the expiration of the PTC. After 2031, however, customers see savings each year from the Company's lower cost of ownership of the Facility, as compared to new generic wind costs.

Figure 1
Annual Costs/(Savings) of Repower and PSA
Compared to the Base Case
($ millions)



E. Estimated Customer Rate Impacts

Q. WHAT IS THE ESTIMATED IMPACT OF ACQUIRING MOWER COUNTY ON THE RATES PAID BY THE COMPANY'S NORTH DAKOTA CUSTOMERS?

A. The Company expects that customers' overall bills will be lower as a result of the proposed repowering and acquisition of the Facility, relative to the Base Case. Based on the results of the Company's Strategist modeling, the cost of the Company owning and operating the Project will be offset by decreases from the avoided PPA purchases.

Q. HOW DID THE COMPANY REACH THIS CONCLUSION?

A. To develop the bill impact analysis, the Company began with the incremental savings, relative to the Base Case, as determined by the Strategist modeling discussed above. Specifically, the Company used the outputs from the PVRR sensitivity including market interactions. Using the annual system-wide costs impact from Strategist, the Company then applied a jurisdictional allocator based on our current sales forecast to determine the costs allocated to the North Dakota jurisdiction. Jurisdictional costs were then allocated to classes based on class cost of service study allocation factors approved in the Company's last North Dakota rate case order.

Q. HOW WILL EXPECTED CHANGES IN REVENUE REQUIREMENTS BE REFLECTED ON NORTH DAKOTA CUSTOMERS' BILLS?

A. Table 3, below, shows the forecasted incremental impact on average monthly bills in North Dakota.

Table 3
Estimated Impact of PSA on
Average Monthly Bills in North Dakota ($)

Year	Residential	Small Commercial (Non-Demand Metered)	Large Commercial (Demand Metered)
2020	0.01	0.01	0.47
2021	(0.02)	(0.04)	(1.21)
2022	(0.04)	(0.06)	(2.18)
2023	(0.08)	(0.13)	(4.55)
2024	(0.08)	(0.13)	(4.62)
2025	(0.09)	(0.15)	(5.05)
2026	(0.09)	(0.16)	(5.48)

III. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Based on the economic analysis presented above, the proposed repowering and acquisition of the Mower County Wind Facility is prudent. This will allow us to keep an efficient wind resource on our system further into the future, at a relatively low cost. Relative to continuing the current PPA, the acquisition provides substantial savings for our customers.

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

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

NORTHERN STATES POWER COMPANY
ADVANCE PRUDENCE – ACQUISITION OF
98.9 MW MOWER COUNTY WIND FACILITY

CASE NO. PU-19-____

VERIFICATION

STATE OF MINNESOTA)
)SS.
COUNTY OF HENNEPIN)

Philip Joseph Martin, being first duly sworn on oath, deposes and says that he is the Director of Resource Planning and Bidding for Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony submitted in the above-captioned matter under his name was prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

Philip Joseph Martin

Subscribed and sworn to before me on this 26 day of August, 2019

James G. Erickson
Notary Public
Minnesota
My Commission Expires January 31, 2024

Notary Public
My Commission expires: 1-31-24

STRATEGIST MODELING ASSUMPTIONS

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.53 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 1: Discount Rate and Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	46.16%	4.80%	2.22%	1.60%
Common Equity	52.35%	9.35%	4.90%	4.90%
Short-Term Debt	1.49%	3.65%	0.05%	0.04%
Total			**7.17%**	**6.53%**

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% 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 8.4 percent from the 2018-2019 LOLE Study Report published November 2017. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 8.4\%) - 1 = 2.98\%.$$

D. CO_2 Costs

For the Minnesota modeling, PVSC Base Case CO2 values are based on the high environmental cost values for CO2 through 2024 (page 31 of the Minnesota 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 GPDIPD of 113.416 and then escalate 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 E-999/DI-17-53 issued June 11, 2018). All prices escalate at general inflation.

The MPUC's 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 MPUC's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below. These values are used for the Minnesota application only and are not used in the modeling for the North Dakota application for advanced determination of prudence.

Table 2: CO2 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

For the Minnesota modeling, the values of the criteria pollutants are derived from the high and low values for each of the 3 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 GPDIPD of 113.416. The high, low and midpoint externality costs will be used in the CO2 sensitivities as described above. Note that these values are used for the Minnesota application only and are not used in the modeling for the North Dakota application.

Table 3: Externality Costs

MPUC Low Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,116	$4,829	$3,643	$0
NOx	$2,934	$2,622	$2,110	$28
PM2.5	$10,697	$6,856	$3,654	$872
CO	$1.65	$1.17	$0.31	$0.31
Pb	$4,857	$2,562	$624	$624

MPUC High Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$15,288	$12,030	$8,878	$0
NOx	$8,390	$7,798	$6,771	$158
PM2.5	$26,721	$17,091	$8,973	$1,327
CO	$3.51	$2.08	$0.63	$0.63
Pb	$6,011	$3,094	$695	$695

MPUC Midpoint Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$10,702	$8,430	$6,261	$0
NOx	$5,662	$5,210	$4,441	$93
PM2.5	$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 2018 load forecast is used as the base assumption and assumes that EV impacts grow through 2023 are then held constant for the remaining forecast period. The energy efficiency (EE) forecast included in this forecast assumes impacts at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

The "Load Forecast with 1.5% EE" shown in Table 4 below is the starting point for the Strategist load inputs. In all modeling scenarios, the "1.5% EE" is removed - the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2047. In its place, three EE Bundles (discussed below) are included in Strategist as Proview Alternatives and any number of these bundles (from 0 to all 3) is allowed to be selected as part of the optimization process. The resulting forecast, before the optimized EE bundles are added, is shown below in Table 4 as "Forecast Without 1.5% EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource in Strategist, not a load modifier.

Table 4: Strategist Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with 1.5% EE	Forecast without 1.5% EE	Forecast with 1.5% EE	Forecast without 1.5% EE
2018	9,152	9,152	43,914	43,914
2019	9,136	9,136	43,798	43,798
2020	9,156	9,227	43,865	44,310
2021	9,191	9,333	43,560	44,447
2022	9,251	9,464	43,529	44,860
2023	9,285	9,569	43,394	45,168
2024	9,329	9,684	43,425	45,650
2025	9,354	9,780	43,257	45,919
2026	9,403	9,900	43,281	46,386
2027	9,487	10,055	43,493	47,042
2028	9,593	10,262	44,089	48,093
2029	9,635	10,403	43,972	48,408
2030	9,697	10,567	44,130	49,010
2031	9,740	10,713	44,172	49,496
2032	9,856	10,956	44,661	50,445
2033	10,005	11,211	44,875	51,087
2034	10,137	11,343	45,232	51,443
2035	10,248	11,368	45,534	51,302
2036	10,374	11,408	46,042	51,382
2037	10,482	11,430	46,126	51,006
2038	10,576	11,438	46,287	50,723
2039	10,674	11,449	46,541	50,534
2040	10,777	11,467	46,946	50,505
2041	10,873	11,476	46,975	50,081
2042	10,964	11,481	47,143	49,805
2043	11,057	11,488	47,407	49,626
2044	11,169	11,514	47,823	49,603
2045	11,241	11,500	47,879	49,210
2046	11,328	11,500	48,076	48,964
2047	11,424	11,510	48,372	48,816
2048	11,536	11,536	48,977	48,977
2049	11,626	11,626	48,811	48,811
2050	11,715	11,715	49,042	49,042
2051	11,804	11,804	49,274	49,274
2052	11,893	11,901	49,640	49,640
2053	11,982	11,992	49,736	49,736
2054	12,071	12,083	49,968	49,968
2055	12,160	12,174	50,199	50,199
2056	12,249	12,265	50,567	50,567
2057	12,339	12,356	50,662	50,662

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 5 and Table 6, and are incremental/decremental to the forecast shown in Table 4.

Table 5: High Load Sensitivity

High Electrification		
Year	Energy (GWh)	Demand (MW)
2018	35	8
2019	46	6
2020	59	7
2021	166	20
2022	276	33
2023	390	47
2024	507	62
2025	627	77
2026	785	96
2027	976	117
2028	1,194	141
2029	1,579	171
2030	2,122	207
2031	2,802	250
2032	3,622	302
2033	4,593	362
2034	5,706	430
2035	6,969	509
2036	8,320	592
2037	9,751	681
2038	11,248	772
2039	12,797	866
2040	14,387	961
2041	15,950	1,055
2042	17,472	1,146
2043	18,940	1,245
2044	20,341	1,930
2045	21,665	2,660
2046	22,904	3,318
2047	24,054	3,945
2048	25,112	4,800
2049	26,076	5,056
2050	26,947	5,554
2051	28,051	6,093
2052	29,061	6,564
2053	30,072	7,041
2054	31,083	7,528
2055	32,093	8,021
2056	33,104	8,496
2057	34,115	8,984

**Demand values are coincident to system peak*

Table 6: Low Load Sensitivity

High DER Growth			
Year	Energy (GWh)	ELCC (MW)	Demand (Nameplate MW)
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	189	72	144
2022	173	66	131
2023	159	60	121
2024	144	55	109
2025	135	51	103
2026	230	87	175
2027	228	87	173
2028	369	140	280
2029	377	143	286
2030	432	164	328
2031	490	186	373
2032	553	210	420
2033	617	235	469
2034	687	261	522
2035	760	289	578
2036	840	319	637
2037	920	350	700
2038	1,007	383	766
2039	1,099	418	836
2040	1,200	455	910
2041	1,225	466	931
2042	1,187	451	902
2043	1,148	437	873
2044	1,112	422	844
2045	1,070	407	814
2046	1,014	385	771
2047	974	370	740
2048	935	354	709
2049	891	339	677
2050	850	323	646
2051	799	304	607
2052	759	287	575
2053	701	266	532
2054	657	249	498
2055	607	230	461
2056	559	211	422
2057	506	192	383

G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota Department of Commerce's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are incremental to the "Forecast without 1.5% EE" shown in Table 4. They are also dependent on the Bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected). The Bundles are included in Strategist as Proview Alternatives and any number of these Bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 7: Energy Efficiency Bundles

	Energy(MWh)			Demand (MW)			Costs ($000)		
Year	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 and, the same as for EE, are dependent on the Bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected). These Bundles are included in Strategist as Proview Alternatives and any number of the Bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 8: Demand Response Forecast

Year	Demand (MW) Adjusted For Reserve Margin: Base Demand Response Forecast	Demand (MW): Bundle 1	Demand (MW): Bundle 2	Demand (MW): Bundle 3	Costs ($000): Bundle 1	Costs ($000): Bundle 2	Costs ($000): Bundle 3
2018	848	0	0	0	0	0	0
2019	924	0	0	0	0	0	0
2020	940	270	107	89	14,380	7,659	11,311
2021	955	290	112	97	15,724	8,150	12,587
2022	970	312	116	106	17,212	8,676	14,016
2023	989	322	120	110	18,124	9,137	14,758
2024	1007	339	132	101	19,512	10,277	13,829
2025	1023	380	145	92	22,305	11,459	12,858
2026	1038	392	151	93	23,475	12,207	13,326
2027	1053	406	159	95	24,786	13,080	13,845
2028	1066	421	168	97	26,245	14,086	14,418
2029	1054	438	178	99	27,859	15,231	15,047
2030	1043	456	189	101	29,637	16,522	15,734
2031	1032	476	201	104	31,551	17,926	16,467
2032	1021	497	214	106	33,612	19,451	17,251
2033	1010	519	227	109	35,832	21,109	18,088
2034	1000	542	242	112	38,224	22,911	18,984
2035	990	567	257	116	40,802	24,870	19,943
2036	981	594	274	119	43,582	26,999	20,971
2037	972	630	293	125	46,580	29,313	22,072
2038	963	660	312	129	49,814	31,829	23,253
2039	954	692	332	133	53,305	34,564	24,522
2040	945	726	353	138	57,073	37,537	25,884
2041	937	726	353	138	58,215	38,288	26,402
2042	929	726	353	138	59,379	39,054	26,930
2043	921	726	353	138	60,566	39,835	27,468
2044	913	726	353	138	61,778	40,632	28,018
2045	906	726	353	138	63,013	41,444	28,578
2046	898	726	353	138	64,274	42,273	29,150
2047	891	726	353	138	65,559	43,118	29,733
2048	884	726	353	138	66,870	43,981	30,327
2049	876	726	353	138	68,208	44,860	30,934
2050	869	726	353	138	69,572	45,758	31,552
2051	862	726	353	138	70,963	46,673	32,183
2052	854	726	353	138	72,382	47,606	32,827
2053	847	726	353	138	73,830	48,558	33,484
2054	839	726	353	138	75,307	49,530	34,153
2055	832	726	353	138	76,813	50,520	34,836
2056	825	726	353	138	78,349	51,531	35,533
2057	817	726	353	138	79,916	52,561	36,244

**Demand values are coincident to system peak.*

I. Fuel Price Forecasts

The natural gas prices are developed using a blend of market information (New York Mercantile Exchange 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_2 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 9 below shows the market prices under zero CO_2 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 in year 2022.

Table 9: Fuel and Market Price Forecasts

	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)	
Year	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	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12
2020	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97
2021	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97
2022	$2.23	$2.52	$24.93	$19.30	$2.19	$2.44	$24.18	$18.72	$2.26	$2.59	$25.68	$19.88
2023	$2.29	$2.82	$28.39	$22.16	$2.24	$2.59	$26.08	$20.36	$2.34	$3.06	$30.80	$24.04
2024	$2.37	$3.07	$30.69	$23.93	$2.29	$2.70	$27.02	$21.07	$2.45	$3.47	$34.66	$27.03
2025	$2.42	$3.26	$32.82	$25.48	$2.34	$2.79	$28.06	$21.79	$2.51	$3.79	$38.13	$29.61
2026	$2.48	$3.42	$34.50	$27.03	$2.38	$2.85	$28.81	$22.58	$2.59	$4.06	$41.02	$32.14
2027	$2.55	$3.51	$35.03	$27.53	$2.43	$2.89	$28.86	$22.68	$2.68	$4.24	$42.22	$33.19
2028	$2.62	$3.60	$35.52	$27.78	$2.48	$2.93	$28.90	$22.60	$2.77	$4.40	$43.35	$33.90
2029	$2.69	$3.82	$37.34	$29.17	$2.54	$3.02	$29.53	$23.07	$2.87	$4.79	$46.83	$36.59
2030	$2.76	$4.09	$39.20	$30.60	$2.59	$3.13	$29.95	$23.38	$2.97	$5.31	$50.84	$39.69
2031	$2.84	$4.26	$41.18	$32.22	$2.64	$3.19	$30.85	$24.13	$3.07	$5.63	$54.45	$42.60
2032	$2.92	$4.47	$42.61	$33.54	$2.70	$3.27	$31.17	$24.53	$3.18	$6.05	$57.66	$45.38
2033	$3.00	$4.74	$45.01	$35.50	$2.75	$3.37	$31.99	$25.24	$3.30	$6.60	$62.64	$49.41
2034	$3.08	$4.93	$46.64	$37.01	$2.81	$3.44	$32.51	$25.80	$3.42	$6.99	$66.15	$52.51
2035	$3.17	$4.94	$46.91	$37.38	$2.87	$3.44	$32.65	$26.02	$3.54	$7.02	$66.64	$53.11
2036	$3.26	$5.00	$46.72	$37.35	$2.93	$3.46	$32.33	$25.85	$3.67	$7.15	$66.75	$53.37
2037	$3.35	$5.17	$48.19	$38.46	$2.99	$3.52	$32.81	$26.19	$3.81	$7.51	$69.97	$55.84
2038	$3.44	$5.40	$49.56	$40.01	$3.06	$3.60	$33.03	$26.67	$3.95	$8.00	$73.47	$59.32
2039	$3.51	$5.65	$51.50	$41.70	$3.11	$3.68	$33.54	$27.16	$4.05	$8.57	$78.09	$63.23
2040	$3.61	$5.90	$53.12	$43.28	$3.18	$3.76	$33.87	$27.60	$4.20	$9.14	$82.24	$67.00
2041	$3.69	$6.08	$54.73	$44.58	$3.24	$3.82	$34.39	$28.01	$4.31	$9.55	$85.97	$70.04
2042	$3.77	$6.27	$56.47	$46.00	$3.30	$3.88	$34.93	$28.46	$4.42	$10.01	$90.07	$73.38
2043	$3.85	$6.46	$58.13	$47.35	$3.36	$3.94	$35.44	$28.88	$4.53	$10.45	$94.04	$76.61
2044	$3.93	$6.57	$59.12	$48.17	$3.43	$3.97	$35.75	$29.12	$4.65	$10.72	$96.46	$78.59
2045	$4.02	$6.66	$59.90	$48.80	$3.49	$4.00	$35.99	$29.32	$4.77	$10.93	$98.37	$80.14
2046	$4.11	$6.77	$60.93	$49.63	$3.56	$4.03	$36.29	$29.57	$4.89	$11.21	$100.88	$82.19
2047	$4.20	$6.96	$62.70	$51.07	$3.63	$4.09	$36.82	$29.99	$5.02	$11.69	$105.27	$85.75
2048	$4.29	$7.17	$64.55	$52.57	$3.70	$4.15	$37.37	$30.44	$5.15	$12.21	$109.93	$89.54
2049	$4.38	$7.25	$65.25	$53.15	$3.77	$4.17	$37.57	$30.60	$5.29	$12.41	$111.72	$91.01
2050	$4.48	$7.37	$66.39	$54.08	$3.85	$4.21	$37.90	$30.87	$5.43	$12.73	$114.66	$93.38
2051	$4.58	$7.52	$67.67	$55.12	$3.92	$4.25	$38.27	$31.17	$5.57	$13.10	$117.97	$96.08
2052	$4.68	$7.66	$68.99	$56.19	$4.00	$4.29	$38.64	$31.47	$5.72	$13.49	$121.42	$98.90
2053	$4.79	$7.81	$70.33	$57.28	$4.08	$4.33	$39.02	$31.78	$5.87	$13.88	$124.95	$101.77
2054	$4.89	$7.96	$71.68	$58.39	$4.16	$4.38	$39.39	$32.08	$6.03	$14.28	$128.56	$104.71
2055	$5.00	$8.12	$73.07	$59.51	$4.25	$4.42	$39.77	$32.39	$6.18	$14.69	$132.28	$107.74
2056	$5.11	$8.27	$74.48	$60.67	$4.33	$4.46	$40.16	$32.71	$6.34	$15.12	$136.13	$110.87
2057	$5.21	$8.43	$75.92	$61.83	$4.41	$4.50	$40.54	$33.02	$6.49	$15.55	$140.05	$114.06

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 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	4.62	4.71	4.81	4.90	5.00	5.10	5.20	5.31	5.41	5.52	5.63	5.74	5.86	5.98	6.10	6.22	6.34	6.47	6.60	6.73
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
$/kw-mo	6.87	7.00	7.14	7.29	7.43	7.58	7.73	7.89	8.04	8.20	8.37	8.54	8.71	8.88	9.06	9.24	9.42	9.61	9.80	10.00

L. Effective Load Carrying Capability (ELCC) 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 15.6% of their nameplate rating per MISO 2017/2018 Wind Capacity Report. The ELCC for generic solar is 50% of the AC nameplate capacity. The ELCC for a generic 4-hour battery is equal to 100% of their AC equivalent capacity.

M. Spinning Reserve Requirement

Spinning reserve is the on-line 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 $500/MWh and is used to cover events where there are not enough resources available to meet system energy requirements.

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.

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

Table 11: Transmission Delivery Costs

Transmission Delivery Costs				
	CC	CT	Wind	Solar
$/kw	500	200	400	140

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 developed by the Company using the MISO MTEP 2018 models and looking at the average congestion costs between representative wind bus locations and NSP.NSP. Congestion costs are applied to new wind projects only.

Table 12: Integration and Congestion Costs

Integration and Congestion Costs ($/MWh)				
Year	Integration		Congestion	
	Wind	Solar	Wind	Solar
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.41	0.41	3.43	0.00
2021	0.42	0.42	3.50	0.00
2022	0.43	0.43	3.57	0.00
2023	0.44	0.44	3.64	0.00
2024	0.45	0.45	3.71	0.00
2025	0.46	0.46	3.79	0.00
2026	0.47	0.47	3.86	0.00
2027	0.48	0.48	3.94	0.00
2028	0.49	0.49	4.02	0.00
2029	0.49	0.49	4.10	0.00
2030	0.50	0.50	4.18	0.00
2031	0.51	0.51	4.27	0.00
2032	0.53	0.53	4.35	0.00
2033	0.54	0.54	4.44	0.00
2034	0.55	0.55	4.53	0.00
2035	0.56	0.56	4.62	0.00
2036	0.57	0.57	4.71	0.00
2037	0.58	0.58	4.80	0.00
2038	0.59	0.59	4.90	0.00
2039	0.60	0.60	5.00	0.00
2040	0.62	0.62	5.10	0.00
2041	0.63	0.63	5.20	0.00
2042	0.64	0.64	5.30	0.00
2043	0.65	0.65	5.41	0.00
2044	0.67	0.67	5.52	0.00
2045	0.68	0.68	5.63	0.00
2046	0.69	0.69	5.74	0.00
2047	0.71	0.71	5.86	0.00
2048	0.72	0.72	5.97	0.00
2049	0.74	0.74	6.09	0.00
2050	0.75	0.75	6.22	0.00
2051	0.77	0.77	6.34	0.00
2052	0.78	0.78	6.47	0.00
2053	0.80	0.80	6.60	0.00
2054	0.81	0.81	6.73	0.00
2055	0.83	0.83	6.86	0.00
2056	0.84	0.84	7.00	0.00
2057	0.86	0.86	7.14	0.00

Q. Distributed Generation and Community Solar Gardens

The distributed solar inputs are based on the most recent Company forecasts. Annual additions are modeled assuming a degradation of half a percent annually in generation, and a 25-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. The Company expects a transition from Solar*Rewards to non-incentivized DG over time due to the end of statutory provisions.

Table 13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)				
Year	Solar Rewards	Net Metered	Community Gardens	Total
2018	29	18	246	293
2019	41	27	504	573
2020	49	37	641	727
2021	53	47	649	749
2022	56	58	657	771
2023	57	70	665	792
2024	57	83	673	813
2025	56	96	681	834
2026	56	109	689	854
2027	56	122	697	875
2028	55	135	705	895
2029	55	147	713	915
2030	55	160	720	935
2031	55	172	728	955
2032	54	185	736	975
2033	54	197	744	995
2034	51	212	751	1,014
2035	45	229	759	1,033
2036	39	247	766	1,052
2037	34	262	774	1,070
2038	27	280	781	1,088
2039	16	301	789	1,106
2040	8	319	796	1,123
2041	4	333	804	1,141
2042	0	346	808	1,154
2043	0	358	796	1,154
2044	0	368	781	1,149
2045	0	379	776	1,155
2046	0	389	783	1,171
2047	0	399	789	1,188
2048	0	409	795	1,205
2049	0	419	802	1,221
2050	0	429	808	1,237
2051	0	439	814	1,254
2052	0	449	821	1,270
2053	0	459	827	1,286
2054	0	469	833	1,302
2055	0	479	839	1,318
2056	0	488	845	1,334
2057	0	498	852	1,350

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_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

S. Thermal Power Purchase Agreement (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_2, NO_x, CO_2, 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 hourly patterns are developed through a "Typical Wind Year" process where individual months are selected from the years 2014-2017 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each wind farm. For farms where generation data is not complete or not available, data from nearby similar farms is used.

Solar hourly patterns are taken from the ELCC Study from Fall 2013 and updated to reflect the ELCC as stated above.

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 battery costs are based on Public Service of Colorado All-Source Solicitation bids (Nov 28, 2017) with a 10% annual price improvement rate. Generic renewable costs and capacity factors are from National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Utility-scale wind and solar costs shown in Tables 16-18 include transmission costs from Table 10, while DG/distributed solar does not.

The Reference Case assumes "no going back" on renewables, meaning that we are committed to pursuing repowering and/or contract extension opportunities for renewable resources that will expire , and renewable resources are replaced "in-kind" when they reach end of life. Starting in 2023, generic solar is added to maintain at a minimum the 2015 IRP Preferred Plan solar levels. In 2023, there is approximately 1,800 GWhs of solar (both utility scale and DG solar) on the system which will grow to approximately 4,500 GWhs by 2028. The Company has already procured the levels of wind contemplated in the previous Resource Plan, so no minimum level of generic wind additions are needed. Additional renewables are included as Proview Alternatives.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind and solar costs are based on the National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Low and high battery costs are based the percent difference in the NREL ATB low / high battery costs compared to the NREL ATB base costs, with this percent difference applied to the Company's base battery cost forecast. Below is a list of typical operating and cost inputs for each generic resource.

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_2, NO_x, CO_2, 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 14: Thermal Generic Information (Costs in 2018 Dollars)

Thermal Generic Information					
Resource	**Sherco CC**	**Generic CC**	**Generic CT**	**Generic CT**	**Generic CT**
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 ($000-yr) 2018$	$15,000	$19,058	$2,165	$1,342	$2,165
Gas Pipeline CIAC ($000) 2018 $	$192,000	NA	NA	NA	NA
Capital Cost ($/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$	$17.96	$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	$14.46	$16.19	$5.96	$6.27	$8.14
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 15: Renewable Generic Information (Costs in 2018 Dollars)

Renewable Generic Information				
Resource	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
ELCC Capacity Credit (%)	15.6%	50.0%	50.0%	50.0%
Capacity Factor	50.0%	17.7%	14.0%	14.8%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	400	140	0	0

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

Storage Generic Information	
Resource	Battery
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	321
Summer Peak Capacity (MW)	321
Storage Volume (hrs)	4
Cycle Efficiency (%)	88
Equivalent Full Cycles per Year	156
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$10.53

Table 17: Levelized Capacity Costs by In-Service 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	$8.14	$6.27	$5.96	$16.19	$14.46			
2019	$8.31	$6.40	$6.08	$16.51	$14.75			
2020	$8.47	$6.53	$6.20	$16.84	$15.04			
2021	$8.64	$6.66	$6.33	$17.18	$15.35			
2022	$8.81	$6.79	$6.46	$17.52	$15.65			
2023	$8.99	$6.93	$6.58	$17.88	$15.97	$10.53	$8.03	$13.71
2024	$9.17	$7.07	$6.72	$18.23	$16.28	$9.48	$6.99	$12.51
2025	$9.35	$7.21	$6.85	$18.60	$16.61	$8.91	$6.35	$11.92
2026	$9.54	$7.35	$6.99	$18.97	$16.94	$8.53	$5.90	$11.41
2027	$9.73	$7.50	$7.13	$19.35	$17.28	$8.24	$5.53	$11.04
2028	$9.93	$7.65	$7.27	$19.74	$17.63	$8.02	$5.20	$10.73
2029	$10.13	$7.80	$7.41	$20.13	$17.98	$7.83	$4.92	$10.49
2030	$10.33	$7.96	$7.56	$20.53	$18.34	$7.68	$4.65	$10.28
2031	$10.53	$8.12	$7.71	$20.94	$18.71	$7.54	$4.51	$10.19
2032	$10.75	$8.28	$7.87	$21.36	$19.08	$7.42	$4.39	$10.13
2033	$10.96	$8.44	$8.03	$21.79	$19.46	$7.31	$4.27	$10.08
2034	$11.18	$8.61	$8.19	$22.23	$19.85	$7.22	$4.16	$10.05
2035	$11.40	$8.79	$8.35	$22.67	$20.25	$7.13	$4.05	$10.02
2036	$11.63	$8.96	$8.52	$23.12	$20.65	$7.05	$3.94	$10.02
2037	$11.86	$9.14	$8.69	$23.59	$21.07	$6.98	$3.83	$10.03
2038	$12.10	$9.32	$8.86	$24.06	$21.49	$6.91	$3.73	$10.05
2039	$12.34	$9.51	$9.04	$24.54	$21.92	$6.85	$3.63	$10.07
2040	$12.59	$9.70	$9.22	$25.03	$22.36	$6.79	$3.53	$10.09
2041	$12.84	$9.89	$9.40	$25.53	$22.80	$6.73	$3.44	$10.11
2042	$13.10	$10.09	$9.59	$26.04	$23.26	$6.68	$3.36	$10.13
2043	$13.36	$10.29	$9.78	$26.56	$23.72	$6.63	$3.28	$10.15
2044	$13.63	$10.50	$9.98	$27.09	$24.20	$6.58	$3.20	$10.17
2045	$13.90	$10.71	$10.18	$27.63	$24.68	$6.54	$3.12	$10.20
2046	$14.18	$10.92	$10.38	$28.19	$25.18	$6.50	$3.10	$10.13
2047	$14.46	$11.14	$10.59	$28.75	$25.68	$6.46	$3.09	$10.07
2048	$14.75	$11.37	$10.80	$29.33	$26.19	$6.42	$3.07	$10.01
2049	$15.05	$11.59	$11.02	$29.91	$26.72	$6.38	$3.06	$9.96
2050	$15.35	$11.82	$11.24	$30.51	$27.25	$6.35	$3.04	$9.91
2051	$15.65	$12.06	$11.46	$31.12	$27.80	$6.31	$3.03	$9.85
2052	$15.97	$12.30	$11.69	$31.74	$28.35	$6.28	$3.01	$9.80
2053	$16.29	$12.55	$11.93	$32.38	$28.92	$6.25	$3.00	$9.76
2054	$16.61	$12.80	$12.16	$33.03	$29.50	$6.22	$2.98	$9.71
2055	$16.94	$13.06	$12.41	$33.69	$30.09	$6.19	$2.97	$9.66
2056	$17.28	$13.32	$12.66	$34.36	$30.69	$6.16	$2.95	$9.62
2057	$17.63	$13.58	$12.91	$35.05	$31.30	$6.13	$2.94	$9.58

Table 18: Base Renewable Levelized Costs by In-Service Year

Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$29.79	$40.00	$73.92	$97.93
2021	$29.65	$40.00	$71.77	$91.35
2022	$34.04	$40.00	$70.71	$88.46
2023	$38.61	$49.48	$69.59	$87.04
2024	$43.39	$49.90	$68.41	$85.55
2025	$52.15	$50.32	$67.18	$83.98
2026	$52.55	$50.74	$65.88	$82.34
2027	$52.98	$51.17	$64.53	$80.63
2028	$53.42	$51.59	$63.11	$78.83
2029	$53.89	$52.01	$61.62	$76.95
2030	$54.39	$52.43	$60.07	$74.98
2031	$54.95	$53.10	$60.66	$75.15
2032	$55.54	$53.78	$61.25	$75.28
2033	$56.16	$54.47	$61.84	$75.40
2034	$56.80	$55.16	$62.43	$75.49
2035	$57.47	$55.86	$63.02	$75.56
2036	$58.17	$56.57	$63.61	$75.60
2037	$58.91	$57.28	$64.20	$75.61
2038	$59.67	$58.00	$64.78	$75.60
2039	$60.47	$58.72	$65.37	$75.56
2040	$61.30	$59.45	$65.95	$75.49
2041	$62.17	$60.13	$66.88	$76.33
2042	$63.07	$60.81	$67.82	$77.18
2043	$64.01	$61.50	$68.77	$78.04
2044	$64.99	$62.18	$69.74	$78.89
2045	$66.01	$62.87	$70.71	$79.76
2046	$67.07	$63.57	$71.70	$80.62
2047	$68.17	$64.27	$72.70	$81.49
2048	$69.32	$64.97	$73.71	$82.36
2049	$70.52	$65.68	$74.73	$83.24
2050	$71.76	$66.38	$75.76	$84.07
2051	$73.20	$67.71	$77.28	$85.75
2052	$74.66	$69.07	$78.83	$87.47
2053	$76.16	$70.45	$80.40	$89.22
2054	$77.68	$71.86	$82.01	$91.00
2055	$79.23	$73.29	$83.65	$92.82
2056	$80.82	$74.76	$85.32	$94.68
2057	$82.43	$76.25	$87.03	$96.57

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

Table 19: Low Renewable Levelized Costs by In-Service Year

Low Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$25.51	$35.18	$56.57	$94.61
2021	$24.43	$35.18	$51.50	$85.46
2022	$27.80	$35.18	$50.18	$81.18
2023	$31.28	$43.52	$48.81	$78.32
2024	$34.89	$43.21	$47.40	$75.38
2025	$42.41	$42.88	$45.95	$72.34
2026	$41.50	$42.54	$44.44	$69.21
2027	$40.53	$42.17	$42.89	$65.98
2028	$39.52	$41.79	$41.28	$62.65
2029	$38.00	$41.39	$39.63	$59.22
2030	$37.80	$40.97	$37.93	$55.69
2031	$37.66	$41.28	$37.65	$53.91
2032	$38.06	$41.58	$37.35	$52.04
2033	$38.48	$41.88	$37.03	$50.07
2034	$38.90	$42.28	$36.68	$48.02
2035	$39.34	$42.25	$36.30	$45.87
2036	$39.80	$42.39	$35.90	$43.62
2037	$40.26	$42.52	$35.47	$41.27
2038	$40.75	$42.64	$35.01	$38.81
2039	$41.24	$42.75	$34.52	$36.25
2040	$41.75	$42.85	$33.99	$33.57
2041	$42.27	$43.27	$34.47	$34.11
2042	$42.80	$43.39	$34.95	$34.64
2043	$43.35	$43.37	$35.44	$35.19
2044	$43.92	$43.33	$35.94	$35.75
2045	$44.50	$44.15	$36.44	$36.31
2046	$45.09	$43.34	$36.95	$36.88
2047	$45.70	$43.39	$37.46	$37.46
2048	$46.32	$43.42	$37.98	$38.05
2049	$46.96	$43.44	$38.50	$38.65
2050	$47.62	$43.97	$39.04	$39.22
2051	$48.57	$44.85	$39.82	$40.00
2052	$49.54	$45.74	$40.61	$40.80
2053	$50.53	$46.66	$41.43	$41.62
2054	$51.54	$47.59	$42.25	$42.45
2055	$52.57	$48.54	$43.10	$43.30
2056	$53.63	$49.51	$43.96	$44.17
2057	$54.70	$50.50	$44.84	$45.05

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

Table 20: High Renewable Levelized Costs by In-Service Year

High Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$34.70	$50.52	$88.96	$124.70
2021	$35.40	$50.52	$91.58	$127.20
2022	$40.61	$50.52	$93.41	$128.14
2023	$46.03	$62.48	$95.28	$130.70
2024	$51.64	$63.73	$97.19	$133.32
2025	$61.25	$65.01	$99.13	$135.98
2026	$62.49	$66.31	$101.11	$138.70
2027	$63.76	$67.63	$103.14	$141.48
2028	$65.06	$68.99	$105.20	$144.30
2029	$66.38	$70.37	$107.30	$147.19
2030	$67.72	$71.77	$109.45	$150.13
2031	$69.10	$73.21	$111.64	$153.14
2032	$70.50	$74.67	$113.87	$156.20
2033	$71.93	$76.17	$116.15	$159.32
2034	$73.39	$77.69	$118.47	$162.51
2035	$74.88	$79.24	$120.84	$165.76
2036	$76.39	$80.83	$123.26	$169.08
2037	$77.94	$82.45	$125.72	$172.46
2038	$79.52	$84.09	$128.24	$175.91
2039	$81.13	$85.78	$130.80	$179.42
2040	$82.77	$87.49	$133.42	$183.01
2041	$84.45	$89.24	$136.09	$186.67
2042	$86.16	$91.03	$138.81	$190.41
2043	$87.90	$92.85	$141.58	$194.21
2044	$89.68	$94.70	$144.42	$198.10
2045	$91.49	$96.60	$147.30	$202.06
2046	$93.34	$98.53	$150.25	$206.10
2047	$95.23	$100.50	$153.25	$210.22
2048	$97.15	$102.51	$156.32	$214.43
2049	$99.12	$104.56	$159.45	$218.72
2050	$101.12	$106.65	$162.63	$223.09
2051	$103.14	$108.79	$165.89	$227.55
2052	$105.21	$110.96	$169.21	$232.10
2053	$107.31	$113.18	$172.59	$236.75
2054	$109.46	$115.44	$176.04	$241.48
2055	$111.65	$117.75	$179.56	$246.31
2056	$113.88	$120.11	$183.15	$251.24
2057	$116.16	$122.51	$186.82	$256.26